PROMOTioN
PROGRESS ON MESHED HVDC OFFSHORE TRANSMISSION NETWORKS

D12.3 - Draft Deployment Plan

PROMOTioN – Progress on Meshed HVDC Offshore Transmission Networks
Mail info@promotion-offshore.net
Web www.promotion-offshore.net

This result is part of a project that has received funding form the European Union's Horizon 2020 research and innovation programme under grant agreement No 691714.

CONTACT
John NM Moore – john.moore@tennet.eu
Pierre Henneaux – Pierre.Henneaux@tractebel.engie.com

DOCUMENT INFO SHEET

Document Name: **Draft Deployment Plan**

Responsible partner: TenneT TSO B.V.

Work Package: WP12

Work Package leader: TenneT TSO B.V., John Moore

Task: T12.3

Task lead: TenneT TSO B.V., John Moore

DISTRIBUTION LIST

APPROVALS

	Name	Company
Validated by:		
Task leader:	John Moore	TenneT TSO B.V.
WP Leader:	John Moore	TenneT TSO B.V.

DOCUMENT HISTORY

Version	Date	Main modification	Author
1.1	7 May 2018	N/A	John Moore / Michiel de Schepper
1.2	8 October 2018	New Contents	Jelle van Uden
1.4	26 February 2020	Final Draft version	Jelle van Uden / Hannah Evans

WP Number	WP Title	Person months	Start month	End month
WP12	Deployment plan for future European offshore grid	177	12	54

Deliverable Number	Deliverable Title	Type	Dissemination level	Due Date
12.3	Draft Deployment Plan	Report	PROMOTioN	48

LIST OF CONTRIBUTORS

PARTNER	NAME
Carbon Trust	Hannah Evans
DNV-GL	Maksym Semenyuk
Energinet	Henrik Thomsen
FGH	Felix Rudolph, Hendrik Vennegeerts
Orsted	Lorenzo Zeni
TenneT	Jelle van Uden, John Moore, Patrycja Koltowska, Frank Westhoek, Tim Kroezen, Gabriele Simakauskaite,
Tractebel	Olivier Antoine, Pierre Henneaux

CONTENTS

LIST OF ABBREVIATIONS

ACRONYM	FULL NAME
AC	Alternating Current
ACCB	AC Circuit Breaker
ACER	Agency for the Cooperation of Energy Regulators
AIS	Air Insulated Switchgear
BAU	Business As Usual (Grid Concept)
BRP	Balance Responsible Party
BSP	Balance Service Provider
CAPEX	Capital Expenditure
CBA	Cost-Benefit Analysis
CBCA	Cross-Border Cost Allocation
CEF	Connection Europe Facility
DC	Direct Current
DCCB	Direct Current Circuit Breaker
DRU	Diode Rectifier Unit
EC	European Commission
EEPR	European Energy Programme for Recovery
EEZ	Exclusive Economic Zone
EIA	Environmental Impact Assessment
EC	European Commission
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSO-G	European Network of Transmission System Operators for Gas

EUR	European Distributed (Grid Concept)
EU	European Union
GIS	Gas Insulated Switchgear
HB	Half Bridge
HSS	High Speed Switch
HUB	European Centralised (Grid Concept)
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
ISO	Independent System Operator
FB	Full Bridge
KPI	Key Performance Indicator
MMC	Multi-Modular Converter
MOG	Meshed Offshore Grid
MTDC	Multi-terminal DC
NAT	National Distributed (Grid Concept)
NRA	National Regulatory Authority
OFTO	Offshore Transmission Owner
OPEX	Operational Expenditure
OWF	Offshore Wind Farm
PCI	Project of Common Interest
PINT	Putting-one-in-at-a-time
PROMOTioN	Progress on Meshed HVDC Offshore Transmission Networks
RCC	Regional Coordination Centre
RES	Renewable Energy Sources

SCFCL	Short Circuit Fault Current Limiter
SF_6	Sulphur hexafluoride gas
SM	Sub-Module
SOGL	System Operation Guidelines
SPV	Special Purpose Vehicle
TOOT	Taking-one-out-at-a-time
TRL	Technology Readiness Level
TSO	Transmission System Operator
TYNDP	Ten Year Network Development Plan
VSC	Voltage Source Converter
UK	United Kingdom
WP	Work Package

EXECUTIVE SUMMARY

INTRODUCTION

By the end of 2019, 22 GW of offshore wind capacity was installed across Europe with much of this capacity concentrated in the North Seas [1] (North Sea, Irish Sea, English Channel, Skagerrak Strait and Kattegat Bay). This is a 10-fold increase over the last decade, and continues to grow, with a clear pipeline of projects stretching into the 2020s across the North Seas countries [2]. Currently, most of this wind generation is transmitted to shore using point-to-point High Voltage Alternating Current (HVAC) connections. However, as the distance to shore increases, the need to use High Voltage Direct Current (HVDC) connections rises. This is especially true when point-to-point networks develop into meshed networks.

PROMOTioN (Progress on Meshed HVDC Offshore Transmission Networks), is a research project that has progressed four key technologies required to build, control and protect meshed HVDC transmission grids, namely control systems, DC circuit breakers (DCCBs), HVDC protection systems and Gas Insulated Switchgear (GIS)[1]. Alongside this technical work, recommendations have also been developed for the legal & governance frameworks needed for a meshed offshore grid (MOG) and the necessary economic and financial rules required to attract sufficient investment and fairly remunerate owners, operators and users of the grid. These key technologies and accompanying policy recommendations can be applied to multiple MOG configurations.

In Deliverable 12.2 multiple MOG configurations, or *concepts*, were analysed under three different scenarios. These concepts ranged in their regulatory and technological complexity, exploring the dimensions of intense international cooperation and the use of artificial islands as support structures. Simulating the development of an offshore grid with these different assumptions under three different wind generation scenarios allowed the discovery of differences and similarities between these concepts. The costs and benefits of these concepts were also analysed, using a methodology developed within PROMOTioN[2].

This analysis concluded that where energy evacuation and overall cost are the primary drivers, there are only slight differences to be found between the concepts in terms of cost and benefits. The current infeed constraints of the onshore grid required the use of 2 GW cables, the same maximum size of converters. However, analysis also showed that some particular configurations arise in each meshed concept, including the use of an offshore interconnector that is established between windfarms. Also, the cost reduction of using islands in place of platforms became apparent in this analysis. Additionally, aggregating the energy of multiple windfarms and transporting this to shore with a single cable is a competitive structure and arises in all concepts.

[1] Diode Rectifier Units, a type of converter, were initially studied in a separate Work Package within PROMOTioN, but this Work Package was terminated before the end of the project. To replace this, a Work Package on Gas Insulated Switchgear was commissioned.
[2] Deliverable 7.11

On the benefit side, meshing of the grid also generally leads to lower offshore curtailment and a higher security of supply and may therefore be beneficial in particular cases. Realising these benefits, will need changes in regulation as well as the application of novel technologies.

The aim of this document is to translate the results of the PROMOTioN project into practical and executable advice to the European Commission and other stakeholders to overcome barriers and advance the deployment of a MOG. This document includes a roadmap for the development of a MOG, pinpointing key grid development characteristics in each time period. It then summarises the key recommendations for all technical and non-technical aspects of a MOG and finally assigns these to stakeholders, thereby combining the anticipated development of the grid with the recommendations. An overview of the process to establish this deployment plan is given in Figure 1 below, where it is shown that the Cost-Benefit Analysis (CBA), technology recommendations and non-technological recommendations is combined into the deployment plan.

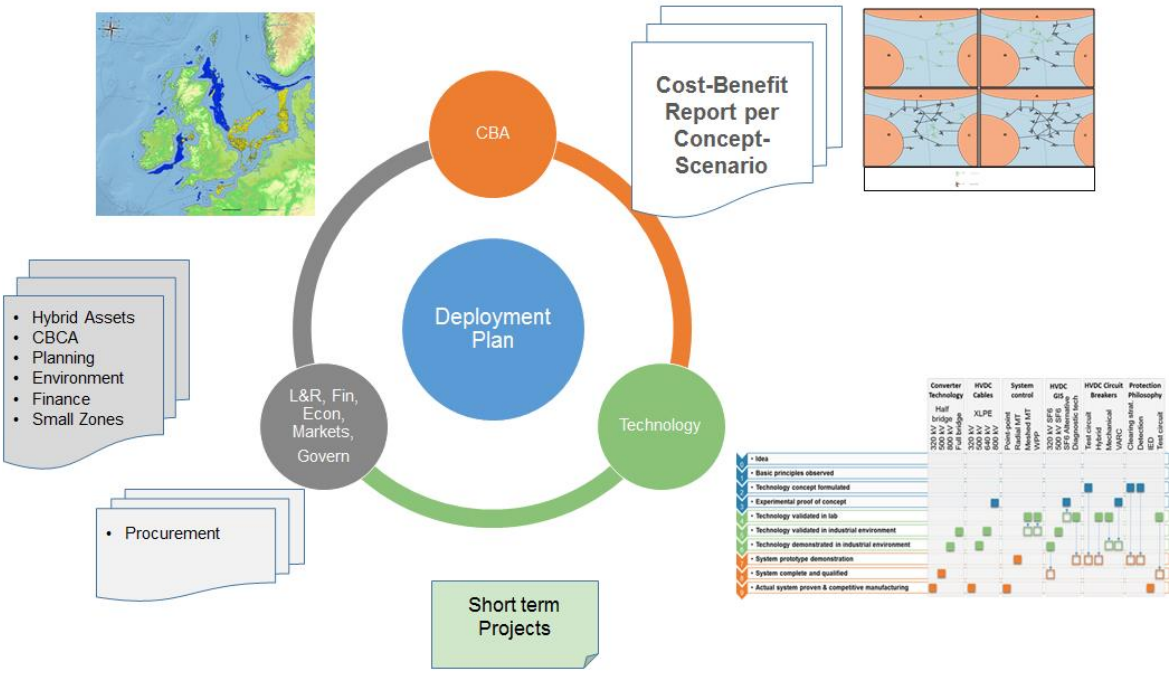


Figure 1 - Overview of the process to establlish the Deployment Plan

DEVELOPMENT OF THE GRID

Through the establishment of the topologies it was found that, in general, three periods can be distinguished in which different developments can be observed. The first period of 2025-2030 marks the start of the roll-out of the meshed grid, during which time radial connections dominate the grid and the meshed structure of the grid is concentrated to small areas. By 2035-2040, grid development takes off and more meshed structures start to appear, as well as hybrid interconnectors. 2045-2050 marks the end of the analysed period, where experiences gained in the previous periods can be applied to complete the integration of a large amount of offshore wind.

2020 – 2030

The first period in the development of the grid is characterised by the deployment of the first 2GW HVDC components and the construction of relatively simple multi-terminal meshed structures. These structures are

limited to the national EEZs, with potential cross-border synergies found for windfarms that are located close to the border of the EEZs. All six islands that are planned in the development of the topologies are already in place in the topology. However, this is only considered possible in the planning of these concepts and represents an ideal situation. In reality, planning and construction of these islands is not anticipated to be feasible by 2025. Complex protection is unnecessary in this phase, but PROMOTioN believes that the opportunity is there to industrially test a DCCB offshore.

2030 – 2040

The second period in grid development sees an increase in the rate of offshore wind deployment, with the establishment of the first hybrid assets and more complex cross-border meshing. It is in this period of the grid where the protection devices will be required, introducing a new technical complexity in the grid. Artificial islands may be established before this period and have their hosting capacity grow in this period to allow a significant amount of offshore wind to be connected. Bilateral or trilateral agreements (exemptions) may no longer be suitable, as increased meshing means more countries are connected via the same network.

2040 – 2050

The last period in the development of the grid marks the continuation of the complex structures in the grid. Multiple overlaying meshed grids might co-exist in the North Sea, increasing the overall complexity of the offshore grid. The capacity increase per time period continues to rise as well, demanding a smooth continued construction process. Where possible more interconnection capacity is established between countries, enabling the full integration of the North Seas markets.

TECHNOLOGY RECOMMENDATIONS

STANDARDISATION OF TECHNOLOGIES

Within PROMOTioN a choice has been made to analyse the development of offshore wind with the currently novel 525KV, 2GW HVDC equipment where applicable. The analysis concludes that 2 GW solutions may become widespread in the North Seas and therefore a standardisation of this solution will be required for an efficient roll-out of offshore wind. Standardisation of the technologies will require first a deployment of multiple 2 GW offshore HVDC hubs, after which a standardised format may be developed. In this analysis, it is assumed that bipole cables with a solid return are used. This is not a prerequisite, but does give a level of inherent security, and a certain redundancy.

MESHING

In all concepts and scenarios, the topology will evolve gradually from a few multi-terminal connections to a more complex structure. Eventually, a backbone is expected to interconnect several multi-terminal connections. It has also been shown that all wind scenarios require a high level of interconnection. The combined use of the offshore grid for wind evacuation and interconnectors is an important driver for meshing/multi-terminal. It is therefore recommended to apply hybrid interconnection in cases where this is optimal i.e. when two OWFs are in close vicinity to each other.

ARTIFICIAL ISLANDS

Artificial islands are expected to be a more cost-effective solution than platforms above a certain capacity Offshore Windfarms (OWFs). This capacity is difficult to analyse as this is dependent on multiple factors such as the position of the OWF relative to the island and its onshore connection point. The Low scenario, however, shows that smaller islands of <10 GW of hosting capacity seem to have no financial benefit in the PROMOTioN analysis.

OFFSHORE HVDC GRID CODE

Multiple recommendations from technical Work Packages for e.g. grid planning and operation and control of an offshore grid may be combined in an offshore HVDC grid code. This should contain enough information to safely and effectively construct and operate a MOG, including information on the choice for bipoles, voltage level, reliability of the grid, dynamic voltage ranges, Fault Ride Through capability, control requirements and black start capability. The Grid Code needs to be sufficiently detailed to enable grid integration between different areas and yet needs to be technology agnostic to allow for vendor innovations to be applicable in the grid.

INTEROPERABILITY

Interoperability is a requirement for technologies within the MOG. The components of the MOG will have to be able to work together; otherwise commissioning and control of the OWFs and the grid will not be possible. Standards for components will, therefore, have to be aligned among the cooperating North Seas countries probably within the existing standards organisations CIGRE and Cenelec. In addition, continued interoperability will require that manufacturers continue to take responsibility for their equipment and are prepared to adapt the interface of the devices to match changing conditions of the grid both in operation of the grid and while it grows. This guarantees that a grid extension may be possible with the same or updated components. This is likely to require changes to the typical contract structures and responsibilities between TSOs and suppliers.

PROTECTION STRATEGY

The protection strategy can be specifically chosen by each grid operator separately and according to the needs of the grid elements according PROMOTioN analysis. One of the conclusions is that disturbance far from a fault is less than anticipated. It is also found that it may be beneficial to be able to split the grid into different sections. There are no lock-in or interoperability issues expected from a difference in protection strategy by different grid operators.

DC CIRCUIT BREAKERS

It is recommended to install DCCBs only in coordinated grid solutions, or meshed topologies. Moreover, taking into account the fact that DCCBs are an expensive technology it is suggested to install them only on connections in which a fault can lead to a loss of power higher than the maximum loss of power infeed of the countries to which it is connected. DCCBs should first be demonstrated onshore in a real-life test setup as this is a less complex test environment than offshore. At the same time as delivering the onshore DCCB pilot project, preparations for the application of a DCCB in a real-life offshore setting can be made so that its

application can be tested in an offshore situation. Finally, DCCBs may be deployed offshore to protect the grid. Where DCCBs may be installed and how many there will be depends on the chosen protection strategy.

GAS INSULATED SWITCHGEAR

It is highly recommended to continue to develop and apply GIS technology for DC assets, as it is a more compact solution than air insulated switchgear (AIS) which is a significant advantage in offshore solutions. Sulphur hexafluoride (SF6), which has an extremely high global warming potential, is used as an insulating gas in current GIS installations. Therefore, it is recommended to develop other, less environmentally damaging insulating gases that can be used in GIS for both HVAC and HVDC applications. PROMOTioN is testing alternatives to SF_6, the results of which will be published during 2020. Similar to the DCCB pilot project, a HVDC GIS pilot project onshore would allow for testing of GIS technology in a real-life setting so it is ready for deployment by 2030. A successful onshore pilot project would provide a strong argument for the deployment of the technology in an offshore environment.

ANTICIPATORY INVESTMENTS

In combination with the offshore DCCB pilot project, PROMOTioN proposes the application of a platform that is ready for expansion for the possible application of a DCCB and/or an additional DC cable. Due to long planning lead-time this decision has to be made early to ensure the deployment of a very first expansion-ready platform. This requires an anticipatory investment, which is required when meshing an offshore grid. An artificial island can also be considered as an anticipatory investment, as this might need to be scaled to a larger area than initially necessary to allow for future OWFs to be connected to it. Lastly and most obviously, in the more meshed scenarios, the laying of larger cables than initially needed may be considered. All these assume that a developer/TSO can plan sufficiently in advance with the certainty that projects will go ahead.

FLEXIBILITY

With the high variability of offshore wind into the system, flexibilities might be required to secure the balance between demand and supply. In PROMOTioN analysis it has also been shown that a significant amount of offshore wind energy might be curtailed in the system as the onshore grid cannot cope with the transportation of wind energy to the load centres. Flexibilities may therefore also be necessary to allow the utilisation of all offshore wind energy. In the analysis within PROMOTioN, there is limited assessment of what is required

DC/DC CONVERTERS

The application of DC/DC converters, or DC transformers, may be required once the grid becomes complex and difficult to control. The application of DC/DC converters allows for better control of the power flow and also allows the coupling of (meshed) grids that are not operated at the same voltage. Currently, DC/DC converters are not ready for implementation, but research is continuing and they could be well applied in the MOG.

LEGAL, REGULATORY AND FINANCING RECOMMENDATIONS

COOPERATION – DEVELOPING A MIXED PARTIAL AGREEMENT

The development of a HVDC offshore grid is a complicated cross–border project with high investment requirements. Strong co-operation between countries at both a political and operational level will be necessary to develop the legal, regulatory, economic and financial frameworks for the MOG. As the MOG will incorporate EU and non-EU member states, it is recommended that, over the long-term, the co-operation arrangements are formalised through a mixed partial agreement; an international law agreement between the EU Member-States and third states connected to the MOG, and the EU. This could set out the common interpretation of international and EU laws in relation to offshore assets. This same mixed partial agreement could also set out the approach to other elements of MOG management, including:

- Aim and principles of the MOG
- Governance and decision-making structures
- Long-term OWF and grid planning procedures (geographical and temporal)
- Regulatory governance
- Decision-making processes in relation to long-term decision making and delegation of tasks to committees of national experts
- Legal certainty (formalising the decision-making process and appeals procedures)

CREATING A ROBUST LEGAL DEFINITION OF HYBRID ASSETS

A legal definition of an ‘offshore hybrid asset’ is necessary at both an EU and international level in order to distinguish MOG assets from radially connected wind farms and interconnectors between countries. An offshore hybrid asset combines the connection of OWFs with the interconnection between multiple countries. They are the building blocks of the MOG and can reduce the number of offshore cables required to connect a given level of generation capacity.

The absence of a definition for hybrid assets increases the risk that infrastructure wouldn’t be used efficiently, and either additional cables would be laid to circumvent the legal uncertainty increasing financial and environmental cost, or investors would be unwilling to invest in a MOG whilst legal uncertainty remained.

During the PROMOTioN project, progress has been made on defining ‘offshore hybrid assets.’ They are now defined in the Recitals to the Electricity Regulation. This is a great step forward however, the offshore hybrid asset definition does not yet provide the legal certainty needed for the construction of an offshore grid, as it only creates an exception possibility (new direct current interconnectors) and the possibility to provide case-by-case regulation for hybrid assets.

In the short term, PROMOTioN recommends that the ‘offshore hybrid asset’ should be adopted in the **operative** part of the Electricity Regulation rather than in the recital, and that the legislation should specify the legal and regulatory framework for offshore hybrid assets in more detail. This would provide greater legal certainty on how offshore hybrid assets should be treated from a regulatory perspective.

As the Meshed Offshore Grid will connect countries both inside and outside the EU, **in the long term**, an international agreement on the definition of an 'offshore hybrid asset’ and the extent of jurisdiction states have for such assets would provide greater legal certainty to all MOG connected countries. PROMOTioN therefore

recommends that a common agreed definition of 'offshore hybrid asset' is included in the mixed partial agreement mentioned in the previous section.

AGREEING THE APPROACH TO REGULATING THE GRID

National transmission networks are regulated by National Regulatory Authorities (NRAs) who typically determine the revenue received by transmission owners and operators (and the conditions and incentives linked to this), the quality and safety standards operators must adhere to, and the requirement for unbundling of different energy assets and the introduction of competition into markets previously dominated by monopolies.

At EU level, the Agency for the Cooperation of Energy Regulators (ACER) assists in coordination of activities across the NRAs, at an EU level, and, providing opinions and recommendations to TSOs, ENTSO-E, European Network of Transmission System Operators for Gas (ENTSO-G), NRAs, EU Parliament, EU Council and EU Commission on matters relating to cross border energy regulation. ACER is not a European Regulator but is an EU body responsible for promoting regulatory cooperation.

The MOG will need to be regulated by a single entity or through cooperation of NRAs. After examining all options, PROMOTioN recommends that the regulatory structure of the MOG should be set through the cooperation of the national NRAs. This arrangement can be set up more swiftly than other options (it is an extension of existing cooperation arrangements) and is likely to be more politically acceptable than setting up a new MOG-wide institution whilst still delivering the benefits of a coordinated approach. The NRAs should agree on transmission tariffs paid by OWFs, the revenue paid to transmission owners, the process for connecting to the MOG and operational requirements such as safety standards and day-to-day operational rules. Such cooperation can evolve over time, if coastal states are willing to increase the amount of cooperation and could eventually create a de-facto North Sea Regulator.

ENSURING SUFFICIENT INVESTMENT CAN BE ACCESSED

In some North Seas countries, TSO legal ownership restrictions hinder private equity provision and the amount of debt they can leverage. In addition, TSOs are also unlikely to be willing to risk their current credit rating by funding investment projects from their balance sheet.

Delivering the level of investment required for a MOG, particularly under a high wind deployment scenario, will require significant private debt and equity funding. It is unlikely to be practicable for TSOs to finance investment off-balance sheet or through public funds alone. Therefore, PROMOTioN recommends that alternative financing structures should be considered to enable new sources of finance to invest in transmission assets. Alternative structures, such as Special Purpose Vehicles (SPVs) for individual transmission projects, could allow additional finance to be raised whilst reducing the risk to the parent company.

The rapid growth of the UK sector is an illustration that sufficient funds should be available. The openness of governments to allow third party equity into their infrastructure will probably determine the speed and success of a roll out.

The construction of the grid will be a deployment of new technologies. In order to facilitate this, EU stimulus is seen as necessary. Certainly, the early deployment of technology, the support funds provided by the EU,

such as CEF, will be required. The industrial test of DCCBs offshore will most likely require an extended platform or a sub-platform to house the device, auxiliary equipment and make the cable connections.

MARKET RECOMMENDATIONS

SMALL BIDDING ZONES

Splitting the MOG into many small price zones appears to be the most attractive option for the remuneration of offshore wind parks, especially in case electricity is stored and/or converted to another energy carrier offshore. National price zones do not provide this incentive and may cause situations in which economically efficient dispatch would require trading power from a high price to a low price zone. A single offshore price zone avoids the latter, but still does not provide efficient incentives for power conversion (such as power to gas) or storage. Although power conversion is out of scope in the analyses of the topologies, when translating recommendations from theory into practice, practical considerations such as power conversion offshore are also important considerations.

The interconnection of different EEZs and potentially multiple small zones, does also require consideration of the subsidy regime that is used to stimulate the build of offshore wind farms. This may have to be modified in order to maintain an incentive for parks to be built.

GOVERNMENT RECOMMENDATIONS

SKILLED PERSONNEL

Skilled personnel are essential to facilitate the roll-out of offshore wind in all areas of the offshore grid, including construction of OWFs, construction of the grid, connection of the grid to the onshore grid, etc. Governments should ensure that sufficient training programmes are in place to meet long-term need for personnel and that these courses equip students with the skills needed by the industry in future years.

SUPPLY CHAIN

Investment in the supply chain will be necessary to deliver the rate of deployment required for offshore wind farms and transmission assets. Government investment in key supply chain assets could enable this.

RECOMMENDATIONS TO STAKEHOLDERS AND TIMING

In order to assign the stakeholder actions to a specific time period, each recommendation is grouped under the specific period of grid development in which it is perceived necessary and an indication is made of the time required to implement the recommendation. The status of progress on the action outside the PROMOTioN project is also given, distinguishing between no action taken, action ongoing but not yet finalised and action finalised. The stakeholders that have an interest in each recommendation are also given. An overview of the recommendations per period is given in the sections below and summarised in Figure 2.

THE PERIOD 2020 – 2030

By 2030 roll out is limited to current practices, except for the use of 2 GW HVDC components that are not yet used today. Already in the early stages of grid development, the establishment of an offshore HVDC grid code can ensure meshing of the grid in later periods. It will allow grid developers to independently develop the

offshore grid according to similar characteristics, allowing for meshing in later periods. In order to facilitate the deployment of DCCBs in later periods of grid development, an onshore DCCB pilot project should be setup. The PROMOTioN pilot project short term project allows for integration of a DCCB in a setting where testing can be facilitated in a real-life environment where the tests have little to no influence on the reliability of the environment it is tested in. Similarly, a GIS pilot project can be setup and GIS technology may be deployed already in early stages of the grid. Due a long regulatory lead-time up to the construction of an island hub, the hub may only start implementation by 2030, with only a short period between construction and operation once the regulation is settled.

As much of the offshore grid is still similar to the current offshore grid many current regulations may still apply in this period. However, as a minimum, bilateral agreements will be required to agree the regulatory framework and/or the support scheme for the connection of some OWFs that are only connected to other countries than in which EEZ they are located. These situations could not be managed under 'business as usual' regulation. The integration of these bilateral agreements into a future regulatory regime for the MOG would be much smoother if at this stage the key principles of MOG regulation and how regulatory decisions will be made across the North Seas had been agreed in the *North Sea treaty* as well as the definition of an offshore hybrid asset. An alternative to the hybrid asset classification may be delivered in the form of the small bidding zones, as already establishing a small bidding zone for the OWFs omits the necessity for a hybrid asset classification. Due to some locally meshed configurations, anticipatory investments must already be allowed in some North Sea countries, where the choice to build far offshore already early in the entire period is more logical.

Combining the OWFs to reach a critical size of 2 GW also entails the alignment of connection costs for OWF developers in the North Seas countries. In order to fully capture the opportunity to mesh early in the period, the CBCA methodology for meshed projects should also be completed in this period, allowing for the correct but pragmatic allocation of the costs and benefits of cross-border meshed configurations. Governments and Industry should be investing in supply chain and personnel development to facilitate the increased rate of deployment expected in later years. An overview of the actions in this period is made in Table 1.

Table 1 - Actions, their timing and the stakeholders in the period 2020 - 2030

ACTION	PREP.	IMPL.	NEC.	PROGRESS	IMPLEMENTER	INFLUENCER	USER
2GW 525 kV DC technologies	2020	2022	2025	Ongoing	TSOs/ OFTOs	Manufacturers	TSOs/ OFTOs
Interconnection meshing	2020	2025	2030	Ongoing	TSOs/ OFTOs		TSOs/ OFTOs
Island hub	2020	2030	2032	None	TSOs/ OFTOs	Governments	TSOs/ SOs
HVDC grid code	2020	2025	2030	Ongoing	ENTSO-E	TSOs/ OFTOs/ ACER/NRAs	TSOs/ OFTOs
Onshore DCCB pilot project	2020	2022	2025	Ongoing	TSOs/ OFTOs/ EU	TSOs/ OFTOs/ PROMOTioN/ manufacturers	TSOs/ OFTOs
Offshore DCCB pilot project	2022	2025	2028	Ongoing	TSOs/ OFTOs/ EU	TSOs/ OFTOs/ PROMOTioN/ manufacturers	TSOs/ OFTOs
GIS pilot project	2020	2022	2025	Final	TSOs/ OFTOs/ EU	TSOs/ OFTOs/ PROMOTioN/ manufacturers	TSOs/ OFTOs
GIS deployment	2025	2025	2027	Ongoing	TSOs/ OFTOs	PROMOTioN/ manufacturers	TSOs/ OFTOs
Anticipatory investments	2020	2025	2027	Ongoing	TSOs/ OFTOs	Governments	TSOs/ OFTOs
Small bidding zones – asset alternative	2025	2029	2030	Final	NRAs	TSOs/ OFTOs	TSOs/ SOs
Offshore hybrid asset	2020	2028	2030	Ongoing	EU		TSOs/ SOs
Connection costs alignment	2020	2025	2030	None	Governments	NRAs	TSOs/ SOs/ OWF developers
CBCA for meshed projects	2020	2025	2030	None	EU	TSOs/ OFTOs	TSOs/ SOs

THE PERIOD 2030 – 2040

As the rate of grid development increases over this period, the DCCBs necessary for protection should be ready for deployment. This is done through the pilot projects in the previous period. Although possibly important in other stages of grid development as well, it is especially necessary for technologies to be interoperable when meshing of the grid becomes complex. As more and more HVDC offshore technologies are deployed throughout the period, the technology will become standardised in order to save costs.

If small zones regulation is not yet applied as an alternative to hybrid assets, the configuration of the offshore grid will have become too complex to be able to regulate the bidding zones as an extension of the home bidding zone. The bidding zones regulations should therefore be implemented in this period.

During this period some early offshore wind assets will be decommissioned. It would therefore be useful to have decommissioning guidance agreed across North Sea countries before the end of the period.

The period also marks a large increase in the deployment rate of offshore wind capacity, which means that a dedicated supply chain should be established by this time. This also indicates a large opportunity for governments to increase the employment rate of skilled personnel in their countries.

Due to the complexity of the meshing, the remuneration of assets as it is regulated nowadays will no longer be viable. Therefore, if support is still required, this should be done through a joint support scheme. Similarly, aligned permitting should be implemented at the end of this period, as well as the remuneration regulation. These both could first be piloted in less complex meshed situations in the period before 2030, when meshes are still relatively straightforward. The actions for this period are summarised in Table 2.

Table 2 - Actions, their timing and the stakeholders in the period 2030 - 2040

ACTION	PREP.	IMPL.	NEC.	PROGRESS	IMPLEMENTER	INFLUENCER	USER
Interoperability	2020	2030	2035	None	EU	Manufacturers/ TSOs/ OFTOs	TSOs/ OFTOs
Offshore DCCB deployment	2028	2030	2035	None	Manufacturers		TSOs/ OFTOs
Small bidding zones	2035	2039	2040	Final	Governments/ NRAs	TSOs/ OFTOs	TSOs/ SOs
Decommissioning	2035	2035	2040	None	Governments/ NRAs	Manufacturers	Manufacturers/ TSOs/ OFTOs
Supply chain	2030	2030	2035	None	Governments	Manufacturers	Governments
Joint support schemes	2025	2030	2035	None	Governments/ NRAs	TSOs/ OFTOs	OWF developers
Aligned permitting pilot project	2025	2030	2035	None	Governments/ NRAs	TSOs/ OFTOs	OWF developers
Remuneration regulation pilot project	2025	2030	2035	None	Governments/ NRAs	TSOs/ OFTOs	OWF developers

THE PERIOD 2040 – 2050

By this point, the offshore HVDC grid should be well established. As complexity of the grid increases it may be an opportunity to explore the benefits of connecting smaller meshed grids to create a highly complex meshed grid. However, PROMOTioN analysis found that these grids will be very difficult to properly control. A potential application of DC/DC converters will therefore then have to be explored, which can be used to control the DC power flow. Without this control, the natural flow of DC power could be different than expected which could lead to potentially dangerous situations. Due to the current Technology Readiness Level (TRL) of DC/DC converters, research into this technology will have to begin from 2020 onward, all the way up to this period. See Table 3.

Table 3 - Actions, their timing and the stakeholders in the period 2040 - 2050

ACTION	PREP.	IMPL.	NEC.	PROGRESS	IMPLEMENTER	INFLUENCER	USER
DC/DC converters	2025	2045	2050	None	Manufacturers		TSOs/ OFTOs

THE PERIOD 2020 – 2050

Some recommendations will run from the start up to the end of the analysed period. This includes the interaction with flexibility, which has not been researched within PROMOTioN. Therefore, this should be further explored throughout the grid lifetime. Additionally, the protection strategy may be further researched and adjusted throughout the entire lifetime of the grid, as all kinds of protection strategies may be applied in portions of the grid. Refer to Table 4.

Table 4 - Actions, their timing and the stakeholders in the period 2020 - 2050

ACTION	PREP.	IMPL.	NEC.	PROGRESS	IMPLEMENTER	INFLUENCER	USER
Interaction with flexibility	2020	2020	2050	None	Manufacturers		TSOs/ OFTOs
Protection strategy	2020	2020	2050	Ongoing	TSOs/ OFTOs	Manufacturers	TSOs/ OFTOs

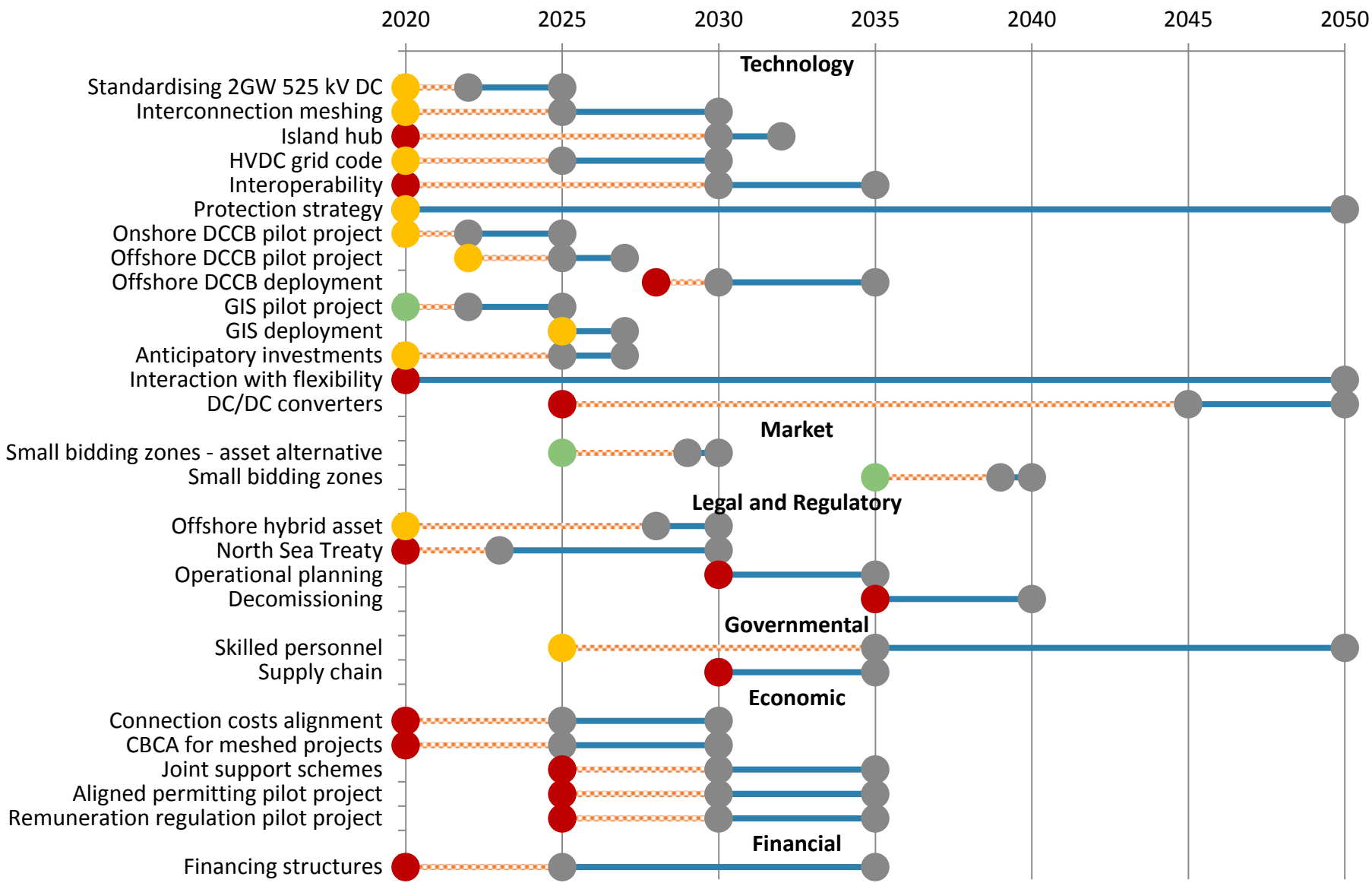


Figure 2 - Overview of the recommendations and their timings

DOCUMENT STRUCTURE AND PROVIDING FEEDBACK

This report is the culmination of over four years of research into the technical, legal, economic and financial requirements for constructing a Meshed Offshore Grid in the North Seas. It summarises the findings from the wider PROMOTioN (Progress in Meshed HVDC Offshore Transmission Networks) project and presents a roadmap for delivering transmission networks in the North Sea cost effectively. This document is split into seven chapters followed by appendices:

1. Introduction
2. Cost-Benefit Analysis of a Multi-Terminal Offshore Grid
3. 2020- 2025: Current development plans
4. Development of a Meshed Offshore Grid
5. Stakeholder actions for the development of a Meshed Offshore Grid
6. Conclusion
7. **Error! Reference source not found.**
8. Appendices:
    - Appendix I – Grid Concepts
    - Appendix II – Multi-Terminal Offshore Grid Components
    - Appendix III - Assumptions and boundaries of analysis
    - Appendix IV - Stakeholders
    - Appendix V – Offshore wind market structures
    - Appendix VI – Grant Agreement project objectives

Chapters 2, 3 and 4 (CBA Results, Short Term Projects and the Roadmap) present the main recommendations that are key to delivering offshore wind in the North Sea and the rationale behind the development plan. This includes:

- A summary of the CBA outcomes, describing the relative costs and benefits of different topologies and how this impacts the deployment plans for offshore wind.
- An overview of the current offshore wind deployment plans, including upcoming meshed or hybrid asset projects. This is followed by details of the grid topology to 2050 under each of the four grid concepts.
- Details of the technical developments and decisions still required to deliver the 2050 topologies and recommendations on how to deliver these.
- Recommendations and rationale for the legal, regulatory and financial frameworks for a meshed grid and who should deliver these recommendations.

- A discussion on different market models for a meshed offshore system and how we transition from current market models.

Chapter 5 summarises the actions required to implement the recommendations and the stakeholders responsible for implementing them. These are split into short and long term actions.

Chapter 6 concludes the document and highlights the most important recommendations.

DOCUMENT UPDATED AND HOW TO PROVIDE FEEDBACK

This deliverable is a 'Draft' Deployment Plan feedback on it from others is welcomed. Feedback on this document will then be integrated into the final Deployment Plan, which is Deliverable 12.4.

In addition, 12.4 will contain a more detailed Chapter 5 (Stakeholder Actions).

1 INTRODUCTION

By the end of 2019, 22 GW of offshore wind capacity was installed across Europe with much of this capacity concentrated in the North Seas [1] (North Sea, Irish Sea, English Channel, Skagerrak Strait and Kattegat Bay). This is a 10-fold increase over the last decade, and continues to grow, with a clear pipeline of projects stretching into the 2020s across the North Seas countries [2]. Currently, most of this wind generation is transmitted to shore using point-to-point High Voltage Alternating Current (HVAC) connections. However, as the distance to shore increases, the need to use High Voltage Direct Current (HVDC) connections rises. This is especially true when point-to-point networks develop into meshed networks.

The PROMOTioN project (Progress on Meshed HVDC Offshore Transmission Networks), is a program that has advanced the key technologies required to build, control and protect meshed HVDC transmission grids; namely control systems, DC circuit breakers, HVDC protection systems and Gas Insulated Switchgear (GIS) [3]. This technology development has included a mixture of theoretical modelling and simulation, and laboratory testing of scaled or full-size prototype technologies. Routes for standardising these technologies and ensuring interoperability have also been considered. Figure 1-1 shows the impact of this research and testing on the Technology Readiness Level (TRL) of the technologies examined within PROMOTioN. Figure 1-2 summarises the work package (WP) structure.

Alongside the technical work packages, work package 7 developed legal & regulatory, economic, financial, government and market solutions to accelerate the development of an HVDC Meshed Offshore Grid (MOG) in the North Seas.

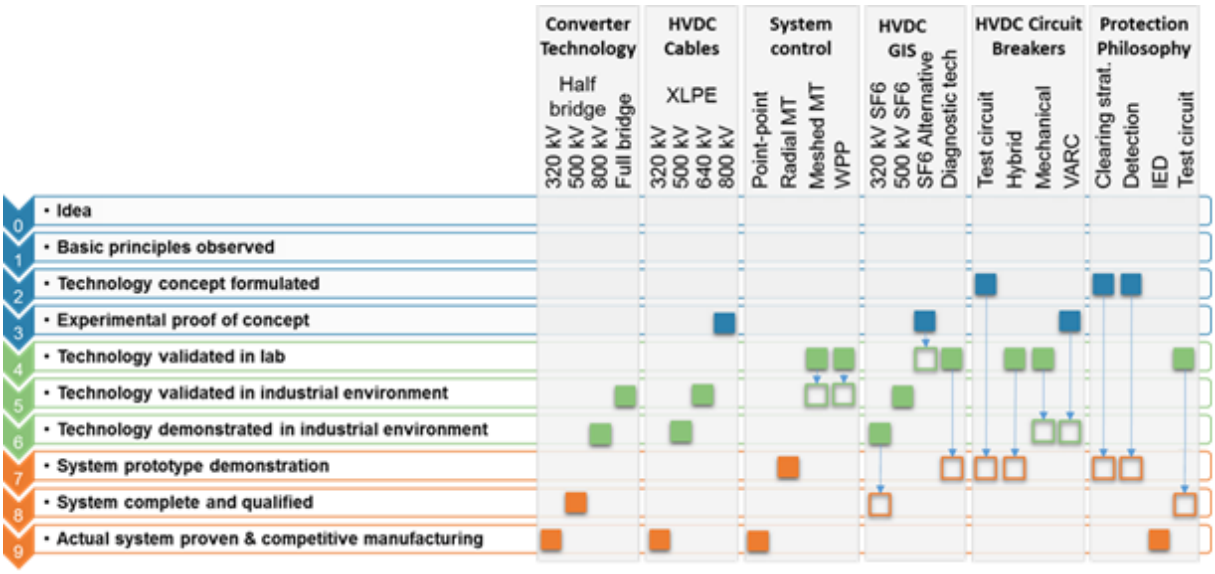


Figure 1-1 Technologies and their Technology Readiness Level before and after PROMOTioN, with arrows and open boxes indicating progress made within PROMOTioN.

[3] Diode Rectifier Units, a type of converter, were initially studied in a separate Work Package within PROMOTioN, but this Work Package was terminated before the end of the project. Instead, it was chosen to start a Work Package on Gas Insulated Switchgear. Simulation work done with DRU characteristics does indicate this as a plausible conversion solution in some applications

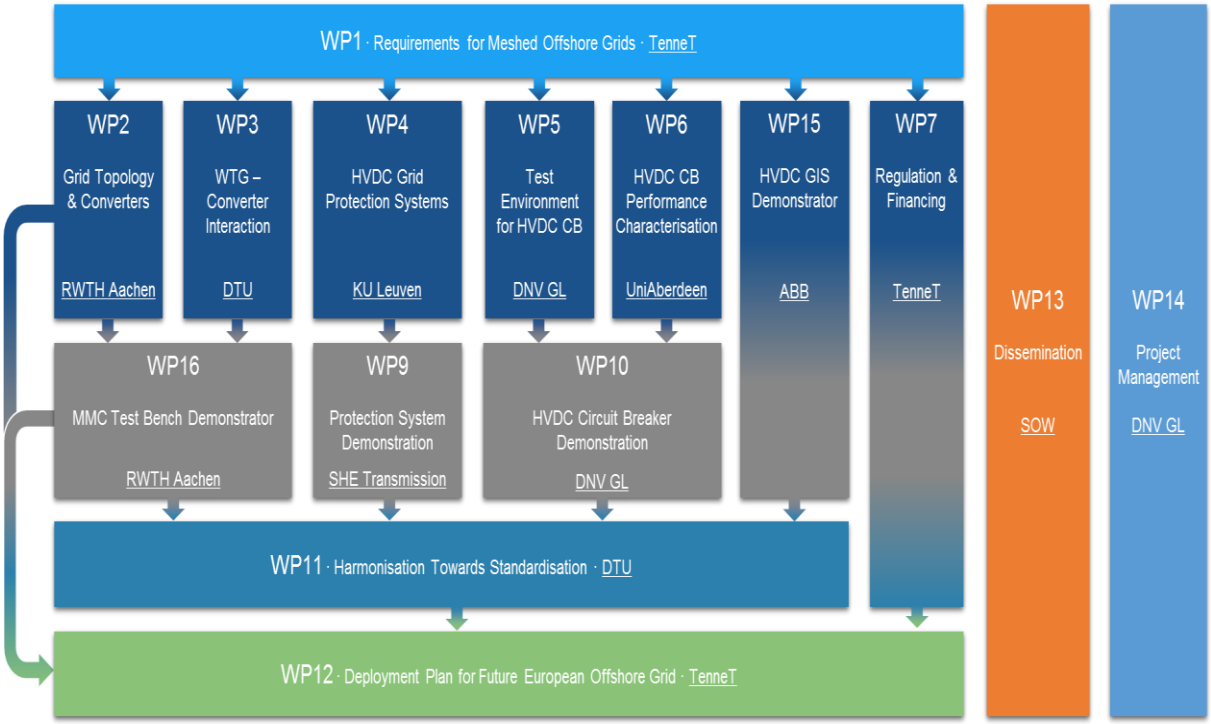


Figure 1-2 - PROMOTioN Project Structure as of November 2018

This deliverable is part of WP12, which has sought to consolidate findings from across the PROMOTioN project in order to develop a deployment plan for a Meshed Offshore Grid.

1.1 OVERVIEW OF WORK PACKAGE 12

The goal of WP12 is to summarise the results of the PROMOTioN project and give practical and executable advice to the European Commission (EC) to advance the deployment of a MOG, including advice on what immediate next steps can be taken. This is the third of five reports from this work package and is a draft deployment plan for a Meshed Offshore Grid. It follows Deliverable 12.1 which was summary of the work completed within the PROMOTioN project at the time of writing [21 December 2017], and Deliverable 12.2 which details the outputs of the CBA carried out on four different offshore grid designs (concepts) under alternative offshore wind deployment scenarios. The outcomes of this CBA fed into this deployment plan along with recommendations from other work packages. Deliverables 12.1 and 12.2 are described in more detail below, along with a summary of remaining WP12 deliverables.

1.1.1 DELIVERABLE 12.1 - SUMMARY OF THE WORK DONE

Deliverable 12.1 contains an overview of the intermediate conclusions of each WP. It also introduces the Grid Development Concepts that were developed to describe how a HVDC MOG may evolve. These concepts each describe distinct ways in which a grid may develop, varying in complexity and level of international coordination (more information on these Concepts in 1.2.2 below). Deliverable 12.1 provides a clear overview of the work done in PROMOTioN and the barriers that had been identified by the WPs.

1.1.2 DELIVERABLE 12.2 - SCENARIO AND CONCEPT TOPOLOGY CREATION

In order to properly compare the virtues of each of the proposed grid concepts, detailed proposals for each are provided. Deliverable 12.2 describes where the windfarms may be located, and forecasts offshore wind

generation. It also describes how the topologies are derived and specifies a grid architecture for each option, at five-year intervals up to 2050. These concept-scenarios (topologies) are presented as guidelines and their aim is to set specific examples of possible reality (see Appendix I for further details). The document also explains the underlying assumptions, design choices and reasoning behind these topologies. Finally, Deliverable 12.2 utilises a modified ENTSO-E methodology for CBA to determine the costs and benefits of each of the proposed concepts compared to a business-as-usual scenario. These results have informed the recommendations in this document.

1.1.3 DELIVERABLE 12.3 - THE PRELIMINARY DEPLOYMENT PLAN

This document (Deliverable 12.3) presents a deployment plan on how to steer the construction of a multi-terminal offshore grid. For each of the grid concepts developed, the development of the network is shown in 5-year time steps for three different levels of offshore wind deployment. The necessary economic, financial, legal & regulatory, government, market and technical requirements at each time step are set out, and recommendations on how to deliver these are proposed. Stakeholders responsible for delivering the actions are identified.

1.1.4 DELIVERABLE 12.4 - FINAL DEPLOYMENT PLAN

This document will conclude the work that has been done in the WP12 and present the final recommendations for the deployment plan of the HVDC MOG. The recommendations will incorporate additional research done on costs and benefits, some sensitivity analysis on key assumptions and feedback on Deliverable 12.3 drawn from stakeholder consultations.

1.1.5 DELIVERABLE 12.5 - PUBLICATION OF THE FINAL DEPLOYMENT PLAN

The final deployment plan will be published after consultation with stakeholders.

1.2 APPROACH OF WORK PACKAGE 12

This section provides an introduction to the deployment scenarios and grid concepts used to build the grid topologies and provides an overview of the CBA methodology (developed in WP7) used to compare these. Each of these topics is described in more detail in subsequent chapters.

1.2.1 OFFSHORE WIND DEPLOYMENT SCENARIOS

Development of offshore wind energy is growing quickly but the exact pace at which development will take place is dependent on various factors including the economic case for offshore wind, environmental constraints and capacity in the supply chain. To account for this uncertainty, the PROMOTioN project's CBA will examine three different deployment scenarios for the North Seas for 2050 - Low (90GW), Medium (150GW) and High (205 GW). Each scenario is developed in five year time steps. These scenarios were extrapolated from the ENTSO-E TYNDP forecasts to 2040.

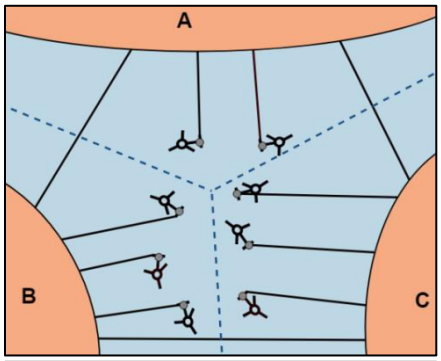
The table below depicts an overview of the three deployment scenarios. These high level figures were allocated to individual countries and then translated into specific projects. The grid was then developed according to the specific grid concepts (see below), to yield the topologies that were used in the CBA in Deliverable 12.2. Further detail on how these scenarios were derived and allocated to different locations is provided in Chapter 3 of Deliverable 12.2.

Table 1-1: Overview of three deployment scenarios used in PROMOTioN (values in GW)

	2020	2025	2030	2035	2040	2045	2050
High	19.6	40.0	65.0	95.0	125.0	160.0	205.0
Medium	19.6	34.0	49.0	67.0	90.0	115.0	150.0
Low	19.6	27.0	36.0	47.0	58.0	72.0	90.0

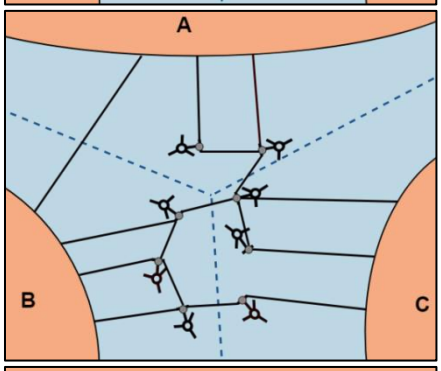
1.2.2 GRID DEVELOPMENT CONCEPTS

The PROMOTioN project has developed four grid concepts to present the different ways in which the offshore transmission grid could develop out to 2050. Figure 1-3 below, provides a simplified representation of each concept.



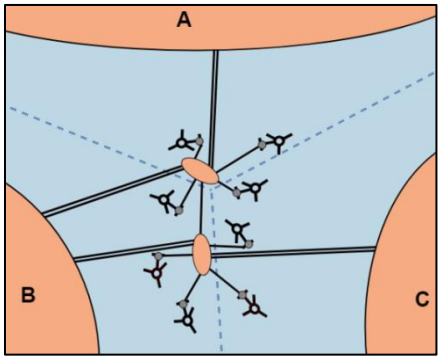
Business as usual (BAU)

The current method of connecting OWFs to the onshore grid is by radial connections. Various wind parks are either directly connected to shore with DC lines or grouped into clusters, and then connected to shore. For short distances AC lines can be used. Connections between the electricity grid of different countries are made by dedicated lines, interconnectors (such as BritNed/NEMO link).



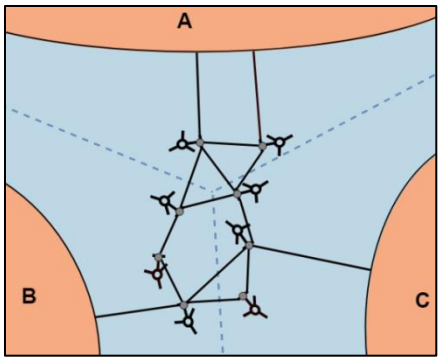
National Distributed (NAT)

The offshore grid for each country is designed to evacuate all offshore generated wind energy generated in its own Exclusive Economic Zone (EEZ) to its onshore grid. Interconnection may be facilitated by connecting offshore hubs of different countries together; these would only be used in periods of low wind energy generation. NAT assumes low coordination and cooperation between countries, thereby potentially establishing a sub-optimal grid.



European Centralised (HUB)

OWFs are connected to large offshore hubs. These central locations might host a significant capacity (e.g. 30 GW) and may, therefore, merit the construction of artificial islands as opposed to the commonly used offshore platforms. The central hubs will be connected with large power corridors to the onshore grids, thereby creating significant amounts of interconnection in periods of low wind.



European Distributed (EUR)

International focus on grid development is assumed. EUR blurs the borders between North Seas countries and instead focusses on an optimal evacuation of wind energy generation. This also means that the national offshore grid of countries may not be able to evacuate the wind energy generated in their EEZ, thereby requiring some generation to be exported directly to other countries.

Figure 1-3 - Illustration of the different Concepts

These Grid Development Concepts were described in more detail in Appendix I and in Deliverable 12.2.

1.2.3 COST-BENEFIT ANALYSIS

Deliverable 12.2 used a CBA methodology developed in WP7 to assess the societal costs and benefits of each grid concept under each of the deployment scenarios. Further details on the methodology and results can be found in deliverables 7.11 and 12.2 respectively.

2 COST-BENEFIT ANALYSIS OF A MULTI-TERMINAL OFFSHORE GRID

2.1 COST-BENEFIT ANALYSIS RESULTS

A CBA was carried out in Deliverable 12.2 of the different concepts that were imposed onto the scenarios, as was described in the previous section. A CBA is an assessment of the costs and benefits of an investment decision in order to assess the welfare change attributable to it [3] and a tool used to judge the advantages and disadvantages of an investment decision (or series of investment decisions). The CBA methodology used in the PROMOTioN project is detailed in *Deliverable 7.11 - Cost-benefit analysis methodology for offshore grids*. The methodology has been designed such that it can be applied to all grid concepts in a consistent way, enabling a direct comparison. The results of the scores of each concept on the Key Performance Indicators (KPIs) of the CBA can be found in Table 2-1 and Table 2-2 below. For more insight in the analyses that lead to these results, refer to Deliverable 12.2.

In terms of capital expenditure (CAPEX) and operational expenditure (OPEX), the HUB concept provides the best alternative to the BAU, but only where the artificial islands are large enough to replace a significant amount of platforms. Especially the NAT and EUR concepts require larger investments, although these then do provide more available transfer capacity in the grid. This has an impact on the benefits. Due to the increased interconnection capacity, the NAT and EUR concepts have a larger influence on the socio-economic welfare.

As for the qualified KPIs in Table 2-2, the concepts each carry different benefits. For example, the HUB concept shows medium flexibility (B7), low security (B8) and low resilience (B9). It impacts more environmental factors (S1) than the other concepts, but in turn has low social impacts (S2). The NAT concept, on the other hand, has high impact on flexibility (B7), medium security (B8) and high resilience (B9). Conversely, it impacts less environmental factors (S1), but higher social impacts (S2) than the HUB concept. Any choice for a specific concept may therefore not be merely a judgment of costs and benefits but rather a trade-off of specific values an offshore grid may deliver. An offshore grid developed according to the HUB philosophy, for example, may be the most financially attractive and least risky option, but its benefits might not be as prominent as in the EUR concept.

Table 2-1 - Outcome of the quantitative Key Performance Indicators of the CBA carried out in PROMOTioN

KEY PERFORMANCE INDICATOR	CONCEPT	COST OR BENEFIT			UNIT
		High scenario	Central scenario	Low scenario	
C1: CAPEX	*BAU*	229.00	151.90	91.60	bn€
	NAT	239.70	156.50	91.40	
	HUB	207.80	144.30	91.30	
	EUR	246.20	164.80	92.40	
C2: OPEX	*BAU*	63.00	41.90	27.00	bn€
	NAT	65.80	43.20	26.50	
	HUB	59.10	41.90	27.60	
	EUR	68.50	46.70	27.10	
B1: Socio-economic welfare	*BAU*	0	*	*	bn€
	NAT	10.37	*	*	

KEY PERFORMANCE INDICATOR	CONCEPT	COST OR BENEFIT			UNIT
	HUB	0.07	*	*	
	EUR	7.62	*	*	
B2: Renewable Energy Sources (RES) integration	*BAU*	0	*	*	MWh
	NAT	16,700,000	*	*	
	HUB	15,600,000	*	*	
	EUR	-47,200,000	*	*	
B3: Variation in CO_2-emissions	*BAU*	0	*	*	t
	NAT	41,000,000	*	*	
	HUB	22,700,000	*	*	
	EUR	6,300,000	*	*	
B6: Security of supply: Adequacy to meet demand	*BAU*	0	*	*	GWh
	NAT	143,000	*	*	
	HUB	143,000	*	*	
	EUR	127,000	*	*	

* Will be evaluated in an update to Deliverable 12.2

Table 2-2 - Outcome of the qualitative Key Performance Indicators of the CBA carried out in PROMOTioN

KEY PERFORMANCE INDICATOR	CONCEPT	COST OR BENEFIT	IMPACT
B7: Security of supply: System flexibility	*BAU*	Increased flexibility in operation and levelling out uncertainties and variations in wind production.	None
	NAT		High
	HUB		Medium
	EUR		Medium
B8: Security of supply: System stability (security)	*BAU*	Improved power oscillation damping, provision of synthetic inertia and black-start (assisting) capabilities and reactive power compensation and active voltage stability support	High
	NAT		Medium
	HUB		Low
	EUR		Medium
B9: Security of supply: resilience	*BAU*	Increase in resilience of power system	High
	NAT		High
	HUB		Low
	EUR		High
S1: Environmental impacts	*BAU*	Effects of the concepts are described according to their impact on environmental factors.	Vibration, wind effects and spreading of non-indigenous species
	NAT		Vibration, wind effects and spreading of non-indigenous species
	HUB		Noise, EMFs, artificial substrate, sediment dynamics, wave actions and operational discharges
	EUR		Vibration, wind effects and spreading of non-indigenous species
S2: Social impacts	*BAU*	Space consumption, visual	High

	NAT	contamination and negative health effects	Medium/low
	HUB		Low
	EUR		Medium/low
S3: Other	All	Possibility of gradual development	High
	All	Support for European industry	High
	All	Geopolitical advantages	High
	All	Increased European integration	High

From the analyses made in Deliverable 12.2, conclusion and recommendations are further incorporated in Chapter 4 below. Note that these recommendations are in the light of PROMOTioN's analysis, in which several specific assumptions are made and a number of aspects aspects are left out of scope. These assumptions are further detailed in Appendix III.

2.2 KEY TECHNO-ECONOMIC REASONS FOR THE DEVELOPMENT OF THE OFFSHORE GRID

In the first stages of HVDC grid development OWFs are constructed close to the shore and basic radial, point-to-point connections are dominant. Thus, meshing is more focused on national waters and cooperation between countries is low. In later stages of development, meshed topologies are expected to become dominant and OWFs will be installed far from shore. A MOG will be formed by interconnecting OWFs with different onshore systems. The MOG would be able to combine the evacuation of offshore wind energy and facilitate the exchange of power between different countries. In order to do so, the design and build of a MOG is a complex process that has to fulfil many requirements. The requirements that have to be met are presented in section 2.2.1. If these requirements are met, the implementation of a MOG has many advantages that will be listed in the following section 2.2.2.

2.2.1 REQUIREMENTS FOR THE DESIGN OF THE MESHED OFFSHORE GRID

The operation of a MOG and the widespread grid is complicated and requires the commercial availability of key technologies and an adequate regulatory framework. A major challenge is the control and the protection of the grid, due to the high level of connectivity. Thus, designing and developing an appropriate protection system for the meshed HVDC offshore grid is challenged by more significant topics such as need of proper models, need of interoperability, need of considering future extension possibilities, need of considering the right choice of converter configuration, need of proper design criteria, lack of sufficient standardisation and Grid Codes and, finally, a lack of mature components for some important parts of the protection system.

Besides, in order to successfully finish the project, barriers for MOG development have to be overcome. WP1 (Deliverable 1.1) has identified requirements that have to be considered for a successful finish of the project. Deliverable 1.1 recognised 124 quantitative conditions and all these conditions must be fulfilled. The requirements are grouped by interface or system in the following order (number of requirements identified in brackets):

1. Functional system requirements (5)
2. MOG – Onshore AC (39)
3. MOG – Offshore Generation (34)
4. MOG – Offshore Consumption (1)
5. MOG Operation (15)
6. Non-functional requirements (e.g. legal or financial requirements) (30)

Figure 2-1 summarises how each group of requirements are connected to the PROMOTioN WPs. More specified details regarding these requirements are described in Deliverable 1.1.

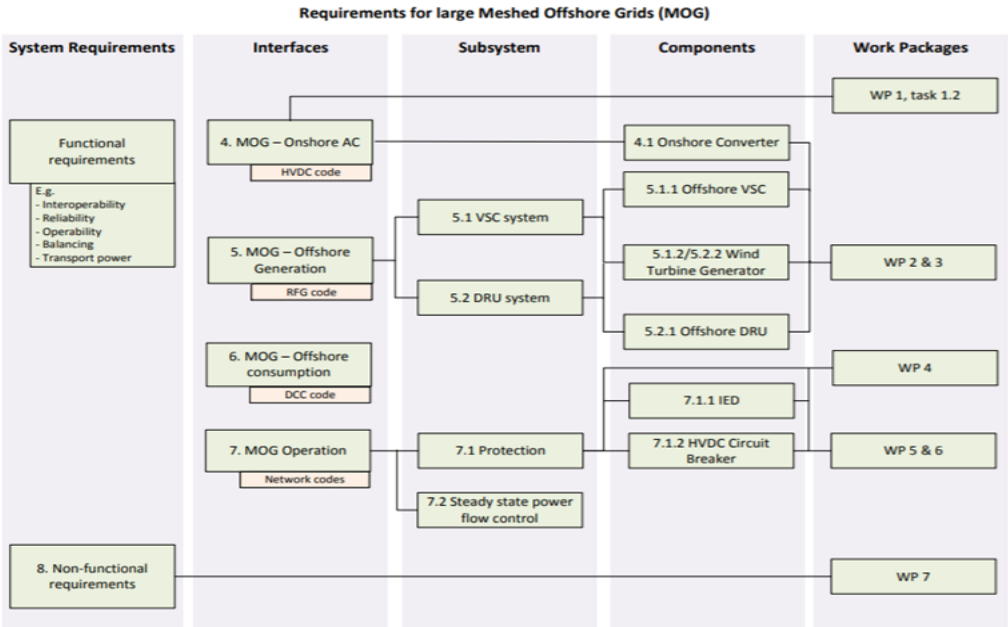


Figure 2-1 - Requirements for large Meshed Offshore Grids.

2.2.2 MESHED OFFSHORE GRID ADVANTAGES

Development and successful implementation of a MOG can significantly change future power systems and may have an important influence on energy markets. A MOG has a great list of advantages that can be grouped into four categories that are presented on Figure 2-2. Detailed description of every category of advantages is presented below.

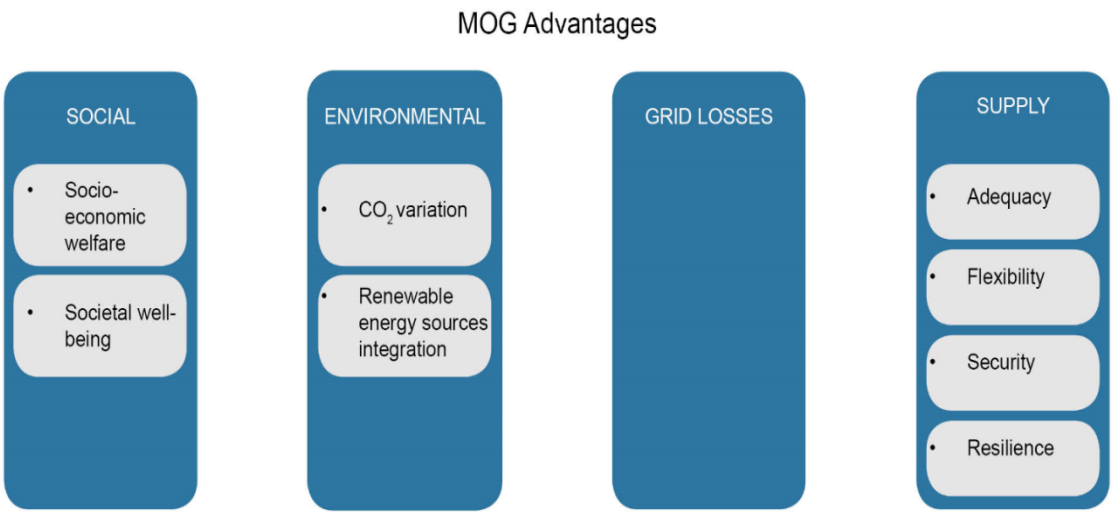


Figure 2-2 Key advantages of MOG implementation

2.2.2.1 SOCIAL

SOCIO-ECONOMIC WELFARE

A number of beneficial factors of a MOG impact the socio-economic welfare:

- A MOG can potentially provide a big amount of interconnection capacity, connecting different European countries using power links with higher capacities than is available today. The consequence of this will be

price convergence (through market coupling). Price convergence directly results in the socio-economic welfare, which consists of the sum of consumer surplus, producer surplus, and – in the case of limited interconnection capacity – congestion rent.

- A MOG can result in less congestion management, which consequentially means lower redispatch costs.
- A MOG can increase demand opportunity due to the availability of a bigger market for the adaptation of the wind power without having a very strong converse correlation between the wind parks. This is different than the current – national – approach where the power generation of wind parks is usually quite strongly correlated. The progress in demand opportunity would hence lead to fewer moments in time where the marginal wind infeed price approaches 0 €/MWh. This leads to better profit margins – an incentive for wind farm development – as well as to lower risks associated with wind farm development.
- A meshed grid topology in which wind evacuation transmission assets are combined with interconnection use will be cheaper than a pure radial solution with separate point-to-point interconnectors. This difference in costs is a consequence of fewer transmission assets required.
- The MOG will result in an increase in the capacity credit of the offshore wind production. This is a consequence of the fact that MOG encompasses a larger geographic area, meaning that the correlation between the output of one wind park and another wind park will decrease.

SOCIETAL WELL BEING

The MOG development can result in benefits to society which are not fully gained by the indicators on socio-economic welfare. For instance, the increased integration of RES can result in the replacement of conventional fossil fuel generation, which have other benefits like the improvement of local air quality what has a direct consequence in increasing societal well-being and living conditions.

2.2.2.2 ENVIRONMENTAL

A MOG can enable the enhanced integration of RES into the power system. This has a long list of pros that can be divided into the one connected to RES integration and CO_2 variation.

RENEWABLE ENERGY SOURCES INTEGRATION

Several factors impact the integration of RES:

- The benefit of MOG implementation with regards to the integration of RES is that MOG can equip alternative pathing for wind evacuation. Even without applying a strict N-1 security criterion, a meshed grid can provide some redundancy for wind evacuation. Considering the fact that availability of the offshore grid is not perfect, there is a significant benefit to having an alternative, additional path for wind electricity available. This increases the amount of renewable energy integrated into the system and saves costs in compensation for the downtime of the grid as well.
- Having a MOG can increase the redundancy and hence the net availability of the offshore grid. Even though this benefit alone may not be sizeable enough to motivate the development of a meshed grid, it still can be an important potential benefit to the development of the grid.
- Application of a MOG in connection to the integration of RES can lead to enhanced access to storage because of more interconnection capacity. With an increasing share of variable RES in the power system, the need for storage increases in the future. Storage can help to balance the variable production of renewable energy and can help to match this supply with consumer demand.

CO_2 VARIATION

The MOG can result in a net decrease of CO_2-emissions. The most important impact on the amount of CO_2 (equivalent) greenhouse gas emissions will come from the development of RES.

- MOG would increase coupling between different time zones, leading to an improved spread of total system peak load and thus a reduction of the maximum system peak load ('load-flattening'). The peak of power demand frequently occurs in the evening. If regions have different time zones, this means that the peak load of region A will not coincide with the peak load of region B. Thanks to the interconnection between these time zones, the problem of satisfying these peak loads can be spread over multiple countries. This results in a decrease in CO_2-emissions since the variable peak load is usually supplied by gas turbines. A reduction in the peak load would involve a reduction in the amount of gas-generated power required, thus a decrease in CO_2-emissions.
- The meshed grid can lead to improved utilization of the potential of different RES within the European system. A better-interconnected grid allows countries to concentrate on their specific equivalent advantages with respect to different RES. For instance, a country that is very suitable for high penetration of PV electricity generation could make use of wind energy generated in other countries or offshore throughout the night using a MOG (and vice versa). Thanks to this, the countries would not need to depend on conventional power plants to provide power throughout times in which their domestic renewable energy generation supply is not big enough to satisfy demand. By implementing this, a meshed grid decreases overall CO_2-emissions.
- The MOG results in an increase in market integration and can thus also lead to more efficient production plants. Less efficient (in monetary terms) generation plants (conventional power plants with high variable costs e.g. gas power plants) will be pushed out of the market by economic forces because of improved market integration. This move towards more efficient generation plants would also decrease the total amount of CO_2-emissions.
- A meshed grid can lead to more efficient use of wind generation facilities because the curtailment of wind production could be decreased. Curtailment of (offshore) wind infeed is essential when the grid is not capable of transporting all the intended electricity production to the load centres. Since the rejection of power (curtailment) also leads to disturbances in the power quality, a decrease in curtailment can further improve the power quality of the system. Besides, this results in lower costs, higher CO_2-emissions savings and a better business case for OWFs, resulting in better incentives for offshore wind developments.

2.2.2.3 GRID LOSSES

The meshed HVDC grid can reduce grid losses in the onshore HVAC grid. This strictly depends on the specific interaction between the HVDC offshore and the HVAC onshore system. For instance, HVDC provides better controllability of power flows which empower system operation strategies which optimise towards the lowest amount of grid losses possible. As a consequence, an HVDC MOG could decrease the amount of loop flows in the onshore grid because power flows can be actively steered. Reducing the occurrence or size of these loop flows could decrease grid losses. Nonetheless, the exact effects of the HVDC MOG on the onshore grid losses are still unclear until different operational strategies would be modelled.

2.2.2.4 SUPPLY

System security of supply depends on the system adequacy, flexibility, security, and resilience. The adequacy of the power system is related to the existence of sufficient facilities within the system to supply demand. It estimates if the system is appropriately equipped to supply demand, also with (unplanned) outages of transmission equipment. In order to do so, the sufficient generation capacity and adequate distribution and transmission networks with satisfactory capacity are needed. Another aspect that refers to energy supply is the

flexibility of the system. System flexibility deals with quick changes in energy output from variable RES. Finally, system resilience defines how resilient the system is against large disturbances such as natural disasters or terrorist attacks. Below the advantages are presented that implementation of a MOG can provide in order to improve the reliability of system supply.

SECURITY OF SUPPLY: ADEQUACY

The MOG can considerably improve the adequacy of the system compared to radial wind evacuation connections. Since a meshed grid can create alternative paths for power evacuation, an outage of the primary connection to shore would have not or would have a smaller effect compared to the radial approach.

SECURITY OF SUPPLY: FLEXIBILITY

Impacts of the MOG on the flexibility of the grid are plentiful:

- The MOG will have a positive impact on the protection of the onshore landscape and can reduce costs by alleviating the need for onshore grid reinforcement. This is because the development of the offshore grid could replace the need for onshore grid reinforcements since new interconnection capacity would be created without interruption in the onshore landscape.
- The meshed grid would provide larger flexibility in operation than a radial grid topology. This is due to the fact that a meshed topology has more alternative paths available for the required power flows. This is an advantage for the system operation since a broader set of alternatives offers better operation opportunities. It would engage an increase in the degrees of freedom for system operators. This increases the desired flexibility in dealing with outages, congestion management, balancing and maintenance.
- HVDC MOG improves the controllability (and hence flexibility) of the grid. HVDC technologies allow power flows to be steered actively, hence offering more freedom for system operators. HVDC systems can behave like grid-forming components rather than grid-following components. System operators would be able to use HVDC technologies to support or alleviate the onshore HVAC power system when necessary.
- The MOG can connect a bigger capacity of variable RES together, increasing the amount of power production deviations connected to each other in a system with a larger geographical spread. This means that the deviations will become interdependent and less random, providing the meshed grid to level out a large portion of these deviations.

SECURITY OF SUPPLY: SECURITY

Also numerous factors impact the security of the system:

- The MOG can provide black-start (assisting) capability to the onshore grid. A black-start facility is needed to be able to start up the power grid after a black-out; the black-start facility has to provide electricity to other power plants in order to start up. Such black-start capabilities are generally provided by conventional fossil fuel power plants. An HVDC MOG can as well provide the necessary electricity to simplify the start of other power plants and in that way provide black-start assisting capabilities. Compared to a radial topology, a MOG can increase the reliability of this service because of an increased capacity credit of offshore wind. Hence, a meshed grid can reliably offer this service, whereas a radially developed offshore wind grid would be less capable of doing so.
- A MOG can offer active voltage stability support and large-scale reactive power compensation. This is due to the large-scale application of HVDC converters in a MOG. The power supply characteristics of HVDC converters can be easily adjusted and HVDC converters offer a great amount of flexibility in doing so. This would not only improve power quality and help strengthen weaker grids, but it avoids investments in

equipment that would have otherwise been necessary for these functions as well. For instance, the reactive power compensation capability of HVDC converters causes the need for shunt capacitor banks void, avoiding investments in that type of equipment.

SUPPLY-RESILIENCE

The MOG would involve a high degree of decentralisation of interconnection capacity and decentralization of offshore wind power evacuation. This decentralization makes the overall grid less vulnerable to natural disasters and terrorist threats. It also provides the capability of grid islanding, in which different parts of the grid can be operated independently. Non-functioning, destroyed parts of the grid can be isolated while other parts of the grid keep functioning. A highly centralised offshore grid concept that consist of radial connections would be more vulnerable to natural disasters and terrorist threats since the impact of such disturbances would be more significant than in case of the meshed grid concept.

3 2020- 2025: CURRENT DEVELOPMENT PLANS

Today, the majority of developed OWFs are near shore and radially connected. However the losses associated with moving electricity greater distances have been recognised and projects are increasingly looking to use HVDC technology to reduce these losses. HVDC platforms are being installed, especially in the German sector of the North Seas; the 9 Borwin (1, 2, and 3), Dolwin (1, 2, and 3), Helwin (1 and 2) and Sylwin platforms are all HVDC. HVDC platforms are also planned or in construction in Dutch, Belgian and United Kingdom (UK) waters. There are also a number of HVDC interconnection cables exchanging power between several European countries.

Near-term HVDC projects present the opportunity to demonstrate the HVDC technologies being developed in PROMOTioN, and which will be needed for multi-terminal HVDC projects; DCCBs, DC GIS and control and protection systems. They also present an opportunity to test legal, regulatory and market arrangements for multi-terminal HVDC projects. Planned projects are identified in a separate PROMOTioN project which could be modified to test HVDC technologies, in particular focusing on the South West Link (in Sweden), Ijmuiden Ver WindConnector and the Bornholm Energy Island projects.

3.1 PLANNED HVDC PROJECTS

The ENTSO-E TYNDP for 2018 identifies planned offshore transmission assets out to 2040 (Figure 3-1). This version of the plan indicates that there will be increased use of HVDC for interconnection. Some development of hybrid connections or dual-purpose links connecting OWFs to shore for energy evacuation is anticipated. Also, as distances increase, the first signs of offshore platforms becoming "mini-hubs", collecting generation from multiple OWFs, is observed, however these are not multi-terminal.

However, with the focus on interconnection, there is little detail in TYNDP of how the majority of offshore wind will be connected to the shore, despite the fact that offshore energy generation capacity in the region is anticipated to be 125GW in 2040 according to its Global Climate Action Scenario [4].

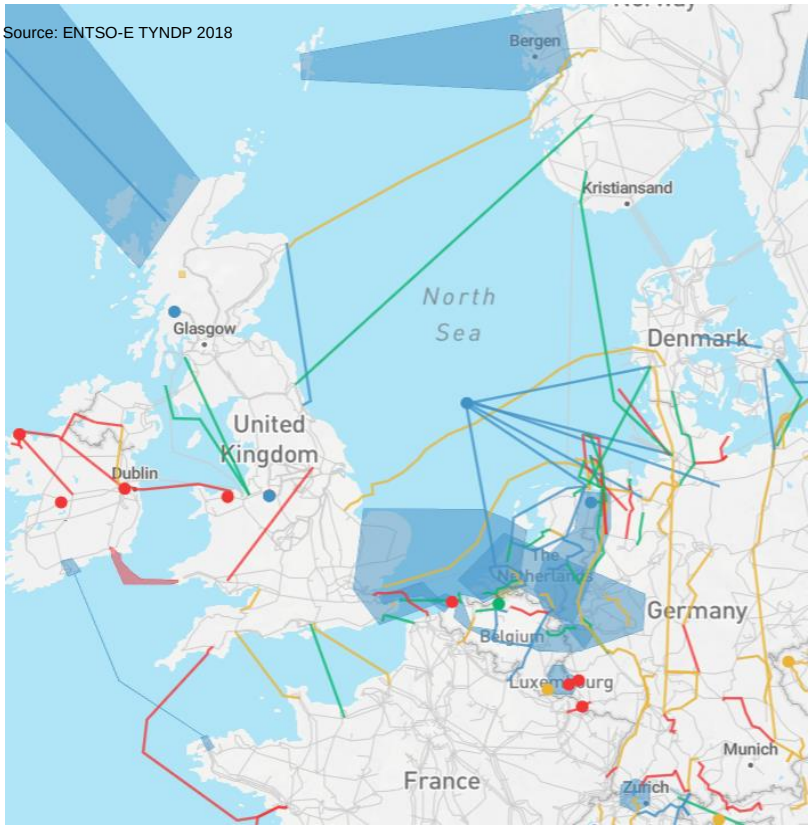


Figure 3-1 ENTSO-E Map of proposed projects in the Northern Seas

3.2 ATTITUDES TO MULTI-TERMINAL HVDC GRID PROJECTS

Stakeholder engagement and the literature reviewed by PROMOTioN consortium partners have concluded that there is currently a lack of ambition to deliver multi-terminal HVDC projects. The few proposals for HVDC projects are based mainly on point-to-point connections, avoiding the possibility of creating multi-terminal connections. The reasons quoted to PROMOTioN partners for avoiding multi-terminal HVDC projects are:

1. **Too risky**. TSO management and Regulators are risk averse; TSOs are unwilling and unsure how to defend the use of HVDC CBs and protection in an untested environment towards the regulator.
2. **Too expensive**. The capital costs are anticipated to be too high. In particular, the space that is required for HVDC, multi-terminal project is large resulting in materially larger offshore platforms.
3. **The Legal & Regulatory environment is not yet ready for multi-purpose projects**. Workarounds can facilitate a unique solution but this may encounter objections.
4. **Too complex to manage stakeholder views**. Most of the hybrid projects involve two or more countries as such the negotiation process requires agreement from at least 6 parties: the 2 TSOs, 2 Regulators, at least 2 Owners/Government, OWFs, etc. Each has its own interests and concerns. Also, the suppliers need to consider a multi-terminal option, and where more contractors involved, interoperability.
5. **There is no immediate technical need.** The projects are currently quite simple, whereby the targeted results can almost be reached without the use of new technology.
6. **Planning processes are not designed for complex projects.** The current planning process is between designed for individual and uncoordinated projects that are delivered as standalone projects. This is because of limitations in connections to the onshore grid, when compared to the size of the projects, the non-technical barriers that we describe further in this document and the short planning horizon for projects – this does not make a more strategic approach easy to deliver.

7. **Lack of technical expertise**. There is also insufficient knowledge and experience within the TSOs to consider HVDC multi-terminal connections. The only existing experience is on land in China.

3.3 PROMOTION INVOLVEMENT IN SHORT TERM PROJECTS

The PROMOTioN project has developed and demonstrated (in laboratory conditions) solutions for the key technical barriers to multi-terminal HVDC projects (DCCBs and GIS). However, due to the reasons listed above and the lack of operational experience, it is unlikely that any potential project developer will be willing or able to accept the risk associated with trialling several of these solutions at once. Hence, a more likely deployment plan for these solutions consists of trialling them one-by-one in existing, planned or newly built projects prior to combining them in multi-terminal HVDC offshore projects.

As a result, PROMOTioN has, within the remit of the Grant Agreement[4], evaluated the technical feasibility, costs and benefits, risks and the legal and regulatory problems of projects which may be suitable for testing new HVDC equipment. There are three projects considered, described below.

3.3.1 SOUTHWEST LINK – HANSA POWER BRIDGE DC CONNECTION.

SouthWest Link and Hansa Power Bridge are two DC cables which find one of their ends landing at the same substation in Hurva, Sweden, see Figure 3-2. The former is a backbone DC cable connecting two Swedish bidding zones, the latter is an interconnector running to Germany. They are based on similar technology and will most likely use the same DC operating voltage. This raises the question whether connecting these links on the DC side into a multi-terminal connection would be beneficial. The link can be realised as a project extension without significantly altering existing plans. With the proposed DC connection power fed through the node in Hurva will not have to pass through two converter stations, which is the case otherwise. This implies power loss savings, which translate into very significant savings on operating cost over the lifetime of the installations. Likely, these savings could make the installation of the proposed link profitable. Such a development would bring lots of experience in designing, deploying and operating multi-terminal DC (MTDC) links in Europe, which is currently lacking. Obtaining such experience will be necessary for further deployment of MTDC infrastructure in Europe, including meshed HVDC networks and offshore MTDC nodes. A key component to ensure operation of this link is DCCB.

[4] Under the Grant Agreement we are committed to progressing HVDC meshed offshore grids. In order to advance the technology to a TRL where industrial prototypes or industrialization begins

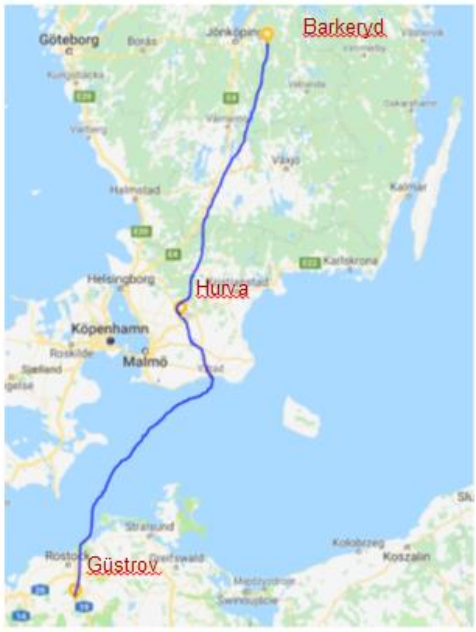


Figure 3-2 Geographic routing of the two links

3.3.2 BORNHOLM ENERGY ISLAND

Bornholm Island is Danish island located in the Baltic Sea in between Denmark, Sweden, Germany and Poland. It is proposed to use this island as an offshore hub for connecting up to 5 GW of offshore wind. The island can be further interconnected to Denmark, Poland, Germany and Sweden thus allowing for higher rates of cable utilization. The proposal is to introduce hybrid assets in order to ensure economically optimal wind evacuation combined with the interconnection of Baltic countries. Within PROMOTioN, the study will study focus on the most attractive bidding zone arrangements, technical hub configurations and ownership models. There is a large potential on saving costs by designing the size of connections to mainland in such a way that the utilization is maximised, at the same time without the need of curtailing offshore wind farms connected to island. The local AC network of Bornholm, as well as AC networks of adjacent countries, may benefit from the increasing stability and security of supply.

3.3.3 IJMUIDEN VER WINDCONNECTOR PROJECT

The Ijmuiden Ver WindConnector project suggests building a DC cable running from a Dutch OWF either directly to the UK, or to another OWF in the British EEZ. This will increase the interconnection capacity between the two countries, at the same time allowing for more ways of evacuating wind energy to where it is mostly needed. The cost of the infrastructure will significantly decrease as there will not be a need to build a separate DC cable between the coasts of two countries. The PROMOTioN project will study what are the potential impacts on the security of the connected networks, how can DCCBs be applied to ensure sufficient level of protection, and what is economically the most optimal bidding zone configuration.

3.4 ASSESSING THE VALUE OF HVDC TECHNOLOGIES TO SHORT TERM PROJECTS

Figure 3-3 describes how amendments to existing and planned projects, in order to test new HVDC technologies, could be evaluated. The objective is that the adjusted net benefit (calculated as Net Present Value of Benefits less Operating Costs less Capital Investment) is greater than or at least close to the original proposal net benefit.

The social benefits may either be calculated quantitatively or be related to demanded standards of performance required of a functioning meshed grid (e.g. black start; load balancing; protection, etc.).

Figure 3-3 Project evaluation metodology.

Another consideration to be taken is related to the non-financial trajectory (Figure 3-4). A (meshed) HVDC project may require additional permits for assets that are likely to cross national EEZ borders, or the regulatory environment for hybrid assets may need to be clarified. Specific case by case evaluation needs to be made.

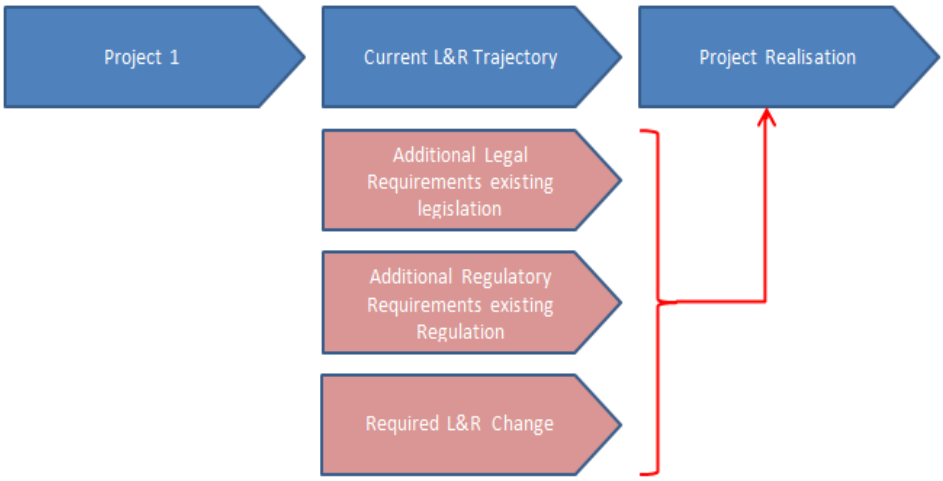


Figure 3-4 Modified Project Administration

3.5 SUMMARY

The projects described above, give Europe the opportunity to test different albeit simple elements of the technology in an industrial situation. In applying the technology in these relatively simple situations albeit of progressive complexity, the technology is demonstrated, experience and learning around the technology in an industrial setting is gained, potentially reduce short term costs/increase benefits, the European development of HVDC hardware is raised, and ultimately the development of the offshore energy sector is advanced. These projects are also an opportunity to test the legal and regulatory environment around the potential for different market models or the application of the principles behind a hybrid asset.

In PROMOTioN, a step beyond this selection of planned and existing projects is made to describe, using modelling outputs developed during WP12, how a multi-terminal grid could develop efficiently out to 2050 to evacuate offshore wind power. This highlights that there need to be more multi-terminal projects active by 2040 than are currently planned and that an overall vision and co-ordination are necessary for future projects to build on those developed in the near term. This is a step further than today where it is seen that each project – whether by European TSOs or by OFTOs in the UK - is designed and built as a single standalone project and scaled to serve a specific solution.

4 DEVELOPMENT OF A MESHED OFFSHORE GRID

As described in the introduction, PROMOTioN has examined how offshore wind power could be evacuated most efficiently under four different grid concepts – Business as Usual (BAU), National Distributed (NAT), European Distributed (EUR), and European Centralised (HUB). This chapter first describes the development of each of the concepts out to 2050 in 5-year segments, based on modelling outputs. It then sets out the technical, legal, regulatory, financial, market and governmental recommendations to deliver an efficient multi-terminal offshore network.

4.1 GRID DEVELOPMENT

The grid developments are described in the following sections and figures. To better highlight the differences between each concept, the development of each of the concepts are displayed only for the sections of the grid that are typical to the concept in the high scenario. This is because the high scenario best expresses the differences between the concepts. Each representation therefore shows the same OWFs, all connected according to the philosophies for each concept. In doing so, representations of each concept are displayed in each period, showing the different design philosophies impacting a select amount of OWFs.

As the BAU concept does not represent a distinctive development, this concept is not displayed. For each of the other concepts, any OWF that is radially connected to the grid in all three concepts are also not displayed, as these do not represent the design philosophy of these different concepts. Additionally, any OWF that is first connected to an island in the HUB concept before being brought to shore but is radially connected in the NAT and EUR concept is also not displayed. This is because effectively, this OWF is radially connected to shore, only the support structure is different. For each period a description is made of the changes compared to the preceding period. A slight indication of the impacts and whether or not it is necessary to implement certain recommendations are also given.

4.1.1 2020 - 2025

See Figure 4-1. At the start of the period the concepts already differ significantly from each other. For example, in the NAT concept a Dutch OWF is connected to the Dutch shore, as is dictated by the concept design philosophy. The same OWF is connected to the UK through another UK OWF in the EUR concept, minimising the total length of cable.

Noticeable also is anticipatory investment as a result of central planning. In the NAT and EUR concepts, an OWF is built in Belgium that will be connected with a hybrid interconnector by 2030 (depicted in the next section). This entails anticipatory investments necessary to connect this cable.

Four islands are already beginning construction in the HUB concept in this period. In reality, these islands are likely to still be in the planning and design phases in 2025.

Technically, these concepts do not pose much of a challenge. There is some interconnection between platforms, which may be the most challenging configuration to construct. The meshed situations that these create do not pose any problems on the protection side as the rating of connected cable remains below the reference incidents of the connected areas.

As much of the offshore grid is still similar to the current offshore grid, with the exceptions of the hybrid interconnection, many current regulations may still apply in this period. However, as a minimum, bilateral agreements will be required to agree the regulatory framework for the hybrid interconnector between the Netherlands and the UK (NAT Concept), and/or the support scheme for the connection of a German OWF that is only connected to Denmark (EUR Concept). These situations could not be managed under 'business as usual' regulation.

The integration of these bilateral agreements into a future regulatory regime for the MOG would be much smoother if at this stage the key principles of MOG regulation had been agreed, including the definition of an offshore hybrid asset and agreement on how regulatory decisions will be made across the North Seas.

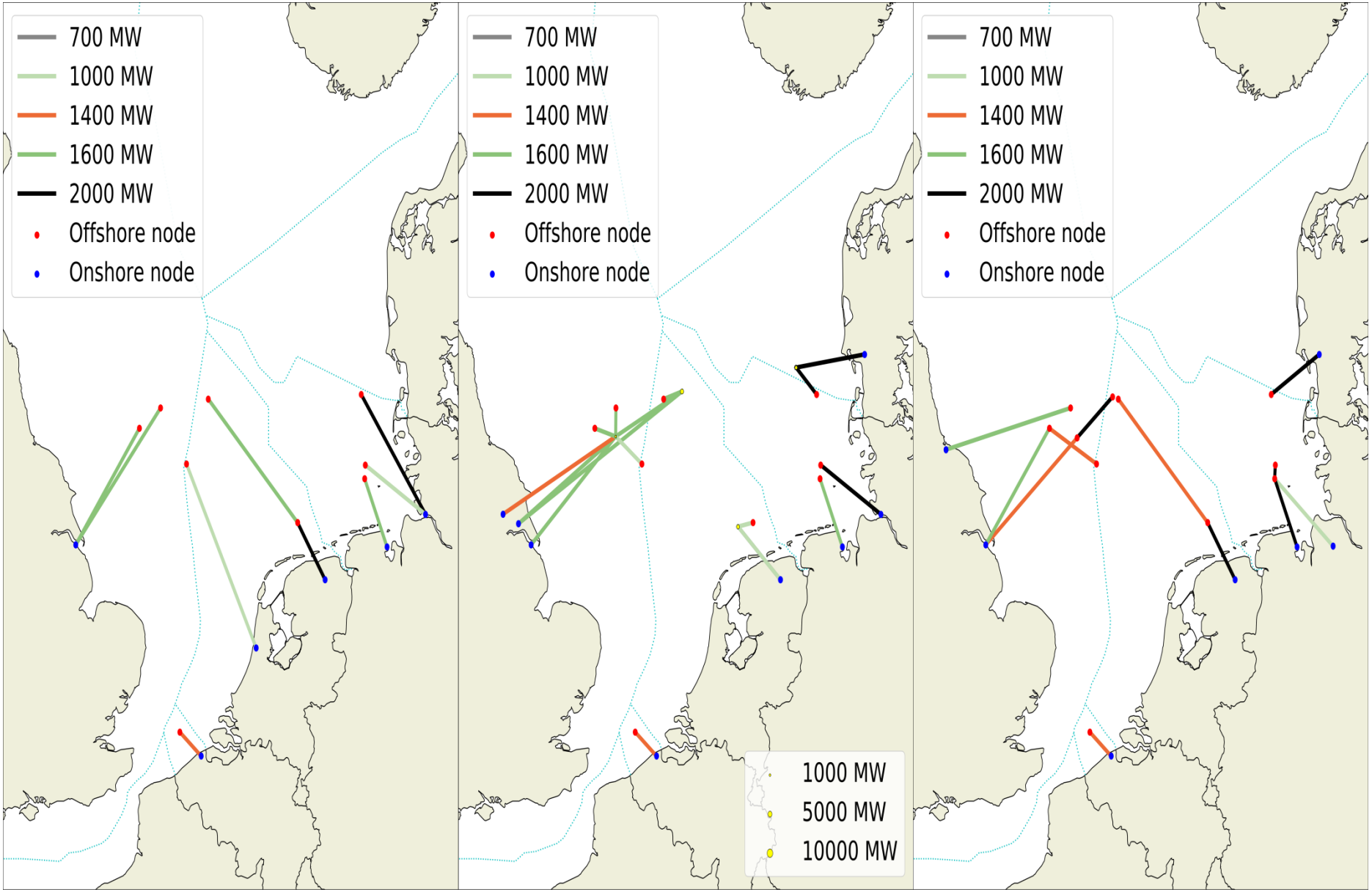


Figure 4-1 - From left to right: NAT, HUB and EUR concept representations of the North Seas by 2025

4.1.2 2025 - 2030

The situation in 2030 does not differ much from the one in 2025. Several connections are established in a similar fashion as in the previous period. However, in the NAT concept a structure is constructed that, at first sight, seems to necessitate the use of DCCBs. However, due to the clustering of the NAT and EUR concept some OWFs will have to be weakly interconnected with each other. There is a possibility to do so in AC, because of the distance between within these clusters. The use of DCCBs may therefore be omitted, which is the assumption made within the project (for the purposes of the CBA).

The construction of islands may be a more tangible reality in this period, which is deemed optimal in the HUB concept. All six islands are in the early stages of construction. Some of these already grow to a significant size in later periods, as many OWFs may already be connected to these islands. Some interconnection between the islands is also established, thereby creating large interconnected structures. Similarly, however, the islands are considered to be built with protection on the AC-side, thereby not necessitating the use of DCCBs yet.

In order to have achieved this cost-effectively, improvements to the CBA and CBCA methodology should have been implemented and used during the planning phase. Where large construction projects are underway (particularly island hubs), this implies that (i) agreements between the regulator(s) and transmissions owner on remunerating anticipatory investment have been agreed; and (ii) there is a sufficiently certain pipeline of projects to make island construction worthwhile.

The HUB concept includes a grid connected to three countries. This will require a trilateral agreement which could form the basis of a broader regulatory approach to multi-terminal grid regulation and the market model for OWFs connected to a multi-terminal grid.

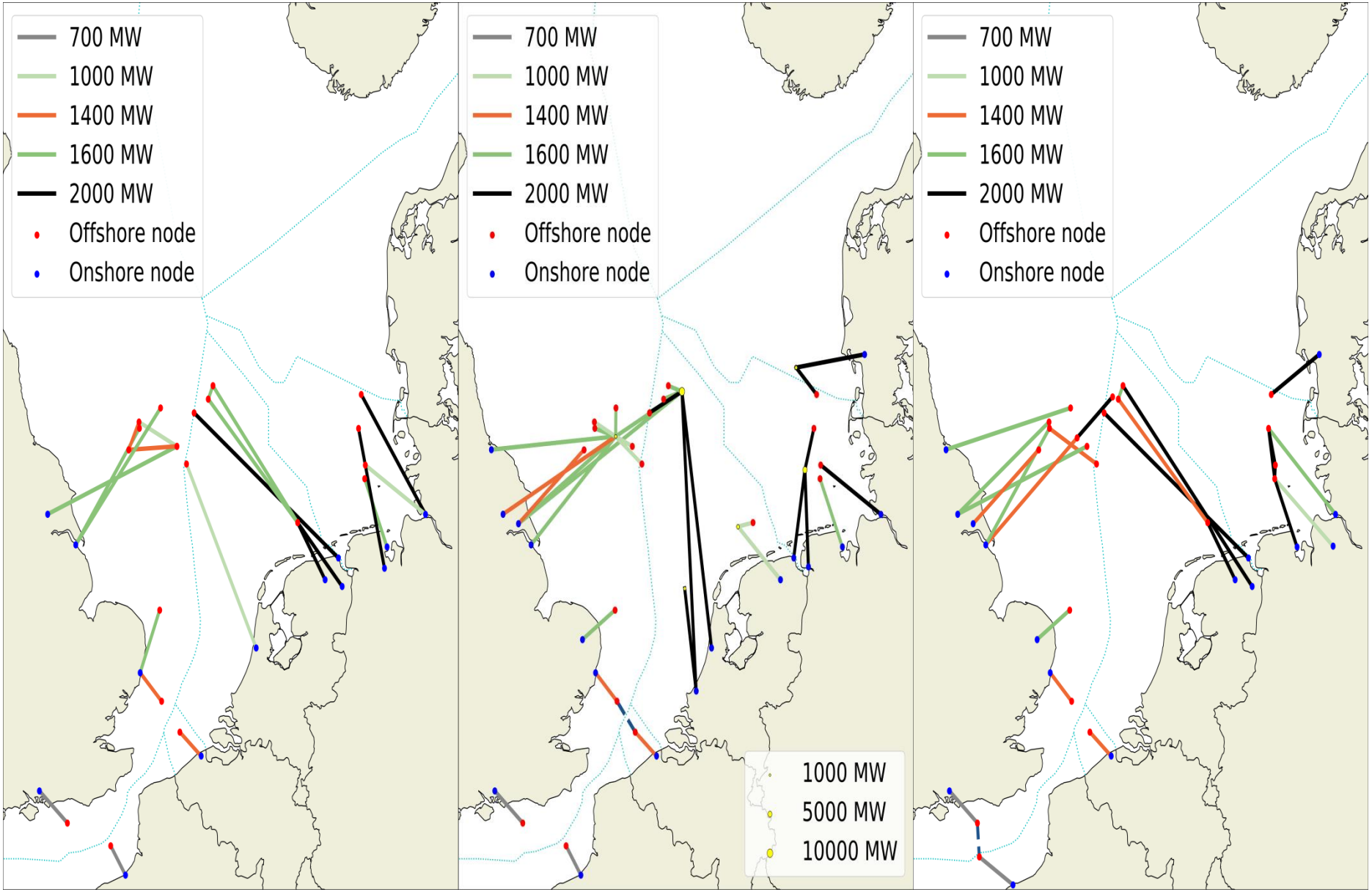


Figure 4-2 - From left to right: NAT, HUB and EUR concept representations of the North Seas by 2030

4.1.3 2030 - 2035

Again in 2035 the concepts seem similar to the previous period. There is hardly any change in the meshed situations in the NAT and EUR concept and also the HUB concept only seems to slightly grow the islands by adding more capacity. Although there certainly is an increase in generation, this generation is connected through point-to-point configurations or connected to the islands and therefore is not shown in Figure 4-3.

Similarly, the concepts do not pose any difficult new challenges. Due to the near stand-still in meshed development, this period might give room to implement regulations destined for the entire meshed offshore grid, slowly replacing the bilateral agreements. This gives time to evaluate these instruments and improve them where necessary. This period also gives room to correctly plan for the coming periods, in which the meshing within the offshore grid may again get a boost. However, as mentioned earlier, the extent to which the principles of MOG regulation can be agreed sooner, the easier it will be to incorporate bilateral agreements into a wider regulatory structure. If this doesn't happen, there is a risk that the bilateral agreements cannot be brought into a wider MOG regulatory regime and these assets will continue to be managed separately. This may result in a sub-optimal build out of the network from a cost and technical perspective.

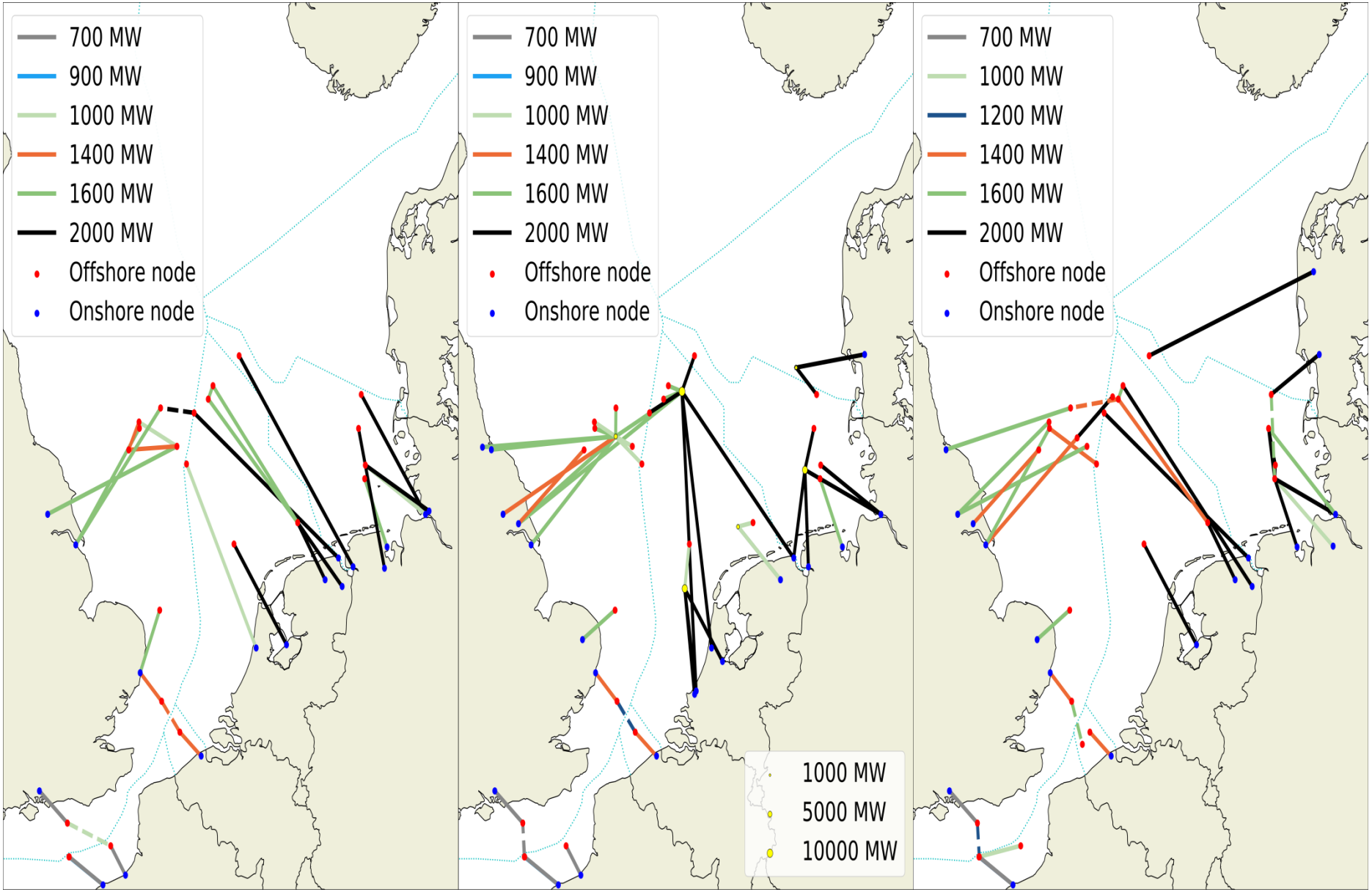


Figure 4-3 - From left to right: NAT, HUB and EUR concept representations of the North Seas by 2035

4.1.4 2035 - 2040

By 2040, the situation changes drastically in the NAT and EUR concept. Where the meshing was quite limited in earlier periods, especially the NAT concept now shows complex structures that are interconnected within and between countries. A total of four countries are directly connected through one structure the grid: Denmark, Germany, Netherlands and the UK. The EUR concept, although not as much meshed as the NAT concept, shows a significant amount of OWFs that are constructed in one country but connected to another. Several OWFs are also interlinked, also creating more complex situations.

In the HUB concept, on the other hand, the situation remains relatively similar to the previous periods. The highest amount of complexity is added by a cable constructed between two Dutch islands. As each of the Dutch islands is now connected to each other, a ring-like structure is established in the HUB concept, thereby creating a large amount of possible alternative pathing.

Due to the added complexity in the NAT concept, it is proposed to have a protection system in place that incorporates the use of DCCBs. This will significantly increase the costs of this concept compared to the other concepts, but this should be worth the increase in flexibility and trade.

In both the NAT and HUB concept, the flows become more unpredictable and might flow towards different countries than in which the OWF is located. The same happens in the EUR concept, although these flows are anticipated due to the direct connections between OWFs and other countries. This particular characteristic of the offshore grids, however, entails that differences in regulations between the North Seas' states may prove difficult to overcome. Simple bilateral or trilateral agreements may become difficult to negotiate, with many of these necessary to allow for proper functioning of the grid. It is therefore strongly suggested that the non-technical recommendations proposed further in this chapter are in place by 2040. These recommendations intend to create a level playing field for the entire MOG, thereby making separate agreements unnecessary. In this period, all recommendations that are essential for the functioning of the MOG should have been agreed and carried out, including:

- The establishment of a mixed partial agreement setting out the cooperation and management arrangements for the MOG across North Seas countries
- Introduction of a definition of ‘offshore hybrid asset’
- Identification of regulatory decision-making structure (recommended in PROMOTioN to be cooperation between NRAs)
- Clarity on grid ownership structures
- Clarity on grid connection and access processes and costs for OWFs
- Clarity on market model for OWF revenue and allocation of any remaining support scheme costs
- Clarity on transmission owner revenue, incentives and risks.
- Clarity on grid operation.

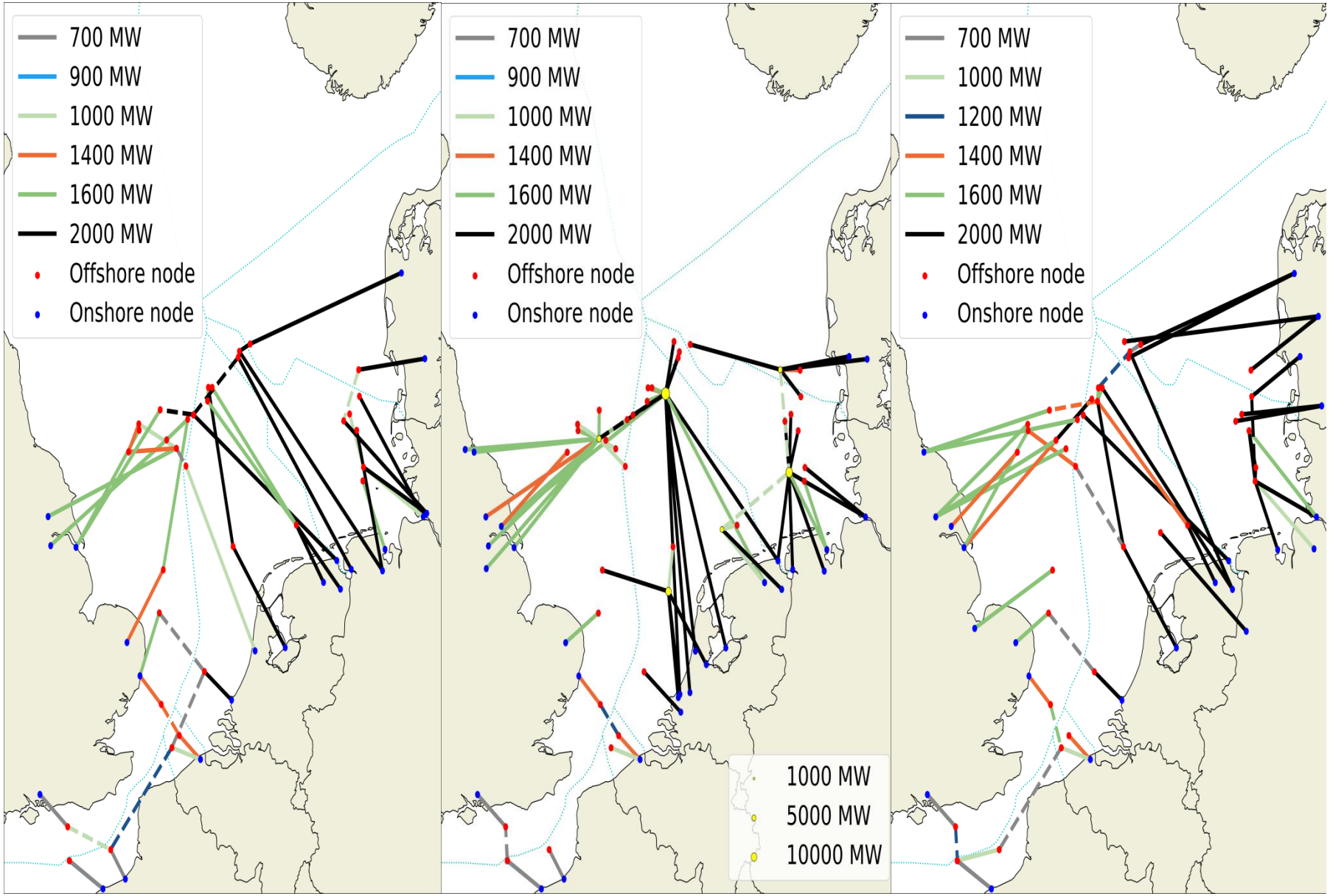


Figure 4-4 - From left to right: NAT, HUB and EUR concept representations of the North Seas by 2040

4.1.5 2040 - 2045

The complexity continues to increase in the concepts, with the NAT concept adding Norway to its countries that are directly connected through a single structure. This structure is also further meshed in German waters, increasing its complexity. Similarly, in the HUB concept, a Dutch island is now also connected to a German island, thereby adding in another ring-like structure into the grid. In the EUR concept, more meshed configurations are established, also adding to its complexity in operation.

All essential recommendations should have been carried out at this point, leaving no additional recommendations to be implemented. This period again gives way for evaluation and reflection of the recommendations. As such, it can be evaluated if these have the desired effects and whether or not these should be adapted. For example, close cooperation of NRAs in regulating the MOG could develop into a de-facto North Seas regulator.

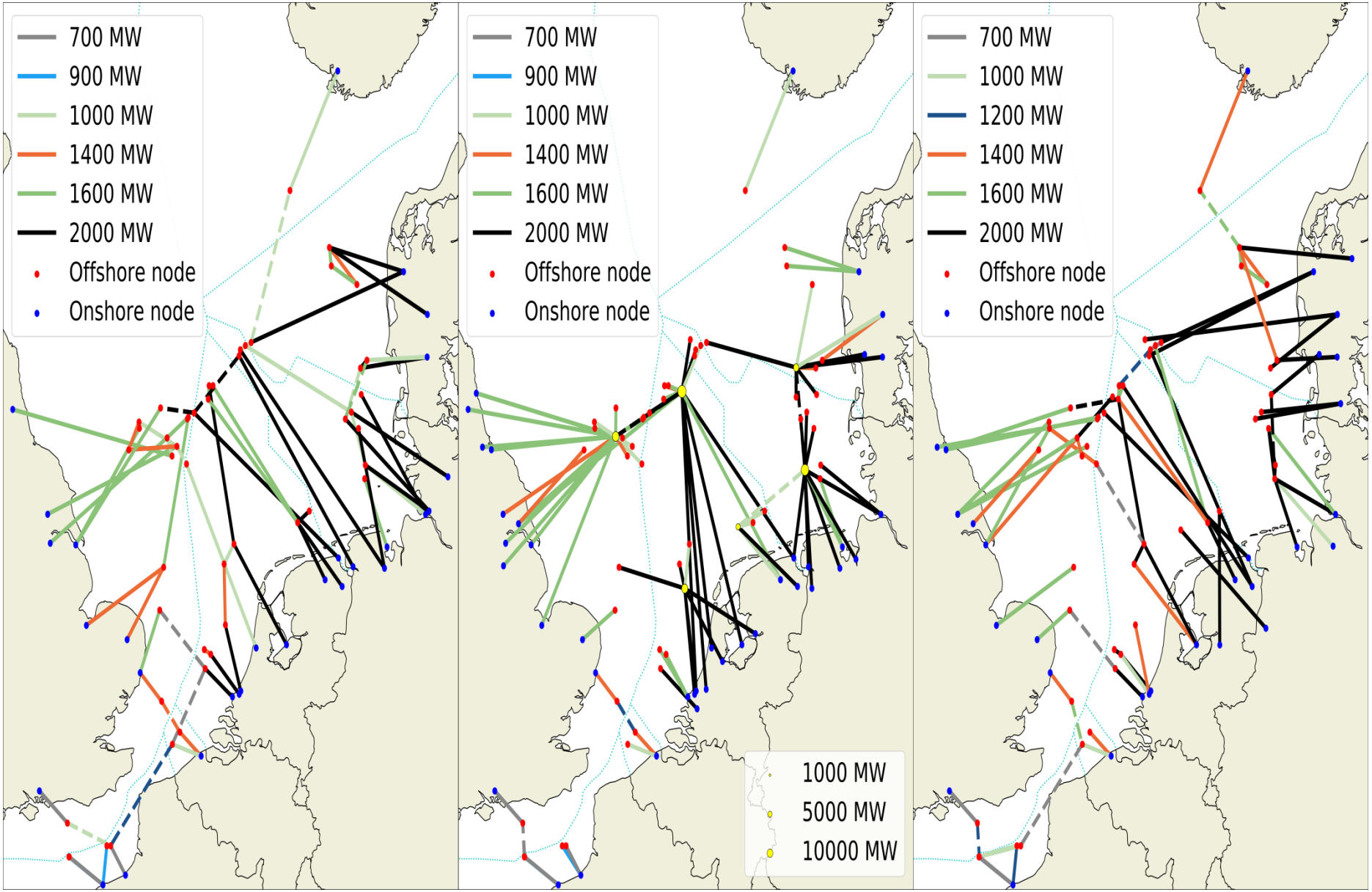


Figure 4-5 - From left to right: NAT, HUB and EUR concept representations of the North Seas by 2045

4.1.6 2045 - 2050

By 2050, the MOG is fully formed. The three different concepts illustrate that different routes can be taken to export the same amount of wind generation. The highest amount of hybrid interconnection, and thus meshing, can be found in the EUR concept. Especially around the area in the centre of the North Sea is where most of the OWFs are interconnected within and between countries. This will make the EUR concept the most expensive concept to construct, mostly due to its platform extensions, its need for DCCBs and the additional cable length.

The HUB concept establishes some more interconnection between the countries by 2050, thereby creating a large interconnected structure of islands. This allows for alternative pathing and thus a lot of flexibility in the system. Due to the possibility to connect the converters on the islands in AC, the islands do not require an expensive protection system in contrast with the NAT and EUR concepts.

The EUR concept, although showing similarities to the NAT concept, does not interconnect as many OWFs. This may be partially attributed to the fact that there is less need for interconnection: the OWFs are directly connected to the country already if there is a need to deliver the energy to that country.

From a regulatory point of view, the broad principles of the MOG should now be well established and embedded. By now, some of the earlier wind farms will have reached the point of decommissioning and some hybrid assets may continue as interconnectors. Recommendations on decommissioning which should have been included in the planning permission for wind farms should now be implemented.

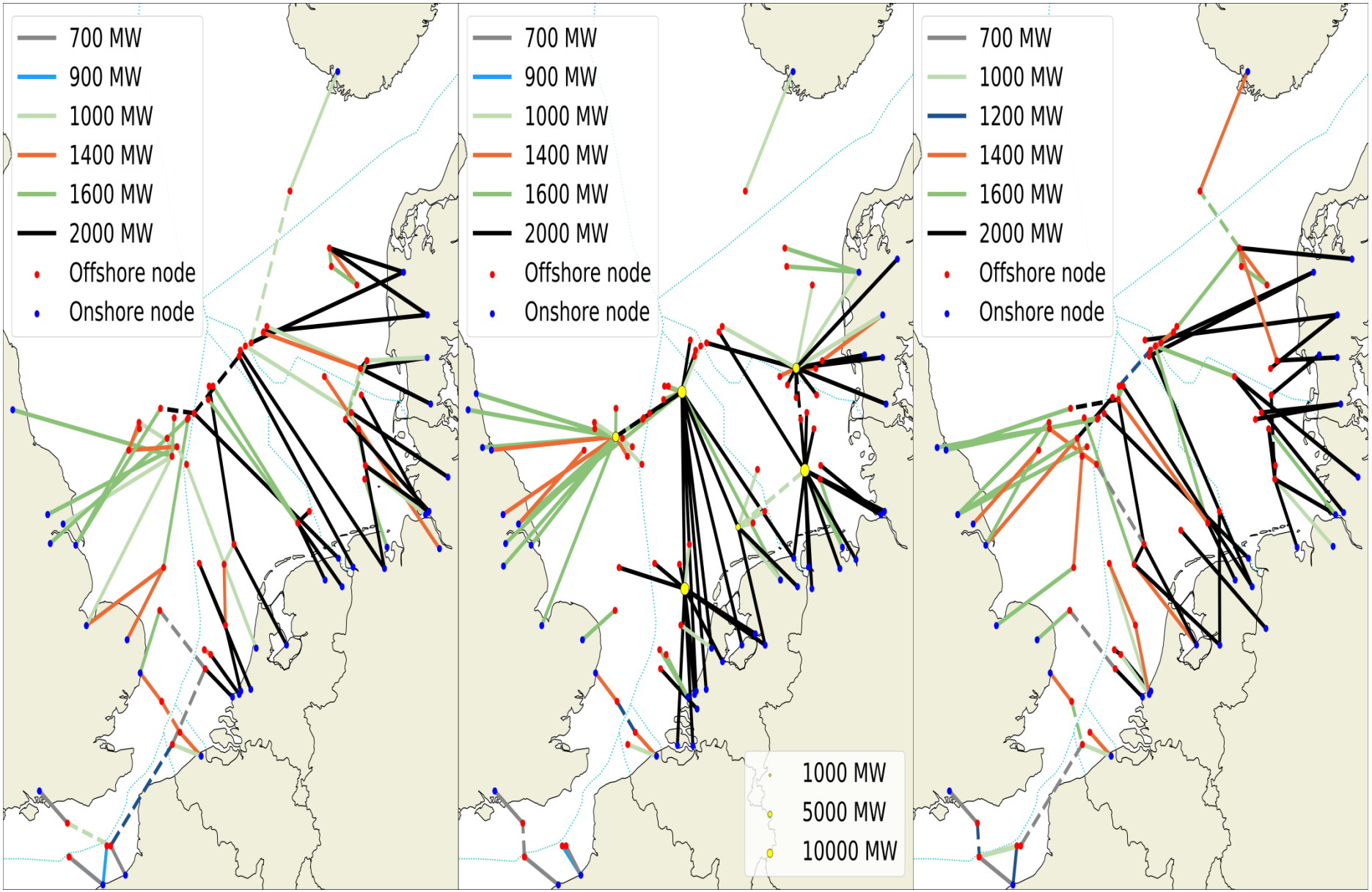


Figure 4-6 - From left to right: NAT, HUB and EUR concept representations of the North Seas by 2050

4.2 RECOMMENDATIONS ON TECHNOLOGY: TOPOLOGIES AND GRID IMPLEMENTATION

This section presents a set of recommendations that should be considered in order to successfully implement an HVDC grid. Each of them will be shortly characterised to provide a better understanding of the topic. First, some recommendations are made from the topology generation that can be distilled from the grid development described in the previous section. Then, several recommendations are made according to the research done by technical WPs. It includes recommendations on operation of the grid, control, stability and protection systems In-depth analyses are performed in Appendix III of this document and in Deliverable 1.7. Appendix III contains also assumptions that were taken while developing the Deployment Plan and are underlying the recommendations. All technologies considered within PROMOTioN and mentioned in the section below are described in Appendix II and the assumptions used within PROMOTioN on their rating, configuration and other characteristics are listed in Appendix III. For each of the following recommendations, their timing is also estimated and planned according to the topology generation.

4.2.1 STANDARDISE 2 GW OFFSHORE HVDC PLATFORMS

The topology generation shows a significant amount of 2GW OWFs radially connected in each of the topologies[5]. It is therefore recommended to develop a standard platform design (within procurement constraints) for these radial connections.

It is assumed cost reductions for 2GW point-to-point connections may be obtained by moving away from turn-key projects because of economies of scale and learning effects. It is therefore recommended to steer towards standardising a 2GW 525kV platform and converter design to be applied throughout the North Seas.

It is recommended to coordinate maritime spatial planning as this is key to reach 2GW by “aggregating” windfarms to be connected to a single offshore AC/DC converter. This allows the application of a standardised 2GW concept. This recommendation is further captured in section 4.3.2.1. The sensitivity analysis outlined that the point-to-point solution remains competitive if the maximum platform size and cable rating are similar. If this is not the case, the point-to-point solution becomes significantly more expensive.

2GW requires around 200-400km2 which appears realistic from the GIS study performed in Deliverable 12.2 and allows AC connections to an offshore HVDC platform. AC connections from the windfarm in 66 kV carry a cost reduction according to the CBA and it is therefore recommended to apply this into the 2GW concept. As 2 GW OWFs will be built from 2025 onward, standardising this concept will occur in that period. Standardisation will happen within the period, probably within 2 or 3 years, after which the standardised concept is ready to be applied by 2030.

4.2.2 INTRODUCE MESHING FOR INTERCONNECTION PURPOSES

In all concepts and scenarios, the topology will evolve gradually from a few multi-terminal connections to a more complex structure. Eventually, a backbone will interconnect several multi-terminal connections. It has also been shown that all wind scenarios require a high level of interconnection.

[5] Due to the amount of 2GW OWFs, these recommendations are steered towards a 2GW 525kV HVDC concept, but these recommendations are valid for other sizes as well in a lesser extent.

The combined use of the offshore grid for wind evacuation and interconnectors is an important driver for meshing/multi-terminal. It is therefore recommended to apply hybrid interconnection in cases where this is optimal i.e. when two OWFs are in close vicinity to each other.

Reduction in cable length from one concept to another is sensitive on input assumptions. Depending on the assumptions, the difference is very significant or not. If the difference is small, the costs of other aspects (such as protection devices, platforms, advanced controls) have to be considered. It is therefore recommended to apply meshing in areas where there is a large reduction of cable length if aspects like protection devices play a role.

The Dogger Bank seems an ideal candidate to form a backbone because of the short distances between OWFs. There are no clear benefits to connect all the multi-terminal structures together to form a single grid (meaning extra-costs and complexity). Therefore, it is recommended to apply meshing only when this leads to a decrease in cable length.

Increasing cable rating can theoretically reduce the most the total cable length but needs to consider more constraining N-1 system security aspects. It is therefore recommended to take into account technological developments in the future when planning the offshore grid.

In the topology generation, this kind of meshing is applied by 2030 in the NAT concept. Already, progress is made on such meshing on the DC side in current projects, but implementation is not yet ready. It is assumed that this will still take some time, around 2025.

4.2.3 ESTABLISH ARTIFICIAL ISLANDS IN PLACES WITH HIGH WIND ENERGY GENERATION DENSITY

The HUB concept shows that artificial islands in places where there is high wind energy generation density can significantly reduce costs. Although not further studied within PROMOTioN, there is a maximum distance at which connection to an artificial island is economically sensible. This distance is dynamic and is influenced by multiple factors, including the position of the OWF relative to the island and the onshore connection point, the combined evacuation of energy generated by multiple OWFs, the existence of flexibility on the island and the interconnection capacity on the island. It is recommended for artificial islands to be planned along with the establishment of multiple OWFs, as these factors are also influenced by the presence of other OWFs[6].

The artificial islands in the HUB concept are considered to be only replacements of offshore DC platforms, without the AC/DC converters being permanently linked. Whether or not the artificial islands could be connected on the DC side (e.g. with a ring-like DC busbar) has not been studied within PROMOTioN but could be an option for these islands. This would allow for more efficient transportation of wind energy, without converter losses, and the possibility to better control and direct power flow, but then could also require a protection system. It is therefore recommended to further study potential designs of the artificial islands, thereby including different interconnection options of the converters and the option of flexibilities on the island.

[6] For example, it is possible that connecting an OWF to an island is not attractive because of the absence of flexibilities on the island even though these flexibilities are economically sensible only when the capacity connected to the island is increased. If each separate OWF developer then decides not to connect to the island because of this reason, these flexibilities will never be established even though planning all these OWFs combined would be financially beneficial.

Although the topology generation shows the applicability of the islands already by 2025, this is realistically not feasible. The novelty of artificial islands gives them a long lead time of around 10 years. Progress on applying islands is already made today, which means that the concept is ready for implementation by 2030. Operation of these islands will take some time after this, allowing the island concept to become operational around 2032.

4.2.4 ENSURE INTEROPERABILITY OF COMPONENTS IN THE SYSTEM

While designing the offshore grid, a variety of components provided by different manufacturers may be needed. Thus, it is recommended to use components that will meet the offshore grid interoperability demand. This means that it is advised to apply the devices that can work with existing technologies without any interruption. Moreover, it is recommended to select components with the same communication interface in order to provide stable and easy control of the system. Furthermore, while selecting equipment manufacturers it is suggested to choose those that are able to adapt their equipment during their lifetime, if necessary due to interoperability issues. For this purpose, producers should commit to communicate some minimal set of relevant data (signals, measurement) for a common solving of issues. This guarantees that a grid extension may be possible with the same or updated components. This is likely to require changes to the typical contract structures and responsibilities between TSOs and suppliers.

No progress has been made officially on operability, although it is a topic in the PROMOTioN research. Due to the enormous complexity, it is assumed at least 10 years will be required for further research up to the moment that this can be implemented in official documents. It will then take some more time before it can be applied to the technologies, which is estimated at another 5 years.

4.2.5 ESTABLISH AN OFFSHORE HVDC GRID CODE

Multiple recommendations from technical Work Packages for e.g. grid planning and operation and control of an offshore grid may be combined in an offshore HVDC grid code. This should contain enough information to safely and effectively construct and operate a MOG, including information on the choice for bipoles, voltage level, reliability of the grid, dynamic voltage ranges, Fault Ride Through capability, control requirements and black start capability. The Grid Code needs to be sufficiently detailed to enable grid integration between different areas, but needs to be technology agnostic to allow for vendor innovations to be applicable in the grid. The concept of an Offshore HVDC Grid Code is relatively new, but has been proposed before. Drafting this Grid Code may still take several years, although the PROMOTioN technical Work Packages have already started to propose characteristics for the offshore grid. These are summarised in Appendix III. Working out the details and agreeing on the characteristics may still take quite some time, which is why it is assumed such a Grid Code will not be ready before 2030.

4.2.5.1 USE A BIPOLE CONFIGURATION FOR VOLTAGE SOURCE CONVERTERS

Several converter options and converter configurations are possible. For converters, it was considered to apply Diode Rectifier Units (DRUs) in the grid. This is a type of converter that converts AC to DC power and is significantly lighter and compact than more conventional (VSCs). However, DRUs technically only allow power flow in a single direction, while in meshed situations a bidirectional power flow is required. It was therefore not certain whether these converters were applicable to all concepts. This was, among others, a

reason to further discontinue the use of DRUs in the CBA in Deliverable 12.2, where a comparison was made using the same types of technologies in all concepts. It was therefore chosen to apply VSCs in all concepts, although theoretically DRUs could be used in radial configurations.

Due to the high transfer capacity of the converters and the cables to shore, it is recommended to apply a bipole configuration for the cables to shore. This influences the configuration of the converters as well. Bipole systems provide an inherrent redundancy allowing for continued but reduced transmission capability to be utilised by switching to monopole operation under single pole cable or converter fault conditions or maintenance outages. Although not strictly required for point-to-point configurations, this would be required for all structures of the grid that will or potentially could be part of a meshed structure

4.2.5.2 KEEP THE GRID RELIABLE

Planning criteria have to guarantee that the power system can match generation and load under normal conditions, thus when all transmission and generation objects are available. Therefore, firstly it is recommended to focus on reliability aspects of the MOG. Nonetheless, other elements like interoperability and transmission capacity also have to be considered in grid planning. These elements are concept-agnostic and are thus applied in all considered grid concepts. The following section therefore discusses the main grid planning recommendations, without a distinction being made between the concepts. More assumptions on the grid planning recommendations can be found in Appendix III.

To keep the grid reliable, it is advised to keep the global loss of power infeed on certain areas below the reference that is specified by these areas' grid codes in order to maintain the frequency of the onshore AC grid. Detailed values of the mentioned references are provided in in Appendix III of this document. Also concerned with reliability is the recommendation to clearly define responsibility regarding the ownership, construction, and maintenance of a MOG since the MOG will integrate both evacuations of offshore wind energy and evacuation trading within countries. This is discussed further in section 4.3.4 on the legal and governance framework necessary for a MOG.

Finally, during the grid planning process transmission capacity and voltage also have to be considered. Under normal conditions, it is recommended to keep voltages at all nodes between 0.95 and 1.05 p.u. Moreover, it is strictly advised to keep interconnector capacity at a value smaller than the maximum loss of active power injection of one of the connected areas.

4.2.5.3 ENSURE STABLE OPERATION AND CONTROL OF THE MESHED OFFSHORE GRID

While designing the onshore AC system of the Meshed Offshore Grid, active power control and frequency support requirements must be fulfilled. This means that the offshore grid has to operate within certain frequency ranges and has to be capable to withstand a certain rate of change of frequency. Detailed values of frequency ranges and active power support can be found in in Appendix III. Moreover, reactive power control and voltage support requirements have to be achieved as well. Therefore, detailed specification regarding voltage ranges and reactive power control are given also in in Appendix III. Additionally, the mentioned section present recommendations about control, fault ride-through capability, information exchange, protection devices, and settings requirements.

The offshore generation of meshed gird also has a range of constraints that has to be kept. Firstly, the objective of frequency stability and active power control are; turbine maximum power point tracking system,

frequency response, and active power control. Detailed requirements can be found in in Appendix III. Besides, a wind generator is required to withstand circuit faults; hence has to meet control and robust requirements during these faults. Furthermore, generator has to be able to fulfil stability, robustness and voltage requirements. Apart from this, during turning on the generator and designed offshore grid has to withstand start-up requirements. Detailed data for all of the mentioned needs are listed in in Appendix III.

Additionally, the Meshed Offshore Grid has to meet operation requirements that concern power, voltage response, robustness and operational ranges of HVDC terminal. This set of recommendations is presented in in Appendix III.

Finally, a properly designed offshore grid must realise DC control assumptions and requirements. One of these assumptions is that depending on planned outages and the expected wind production, changing the DC grid topology may be required. Therefore, it is recommended to consider the possibility to change the DC grid topology, either in a manual way or in an automatic way (i.e. optimal transmission switching). All of the remaining DC control recommendations are listed in Appendix III.

4.2.6 IMPLEMENT AN APPROPRIATE PROTECTION SYSTEM

Protection of a DC transmission system is much more challenging than an AC transmission systems. This is for two main reasons:

- DC current faults do not undergo regular zero-crossing[7], contrarily to AC faults. Their disturbance is therefore more challenging.
- DC faults cause high currents and must be broken much quicker than AC faults since DC devices have a narrow overload capability. It is suggested that they must be detected, located and cleared in a couple of milliseconds.

Several protection strategies have been under evaluation in PROMOTioN. A full-selective protection strategy includes protection on each single node within the system in which a fault could have a disruptive effect on the onshore grid. A partially selective protection system may isolate certain parts of the system and a non-selective strategy will isolate the entire system from the onshore grid. Although substantially cheaper protection strategies, the partially and non-selective protection strategies may require substantial compensation in the onshore grid through the sudden loss of significant power infeed into the onshore grid. More detailed specification and recommendations for each protection system strategy requirements can be found in Appendix III of this document. The protection strategy can be specifically chosen by each grid operator separately according PROMOTioN analysis. One of the conclusions is that disturbance far from a fault is less than anticipated. It is also found that it may be beneficial to be able to split the grid into different sections. There are no lock-in or interoperability issues expected from a difference in protection strategy by different grid operators. Therefore, this will remain a subject area for research throughout the entire period for each separate grid structure, from 2020 until 2050.

[7] A current flowing through metallic contacts will continue to flow through these contacts even when these are beginning to separate. This so-called 'arc' will extinguish naturally when current reaches 0, which happens with AC current due to its natural oscillation. Current of DC faults only reach zero-crossing after the entire high peak current that is generated because of the fault has passed through the arc, which is damaging to components.

APPLY DC CIRCUIT BREAKERS

It is recommended to install DCCBs only in coordinated grid solutions, or meshed topologies. Moreover, taking into account the fact that DCCBs are an expensive technology it is suggested to install them only on connections in which a fault can lead to a loss of power higher than the maximum loss of power infeed of the countries to which it is connected. DCCBs should first be demonstrated onshore in a real-life test setup as this is a less complex test environment than offshore. This can be done in for example the Hansa Power Bridge short term project, which will need some further analysis for a few years before it is ready for implementation around 2025. At the same time as delivering the onshore DCCB pilot project, preparations for the application of a DCCB in a real-life offshore setting can be made so that its application can be tested in an offshore situation. This could be done in the Ijmuiden Ver WindConnector concept, which is ready around 2027. This will again require some more years of research, which may be slightly longer due to the expected complexity of the project. Finally, DCCBs may be deployed offshore to protect the grid. This may be done after the testing of the offshore pilot DCCB has finished, after which a few years of testing and evaluating should allow the installation of the DCCBs. Where DCCBs may be installed and how many there will be depends on the chosen protection strategy, but analysis in PROMOTioN shows that indeed around 2035 this technology will be applied in real-life situations.

CONTINUE DEVELOPMENT IN GAS INSULATED SWITCHGEAR

It is highly recommended to continue to develop and apply GIS technology for DC assets, as it is a more compact solution than air insulated switchgear (AIS) which is a significant advantage in offshore solutions. Sulphur hexafluoride (SF_6), which has an extremely high global warming potential, is used as an insulating gas in current GIS installations. Therefore, it is recommended to develop other, less environmentally damaging insulating gases that can be used in GIS for both HVAC and HVDC applications. Similar to the DCCB pilot project, an HVDC GIS pilot project onshore would allow for testing of GIS technology in a real-life setting so it is ready for deployment by 2030. A successful onshore pilot project would provide a strong argument for the deployment of the technology in an offshore environment. GIS technology, albeit with SF_6 gas, should be ready for deployment today for testing.

4.2.7 ALLOW THE APPLICATION OF ANTICIPATORY INVESTMENTS IN THE GRID

In combination with the offshore DCCB pilot project, the PROMOTioN short-term project on the Ijmuiden Ver WindConnector proposes the application of a platform that is ready for expansion for the possible application of a DCCB and/or an additional DC cable. Due to long planning lead-time this decision has to be made early to ensure the deployment of a very first expansion-ready platform. This requires an anticipatory investment, which is required when meshing an offshore grid. Due to the lead-time, it is proposed to start with exploring options for this from 2020 onward as it would take multiple years to further explore. If then the implementation is ready by 2025, the anticipatory investment can be done by around 2027.

4.2.8 EXPLORE THE NEED FOR FLEXIBILITY IN THE SYSTEM

Increasing onshore hosting capacity reduces significantly the total cable length required for all concepts but is more beneficial for the NAT, EUR and HUB concepts. Additionally, in the benefit analysis in the high wind scenario, it was shown that an increase in coordination offshore leads to a counterintuitive increase of offshore wind energy curtailment. This is because in these topologies not all wind energy that would be

transported to land would then be able to be transported to the areas where it is required. For these reasons is recommended to take into account the capacity of the onshore grid in planning the offshore grid. Especially in the concepts where a large amount of cooperation is required to establish the offshore grid, this same cooperation is required onshore. This is required to facilitate either an increase of interconnection capacities onshore or large-scale storage onshore and/or offshore. Although not within the scope of PROMOTioN, the applicability of flexibilities is considered important and will have to be considered throughout the entire period up to 2050.

4.2.9 RESEARCH THE NEED FOR DC/DC CONVERTERS IN THE SYSTEM

As complexity of the grid increases it may be an opportunity to explore the benefits of connecting smaller meshed grids to create a highly complex meshed grid. However, PROMOTioN analysis found that these grids will be very difficult to properly control. A potential application of DC/DC converters will therefore then have to be explored, which can be used to control the DC power flow. Without this control, the natural flow of DC power could be different than expected which could lead to potentially dangerous situations. Due to the current TRL of DC/DC converters, research into this technology will have to begin from 2020 onward, all the way up to 2050.

4.3 RECOMMENDATIONS ON ESTABLISHING A LEGAL, REGULATORY AND FINANCIAL FRAMEWORK

Across the North Seas countries, there are different legal and regulatory regimes for transmission networks connecting offshore generation to shore. These have been established primarily to enable radial connections to shore from OWFs within a country's EEZ. Similarly, the EU rules on interconnector regulation allow for flexibility in the way interconnectors are remunerated. This permits differences in the regulatory regime for individual interconnectors, which are agreed bilaterally between the two North Seas countries being connected. To date, these legal and regulatory frameworks have provided sufficient clarity and stability to transmission asset owners and operators on their responsibilities and how they will be remunerated for discharging these, to enable transmission asset developers to raise finance for investment in new assets.

The development of multi-terminal connections introduces a new 'offshore hybrid asset' – a transmission asset between two countries to which one or more OWFs are also connected. The configuration of multiple hybrid assets under the different grid concepts set out earlier in this report is likely to result in links between several countries, with wind energy generated in the EEZ of one country potentially being utilised in a second country, following a transmission pathway which may span multiple transmission assets. This presents new questions for owners and operators of both OWFs and transmission assets, including:

1. **Legal Framework**:
   - What legal instruments are required to develop an appropriate legal framework for the MOG?
   - How are assets classified, and what are the implications when asset classification changes?
2. **Planning**: Who makes decisions of where and when new transmission assets and wind farms are built; and what methodology is used?
3. **Investment Framework**: What financial structures need to be put in place to enable transmission asset owners to raise sufficient finance for new investment in the transmission system?
4. **Regulation of the transmission network**:

- Who regulates the offshore transmission assets?
- What is the ownership structure of the MOG?
- How is system operation coordinated across the network?

5. **Revenue Mechanisms:**
    - How is the revenue of OWF owners determined?
    - How is the revenue of transmission asset owners determined?
    - How are national support schemes for OWFs reconciled with the fact that offshore wind in one EEZ may be exported directly to another?
    - How does the regulator determine the price paid by network users for access to the transmission network?
    - How does the regulator determine the revenue received by the transmission owner?
6. **Operational**:
    - How is supply and demand balanced across a MOG and the countries it is connected to?
    - What technical codes need to be aligned across a MOG?
7. **Decommissioning**: How should assets be decommissioned and should (international) guidance be developed and applied?

WP7 has examined options for the legal, economic and financial framework for a MOG. This section of the report summarises their findings and recommendations in response to the questions above. Further detail on the recommendations can be found in the detailed WP7 reports: Deliverable 7.2 (legal), Deliverable 7.4 (economic), Deliverable 7.6 (financial) and Deliverable 7.9 (final policy recommendations).

4.3.1 LEGAL FRAMEWORK FOR MOG TRANSMISSION ASSETS

Deliverable 7.2 presents recommendations on changes required to current legislation in order to accommodate a MOG. A description of current legal instruments, their scope and applicability to offshore assets in the EU is provided in this deliverable. A brief summary of principles which inform the legal framework is provided here, followed by key recommendations for establishing a legal framework and, in particular, asset definition.

4.3.1.1 SUBSIDIARITY AND PROPORTIONALITY: PRINCIPLES FOR IDENTIFIYING AN APPROPRIATE FRAMEWORK

There is no 'one size fits all' legal framework. Therefore, for each aspect of the legal framework that needs to change to accommodate a MOG, the appropriate mechanism must be identified using two principles – subsidiarity and proportionality.

SUBSIDIARITY

Is it possible to adequately address an issue on national level?

If yes, an issue should be dealt with at national, rather than EU or international level. If no, the choice between EU and international law can be determined by asking:

1. Is it important to have one solution for all states?
2. Is the issue only relevant to North Sea coastal states (not to other EU Member States)?
3. Did the EU already make use of its competence to legislate on the issue?
4. Is enforceability of the agreement/rules important?

If the first two questions are answered affirmatively, this points towards a solution under international law. If the third and fourth questions are answered affirmatively, this points towards a solution under EU law.

PROPORTIONALITY

Solutions should be found using the least invasive instrument possible. The appropriate level can be found by asking:

- Is it important that the agreement is enforceable?
- Is it (too) difficult to reach a binding agreement?

If enforceability is important, this suggests a hard (binding) law is required. If it is too difficult to reach a binding agreement, a soft law instrument (such as international guidelines) may be a valuable alternative.

These two principles are summarised in the Figure 4-7 below and have been considered in all recommendations made in Deliverable 7.2.

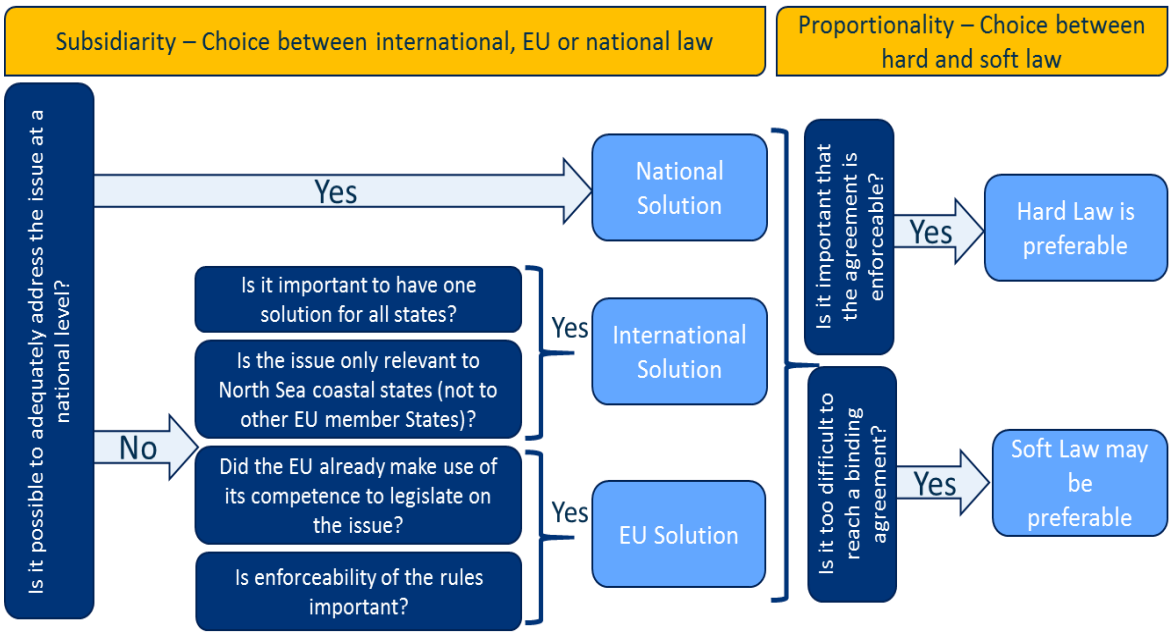


Figure 4-7 - Decision tree for identifying the most suitable legal instrument (from Deliverable 7.9)

4.3.1.2 ESTABLISHING A LEGAL FRAMEWORK

The North Sea coastal states have to cooperate if a MOG is to be built in the North Sea. States currently coordinate their plans bilaterally and most coastal states cooperate with each other in the context of the EU. In order to provide a framework for the cooperation of the North Sea states, it is necessary to adopt an international agreement to which the states participating in the MOG, as well as the EU (as the competent authority for many energy market related topics) are signatories.

Recommendation: This agreement (a 'mixed partial agreement') should set out the objectives and high-level principles of the MOG, including a structure for governance, decision making and cooperation, for example an annual high-level conference and additional technical committees. Moreover, the agreement should indicate the way disputes between the connected states about the MOG are handled. This agreement provides legal certainty for the states, the grid owners and the parties connected to the grid.

These additional aspects of the proposed mixed partial agreement are discussed later in this chapter.

4.3.1.3 DEFINING OFFSHORE HYBRID ASSETS

A key recommendation of the interim findings from WP7 (Deliverable 7.1) was that a legal definition of an 'offshore hybrid asset' was necessary at both an EU and international level in order to distinguish MOG assets from radially connected wind farms and interconnectors between countries.

A hybrid asset combines the connection of OWFs with interconnection between multiple countries. They are the building blocks of the MOG and can reduce the number of offshore cables required to connect a given level of generation capacity.

Hybrid assets can be created through:

- Existing OWFs (or hubs) in different countries that are already connected to their 'own' countries which are later connected to each other
- Offshore wind farms connected to an existing interconnector (Tee-in)
- The entire asset (windfarm connection and interconnection) is constructed more or less at the same time
- A MOG with grid extensions from time to time

DEFINING 'OFFSHORE HYBRID ASSET' AT AN EU LEVEL

A definition of an offshore hybrid asset is necessary because there are legal uncertainties in the EU law about whether cables of an offshore grid fall under the category 'interconnectors', national electricity network evacuation cables or whether they are a new category which does not yet exist. In addition, the regime under which the hybrid assets fall is unclear. Asset classification in the EU law (regulatory level) is more specific than international law (jurisdictional level), and the categorization of the cable influences how the assets are regulated in terms of conditions for access, income (tariffs) and ownership.

The lack of a definition for hybrid assets increases the risk that infrastructure is not used efficiently, and either additional cables would be laid to circumvent the legal uncertainty increasing financial and environmental cost, or investors would be unwilling to invest in a MOG whilst legal uncertainty remained.

Following recommendations in Deliverable 7.1 and stakeholder engagement, the following definition of offshore hybrid asset' was adopted in the Electricity Regulation (EC 2016/0379(COD), adopted by EU parliament 26 March 2019).

> *Recital 66: Investments in major new infrastructure should be promoted strongly while ensuring the proper functioning of the internal market in electricity. In order to enhance the positive effect of exempted direct current interconnectors on competition and security of supply, market interest during the project-planning phase should be tested and congestion management rules should be adopted. (…) Exemptions granted under Regulation (EC) No 1228/2003 continue to apply until the scheduled expiry date as decided in the granted exemption decision.* ***Offshore electricity infrastructure with dual functionality (so-called 'offshore hybrid assets') combining transport of offshore wind energy to shore and interconnectors, should also be eligible for exemption such as under the rules applicable to new direct current interconnectors. Where necessary, the regulatory framework should duly consider the specific situation of these assets to overcome barriers to the realisation of societally cost-efficient offshore hybrid assets.***

It is a great step forward that a definition of 'offshore hybrid asset' has been included in the recitals to the Electricity Regulation. This definition would work well for three of the four ways in which hybrid assets could be constructed (listed above). The second option (tee-in) would not work under this definition as it would first be classed as an interconnector, before becoming a hybrid asset. However, long term grid planning should reduce the likelihood of a tee-in construction being required.

However, the offshore hybrid asset definition does not yet provide the legal certainty needed for the construction of an offshore grid, as it only creates an exemption possibility (new DC interconnectors) and the possibility to provide case-by-case regulation for hybrid assets.

Recommendation (short term): Deliverable 7.2 recommends that the 'offshore hybrid asset' should be adopted in the **operative** part of the legislation rather than in the recital, and that the legislation should specify the legal and regulatory framework for offshore hybrid assets in more detail. This is because, through the wording and the position in the Regulation, the current recital does not yet give sufficient legal certainty: "where necessary" and "should duly consider" leave a large margin of interpretation, and the 'offshore hybrid asset' is not mentioned in the definitions or the operative part of the Regulation.

DEFINING 'OFFSHORE HYBRID ASSET' AT AN INTERNATIONAL LEVEL

As the MOG will connect countries both inside and outside the EU, an international agreement on the definition of an 'offshore hybrid asset' would provide greater legal certainty to all MOG connected countries. At present, it is unclear under international definitions (under the United National Convention on the Law of the Seas, UNCLOS) whether a hybrid asset falls under the definition of:

- cables and pipelines (interconnectors), leading to limited jurisdiction for coastal states; or
- installations and structures used for the economic exploration and exploitation of the sea (namely OWFs and the cables needed to connect OWFs to shore), leading to functional jurisdiction for coastal states.

Recommendation (Long term): Deliverable 7.2 recommends that a common agreed definition of 'offshore hybrid asset´ could be included in the mixed partial agreement described in Section 4.3.1.2.; This would not require any changes to UNCLOS, but simply set out the common interpretation of these laws in relation to offshore hybrid assets. This is likely to take longer to achieve than a change to the EU Electricity Regulation and thus so is identified to be a longer-term aim.

4.3.2 PLANNING FOR A MESHED OFFSHORE GRID

Currently the location of OWFs and their connection to shore is a matter for individual North Seas countries, whilst the business case for new interconnector investments is based on a cost-benefit analysis led by the connecting countries. Long-term plans for new transmission assets across the North Seas are captured in the Ten Year Network Development Plan (TYNDP). This does include some meshed projects, notably the first North Seas Wind Power Hub which aims to connect 12 GW of offshore wind power to Germany, Netherlands and Denmark[8]. However, it does not provide a roadmap for a meshed offshore network based on the grid concepts considered in the PROMOTioN project.

[8] https://tyndp.entsoe.eu/tyndp2018/projects/projects/335

The Economic Framework (Deliverable 7.4) identified three key aspects of current planning regimes where changes could help to deliver a meshed offshore network in a more timely and cost-effective way. The three aspects include:

- Onshore-offshore coordination (where should OWFs be located and how should they be connected to shore). This also helps to identify anticipatory investment need. Funding anticipatory investment is addressed in Section 4.4.
- CBA methods,
- Public participation in the planning process

In addition, the Legal Framework (Deliverable 7.2) examined the impact of different planning, permitting and decommissioning rules for offshore transmission assets across the North Seas.

Each of these elements is now presented in turn. For each element, the barriers presented by current offshore regulatory regimes are presented. This is followed by a summary of the options considered in work package 7 and their recommendations.

4.3.2.1 ONSHORE-OFFSHORE COORDINATION

Barrier: Across North Seas countries there are different approaches to identifying the location of new OWFs as well as differences in who is responsible for building connections from the OWF to the onshore grid and how OWF developers are charged for new connections.

Importance for the MOG: Different approaches to locating OWFs can make it difficult to develop long –term plans for network development, which makes the case for anticipatory investment in centralised hubs in the North Sea more difficult. Differences in connection charges could create a market distortion, resulting in OWF locations determined by differences in connection charges between countries, rather than the best wind resources.

In addition to the analysis in Deliverable 7.4, the interviews and literature review undertaken as part of the Financial Framework (Deliverable 7.6) concluded that the current lack of coordination on infrastructure development is one factor holding investors back from investing in a MOG in the North Sea.

Analysis and Recommendations: The analysis covered three elements of onshore-offshore coordination: (1) Siting new wind farms; (2) Grid access responsibility and; (3) Grid connection costs

SITING NEW WIND FARMS

Options: Across North Seas countries, there are three approaches to identifying new OWF locations:

- **Open-door**: The most flexible approach for developers. In this approach, the offshore wind developer selects a site for the wind project. Their proposal must be considered and approved by the relevant authorities and stakeholders. For example: the developer will need to arrange a connection agreement with the onshore network owner to which the wind farm will connect.
- **Zoned approach**: In this approach, the relevant authority identifies a zone for offshore wind development. The development rights for the construction of a wind farm(s) within the zone are then offered to prospective developers. The developers have flexibility over the final location of the wind farm within the zone (subject to receiving the necessary planning permissions).

- **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.

Recommendation:

*Zoned or single-site approach provides earlier clarity on long-term plans***:** Whilst it is not necessary for all North Seas countries to align on their approach to siting wind farms, having a long-term view of prospective sites can provide greater clarity on the optimal configuration of the offshore transmission network and identify any appropriate anticipatory investment needs. This points towards the zoned or single-site approach. The TYNDP process already coordinates and presents proposed transmission investment scenarios out to 2040; potential wind farm developments should be identified as far in advance as possible in order to feed into long term scenarios for network development. In alignment with these recommendations from the Economic Framework (Deliverable 7.4), establishing robust, long-term plans for network development, which are binding on the countries involved, would provide clarity to investors on the pipeline of projects (Deliverable 7.6). A multi-national approach to grid and wind farm planning could be set out in an international agreement, such as a mixed partial agreement (Deliverable 7.2, and described in more detail in Section 2.7.3).

GRID ACCESS RESPONSIBILITY

Options: The party responsible for connecting OWFs to the onshore grid differs across North Sea countries. Whilst all OWFs will need to work with the onshore transmission network owner to agree upon a suitable connection point, the responsibility for building the transmission connection to shore can differ:

- **TSO-led model**: In this approach, the onshore transmission system owner or operator (TSO) is responsible for connecting the OWF to the onshore grid. Generally, the TSO risks financial penalties for late delivery.
- **Developer-led model**: In this approach, the OWF developer is responsible for building the connection between the wind farm and the onshore grid. The onshore TSO is responsible for any onshore reinforcement works at the point of onshore connection. Similar to the TSO-led model, the TSO often risks financial penalties for late delivery of the appropriate onshore connection. This has been implemented in the UK through its 'Generator Build' model under the Offshore Transmission Owner (OFTO) model. Once construction is completed the asset is transferred to a third party OFTO to maintain the asset over its lifetime. The OFTO is appointed following a competitive tender process run by the NRA, Ofgem.
- **Third party-led model**: In this approach, a third-party grid developer is mandated to connect the wind farm to the onshore grid in a specified time frame. The onshore TSO is responsible for any onshore reinforcement works at the point of onshore connection. Both the third-party developer and onshore TSO could risk financial penalties for late delivery. The only country where this approach is an option is the UK. This approach, called OFTO-Build, is an alternative to the 'Generator Build' model described above. The generator can choose which approach to take. To date, the 'OFTO-Build' model has not been used.

Recommendation:

Appropriate approach depends on ownership and location of MOG assets: There is no single appropriate approach for MOG assets; this will depend on the ownership model for MOG assets and the order in which

assets are built – it may be more appropriate for a TSO or similar third party to deliver transmission assets which will be used by several OWFs and interconnector, whilst a developer may be best placed to build assets for the sole use of their wind farm.

GRID CONNECTION COSTS

Options: Across North Seas countries, there are costs associated with a connection agreement between a generator and the onshore transmission network. The cost of a connection agreement is typically classified in one of three ways: 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.

- **Super shallow**: 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.
- **Shallow**: 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.
- **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.

Recommendation:
A consistent approach will remove market distortions affecting the location of OWFs. A super-shallow approach may be the easiest approach to regulate: The case studies in Deliverable 7.4 show that most countries across the North Seas adopt a shallow or super-shallow approach to offshore connections, with several countries considering adopting a super shallow approach. Given the potential physical complexity of a MOG, with OWFs connecting to multiple countries, potentially via existing interconnectors or island hubs, a super-shallow approach may be the easiest to regulate. Trying to calculate deep connection costs is likely to be overly complex, and may be very difficult if OWFs are part of small bidding zone (as recommended in Section 4.5), rather than associated with an onshore national bidding zone. Applying a consistent approach to MOG assets will also remove any market distortions which may impact the location of OWFs.

This will ultimately be a decision for the regulator of the MOG, in conjunction with the onshore TSOs of the North Seas countries. It should be noted that a consistent approach to connection costs across a MOG may result in differences between different types of connection with a given country (e.g. the connection costs of a single, radially connected wind farm may be different to that of a wind farm in the same EEZ but connected to the MOG).

4.3.2.2 COST-BENEFIT ANALYSIS METHODS

Barrier (1): Proposed interconnector projects (or other Projects of Common Interest) often use different CBA methodologies. Projects are also often considered in isolation, not taking into account the impact of future transmission assets, which may result in the benefits of an investment being over-stated.

Importance for the MOG: Building a MOG in the North Seas is a complex undertaking. The case for doing so must be based on robust analysis, taking into account the potential impact of long-term future energy scenarios on the viability of near-term investments. Multiple MOG grid configurations are possible; a consistent methodology is crucial for comparison.

Analysis and Recommendations: Deliverable 7.4 presents a detailed review of the current ENTSO-E CBA methodology and the extent to which this has been applied to recent projects. This highlights that the current approach taken is often insufficient in fully recognising the impact of subsequent investments on the investment under consideration. To deal with the interactions between transmission investments, Deliverable 7.4 firstly recommends introducing clearer criteria on when projects should be considered as part of a cluster for CBA. These criteria need to be established to avoid over-clustering which could lead to the development of inefficient projects. Two criteria are necessary to decide on whether to add a project to a cluster:

- the level of additional benefit delivered to the cluster by including another project; and
- the 'time criterion'; how far apart in time the development of the clustered projects are.

The threshold for these criteria needs to be decided and implemented by ENTSO-E following further stakeholder engagement.

The second recommendation in Deliverable 7.4 is to compare a project against two baselines in order to identify potential synergies between new projects. These two baselines should be:

- 'Business-as-usual' grid plus all projects which are part of the CBA. The impact of taking-one-out-at-a-time (TOOT) should be assessed.
- The business-as-usual grid only. The impact of putting-one-in-at-a-time (PINT) for each of the projects should be assessed.

Neither approach will give the true value of a single project (generally, the value estimation by applying TOOT is overly conservative, while the PINT approach is too optimistic). However, a significant difference in the value of the PCI project when compared against each baselines indicates a significant interaction with other projects, for which supplementary analysis would be recommended. Implementing these improvements could be the responsibility of the European Network of Transmission System Operators for Electricity (ENTSO-E) or regional groups instead of individual project promoters who may lack the information and resources to do this.

Barrier (2): There is a lack of transparency about costs in decision making process for Projects of Common Interest (PCIs).

Importance for the MOG: As with any CBA for transmission investment, clarity and consistency across project inputs is necessary to allow comparisons between projects and to improve trust in the decision-making process.

Recommendations: The ENTSO-E CBA methodology should take steps to move towards an open source CBA model. It should be noted that this recommendation stands regardless of MOG development and should be applied to the assessment of all PCIs. Similarly, the development of an open source CBA model is not a pre-requisite for the development of a MOG but would allow for a more clarity and consistency across the CBAs undertaken as part of its development.

Barrier (3): There is perception amongst some stakeholders that decisions on whether or not to invest in PCIs are not made based on objective criteria.

Importance for the MOG: Similar to the previous barrier, clarity and consistency on the decision making process will improve trust in the decision making process. Countries will have individual preferences and requirements on how the MOG develops but these should be transparent.

Recommendation: Establishing the priorities of different countries or Regional Groups at the start of the process to determine which projects are taken forward as PCIs, would increase the transparency of the decision making process. This could be expressed via the eligibility criteria.

Projects which did not meet these criteria could be removed at this early stage prior to conducting a CBA which fully monetised the value of project. Full monetization of the value of PCIs through the CBA would make it easier to directly compare projects.

As above, it should be noted that this recommendation stands regardless of MOG development and should be applied to the assessment of all PCIs. Equally, adopting this recommendation is not a pre-requisite of MOG development but could improve the assessment of proposed MOG investments.

4.3.2.3 PLANNING AND PERMITTING PROCESSES

Barrier: Planning and permitting procedures are perceived as a key risk in large infrastructure projects. Permitting issues become increasingly burdensome when the projects concerned span more than one jurisdiction, with the possibility of these risks materializing in two (or more) countries. Permitting can cause offshore infrastructure projects to be delayed by several years.

Importance for the MOG: A streamlined permitting processes will be necessary to deliver and connect the offshore wind projected in the PROMOTioN scenarios. Lowering the perceived risks associated with planning and permitting of transmission assets and OWFs will also lower the costs of financing the MOG.

Recommendations:

Streamline the permitting process to reduce the risk of legislative change during project development: This risk increases if the planning process is long. Enabling the necessary permits to be granted within one year of application would reduce this risk. In addition, if permits for OWFs are delayed, this may lead to suboptimal use of existing transmission assets, particularly in a hub-based connection. It is recommended that regulatory authorities involved in the planning process adhere to the principle that, once granted, permits/licenses will remain valid for the duration of the construction and operation phase.

Decouple the OWF permitting process from cable permitting process but coordinate the projected commissioning dates: This is recommended for nations where the permitting process for one aspect of a wind farm may take longer and/or where the location and size of wind farms are known before developers have been allocated to them. This principle will also become increasingly relevant in meshed grids, where the development of transmission assets will become increasingly decoupled from the construction of a single wind farm.

Simplify the permitting process by creating a one-stop-shop for key project permits: Different countries have different permitting processes, involving several different authorities and permits (some of which are interdependent). Constructing assets across two or more jurisdictions increases the complexity for the developer and the risk that the timing of permits is misaligned. A one-stop-shop for key project permits could

reduce the number of permits required, shorten the process for acquiring the permits and reduce the number of authorities involved within a single country. This reduces complexity and increases efficiency and can enable planning experts to focus on specific types of projects. Planning and permitting certainty also remains a key issue in the risk assessment by potential grid developers and impacts project risk and thus cost.

For cross-border projects granted PCI status, this one-stop shop approach should also apply. However, experience indicates that this process can still be burdensome and the 'one-stop' principle is not always applied. Improved implementation of this principle could streamline permitting for MOG assets. Alternatively, legislators could join the permitting process between neighbouring countries for cross-border projects. This is only likely to be effective in cases when there is already a high degree of cooperation and harmonization between the participating countries, otherwise there is a risk of legislative change causing further delays.

Move towards joint Environmental Impact Assessments (EIAs) for cross border projects, initially through a pilot project: The construction, operation and decommissioning of an offshore grid has an impact on the environment. Even though EU law does not require an EIA for submarine cables, they are required for offshore constructions such as convertor stations, and many countries require an EIA for the whole transmission project through their national legislation. The criteria for EIAs and for mitigation measures differ per country and EIAs have to be made on a national level.[9] This means that cross-border projects may require two or more EIAs; each of which could result in different mitigation actions for the project developer. This adds time and cost to the permitting process.

Moving towards a joint EIA process would reduce time and cost and ensure consistency of approach across the project. Moreover, it becomes increasingly important to take into account the cumulative environmental impact of projects. With a joint EIA process, this may also be facilitated. A pilot project involving cooperation between the legislator and executive authorities involved in the permitting process from the participating countries, and the project developer could test the effectiveness of this approach.

Develop a clear definition of hybrid assets (discussed in more detail in Section 4.3.1.3): For the MOG, the most pressing issue is to embed the definition of hybrid assets into legislation, develop a regulatory regime and agree how hybrid assets should be treated under planning and permitting regulations. More generally, technology is always likely to develop more quickly than legislation. The risk of legislation becoming outdated by developments in technology (e.g. energy storage offshore) can be mitigated by including high level principles in primary legislation and devolving the details to secondary legislation which can be amended more easily.

4.3.2.4 PUBLIC PARTICIPATION IN THE PLANNING PROCESS

Barrier*:* Stakeholder objections to new OWF or transmission asset development could delay or prevent the deployment of the MOG and be off-putting to potential investors. Litigation (appeals procedures) can take a long time and cause uncertainty over whether a granted permit is valid.

[9] For example, J. Phylip-Jones, T. Fischer, 'EIA for Wind Farms in the United Kingdom and Germany', *Journal of Environmental Assessment Policy and Management*, Vol. 15, no. 2 (April 2013) provides a comparison of the contents and the quality of EIAs for German and UK offshore and onshore windfarms.

Importance for the MOG: Whilst current planning processes have enabled significant deployment of offshore wind to date, delays in the planning process could dampen the rate of deployment, reducing the likelihood of meeting national and European targets for greenhouse gas emissions reduction.

Recommendations: Effective stakeholder engagement is a key part of the planning and permitting process. There is no single 'correct' approach to stakeholder engagement, but case studies on public acceptance of new developments highlight the positive impact of both greater engagement by the project developer with the public early on in the planning process, and community ownership models (Deliverable 7.4). Whilst not a pre-requisite of a MOG, adopting best practice techniques in stakeholder engagement can have an impact on the rate of offshore wind deployment.

Deliverable 7.2 notes that an official appeal procedure should be available under national law.[10]

4.3.3 FINANCIAL FRAMEWORK - INVESTING IN A MESHED OFFSHORE GRID

An overarching finding from Deliverable 7.6 (Financial Framework) is that a clear legal and regulatory governance structure is a prerequisite for investors. Clarity is needed on the ownership structure of the transmission assets, and the responsibilities and remuneration mechanisms for transmission owners. Investors need to have confidence that the regulatory regime is stable and clarity on if/how it will adjust should the purpose of the transmission asset change.

Assuming this regulatory framework is in place, attracting sufficient funding will require clarity on the risk and return profile of investment in offshore transmission assets and mechanisms to allow whoever owns offshore transmission assets to attract different types of funding in order to reach to necessary level of investment. Recommendations from Deliverable 7.6 have been highlighted throughout this chapter. This section presents remaining recommendations related to the revenue transmission owners should receive and the types of funding they should seek to access.

4.3.3.1 FUNDING ANTICIPATORY INVESTMENTS

Barrier: Transmission Owners will only invest in assets which they know they will receive revenue for. Investors typically do not receive revenue for assets which are oversized or not used. This prevents anticipatory investment.

Importance for the MOG: A Meshed Offshore Grid will almost certainly require some form of anticipatory investment (e.g. in oversized convertor platforms or islands). The approach to remunerating anticipatory investment differs across North Seas countries. A coordinated approach to assess the need for, and remuneration of, anticipatory investment, is needed to provide clarity to investors.

Recommendation (short term): Use EU financial support (Connecting Europe Facility (CEF)/ EEPR funding) to fund anticipatory investment, thereby reducing the risk of stranded assets for investors and bridging the financing gap due to (currently) inadequate cost allocation mechanisms and unlock the

[10] This follows from general principles of administrative law that exist in many jurisdictions: individuals should be able to make sure that decisions directed to them are prepared well and considered properly.

necessary cross-border anticipatory grid investments that the national governments alone cannot deliver (see also Section 4.3.5.4 on CBCA).

Recommendation (Long term): anticipatory cross-border investments should be included in the TSOs' regulated asset base (if this is how the regulator chooses to remunerate transmission owners) and included in the regulatory remuneration calculation.

4.3.3.2 REVENUE DURING CONSTRUCTION

Barrier: The construction phase entails the highest risk of a transmission project due to technical risks and potential delays arising from permitting and public processes. The interest rate of financing during construction is higher than during the operational phase to account for these risks. This factors could be prohibitive for larger construction projects.

Importance for the MOG: Individual construction projects within the MOG could be substantial and have a long construction period.

Recommendation: Those constructing transmission assets should receive some revenue during the construction and commissioning period. It is argued that this support will enable construction of larger, longer-term projects, and reduce the substantial interest payments accrued during construction. This would be similar to Germany and the Netherlands regulatory TSO regime. A Cap and Floor regime could limit consumer exposure to spiralling costs.

4.3.3.3 ESTABLISH LIABILITY REGIME

Barrier: Lack of clarity on liabilities for late delivery or poor maintenance of MOG transmission assets could prevent investors from financing both the MOG and OWFs.

Importance for the MOG: As mentioned above, clarity on how risks are apportioned across actors in the offshore transmission network is necessary to enable investors to assess the attractiveness of investing in offshore assets. One part of this is to establish clear guidance on the liabilities offshore transmission owners will face if they (i) fail to construct assets on time and/or (ii) fail to maintain the assets such that they operate reliably.

Recommendation: A liability regime should be established as part of the regulatory framework for offshore transmission assets. This regime should clearly define and allocate liabilities regarding the operation and maintenance of the assets and the OWF compensation due to delays in commissioning or non-availability of the grid (Deliverable 7.6, section 3.5, 6.2).

4.3.3.4 ENABLING ALTERNATIVE FUNDING STRUCTURES AND FINANCIAL INSTRUMENTS

Barrier: In some North Seas countries, TSO legal ownership restrictions hinder equity provision and the amount of debt they can leverage. In addition, TSOs are unlikely to be willing to risk their current credit rating by funding investment projects from their balance sheet.

Importance for MOG: Delivering the level of investment required for a MOG, particularly under a high wind deployment scenario, will require both debt and equity funding. It will not be practicable to finance investment off-balance sheet or through public funds alone.

Recommendation: Alternative financing structures and financial instruments should be introduced to enable new sources of finance to invest in transmission assets. Alternative structures, such as Special Purpose Vehicles (SPVs) for individual transmission projects, could allow additional finance to be raised whilst reducing the risk to the parent company. The OFTO regime in the UK is one example of how transmission networks can be opened up to new investors. Also, in Germany, TenneT incorporate SPVs by forming equity partnerships for individual connection projects. The majority of voting rights are retained by TenneT leaving a certain part of the economic interest with external investors. Financial instruments, such as (hybrid) green bonds with low interest rates and long maturities could be a successful form of corporate fundraising for offshore transmission assets with an environmental added value.

4.3.3.5 ENABLING INNOVATION IN DEVELOPMENT

Barrier: Some North Seas countries include funding for innovation in the price controls of their TSOs however this is not common across all countries. In addition, legislation relating to transmission networks can be a barrier to deploying innovation on the grid.

Importance for MOG: The deployment of meshed HVDC assets in the North Sea is not ‘business as usual’. Technical developments will be made as the grid develops and the regulation of the grid should be flexible enough to incorporate this (Deliverable 7.2) and there should be funding available to support innovation (Deliverable 7.6)

Recommendation (financial): Make EU financial support (CEF/ EEPR funding) available to demonstrate innovative technology as this will reduce the risk profile for other investors in the demonstration project and can accelerate the technical progress of the industry.

Recommendation (legal): Ensure the governance framework is flexible enough to allow use of new technologies that come to the market. Use long-term planning as a way of anticipating investment needs and periodically review network codes to ensure they are fit for purpose and put in place an efficient change process

4.3.4 REGULATION OF THE TRANSMISSION NETWORK

Deciding who regulates the MOG is a key prerequisite of the regulatory framework. From this decisions can be made on how the grid is owned and operated. WP7 has explored the current legal, regulatory and financial frameworks applicable across the North Seas. They have identified the key aspects of each framework and made recommendations on how these could be developed for a MOG. This section summarises their recommendations; further details are available in the final WP 7 reports. Key questions addressed include:

- Who should regulate MOG assets?
- What is the ownership structure of the MOG?
- How should a meshed DC network be operated?

4.3.4.1 REGULATORY GOVERNANCE OF THE OFFSHORE GRID

Barrier: Transmission systems are regulated at a national level with bilateral agreements to manage flows over interconnectors. A MOG will significantly increase levels of interconnection and join together more than two countries. To regulate these assets effectively, greater coordination between NRAs and/or a bespoke MOG regulator is needed.

Importance for the MOG: A clear regulatory approach is a pre-requisite for a MOG. Without this it is unlikely that sufficient investment will be raised.

Analysis and Recommendation: National transmission networks are regulated by NRAs who typically determine the revenue received by transmission owners and operators (and the conditions and incentives linked to this). NRAs also determine the quality and safety standards operators must adhere to, the requirement for unbundling of different energy assets and the introduction of competition into markets previously dominated by monopolies.

At a national level the ministry/government department concerned with energy (and/or infrastructure), the energy regulator and the competition authority are three important bodies linked to transmission network regulation. In the federal systems, these institutions may exist at both the central and regional government levels. Alternatively, the regulatory authority and competition authority may be merged into one authority, e.g. in the Netherlands.

At an EU level, the Agency for the Cooperation of Energy Regulators (ACER) assists in coordination of activities across the NRAs, at an EU level, and, providing opinions and recommendations to TSOs, ENTSO-E, ENTSO-G, NRAs, EU Parliament, EU Council and EU Commission on matters relating to cross border energy regulation. ACER is not a European Regulator, but is an EU body responsible for promoting regulatory cooperation and for coordinating NRAs' activities in the EU.

In Deliverable 7.2, four options for MOG governance were examined (Figure 4-8)

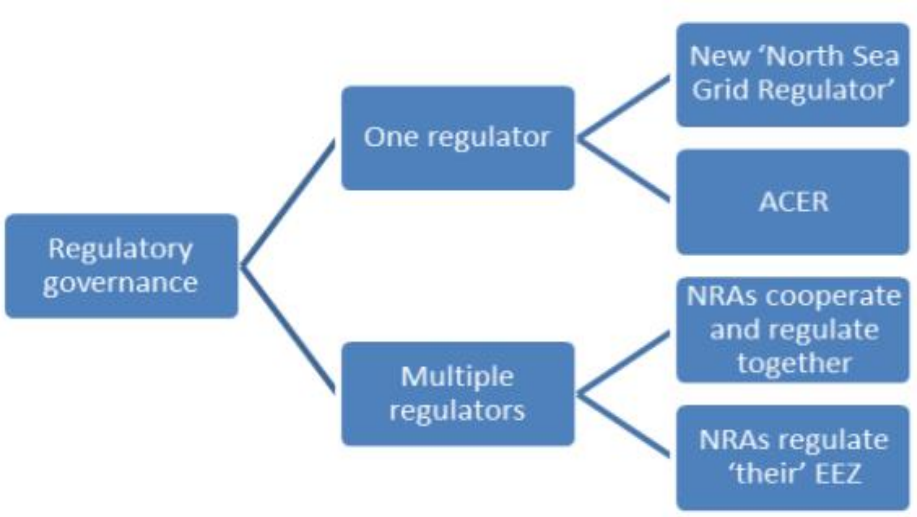


Figure 4-8 - Overview of regulatory governance options (Deliverable 7.2)

Deliverable 7.2 concluded that the cooperation of the national NRAs is the most favourable option to incorporate in the legal framework for the governance of the MOG. It can be delivered more swiftly than other options (it is an extension of existing cooperation arrangements), is likely to be more politically acceptable than setting up a new MOG-wide institution, but can still deliver the benefits of a coordinated approach. The NRAs should agree on transmission tariffs paid by OWFs, the revenue paid to transmission owners, the process for connecting to the MOG and operational requirements such as safety standards and day-to-day

operational rules etc. Such cooperation can evolve over time, if coastal states are willing to increase the amount of cooperation, his could eventually lead to the creation of a de-facto North Sea Regulator.

Recommendation: The agreement of the NRAs to cooperate to regulate the Meshed Offshore Grid should be included in the mixed partial agreement so that it encompasses North Seas countries inside and outside the EU.

4.3.4.2 PROCEDURAL AND LEGAL CERTAINTY

The legal framework for a Meshed Offshore Grid must have clear processes for disputes resolution. Deliverable 7.2 sets out two types of disputes which may occur:

- Horizontal disputes between two commercial parties in the MOG. These are normally resolved via national procedures or via commercial arbitration.
- Vertical disputes between a commercial party and a national government, regulator or EU institution. Resolving these disputes is more complex in the context of a MOG as decisions are taken jointly by various regulatory authorities. These are considered in more detail below.

Deliverable 7.2 considered three options for dispute resolution:

1. the procedures under the ACER Regulation remain applicable to the entire North Sea MOG (via a mixed partial agreement)
2. for conflicts between two EU Member-States, the ACER Regulation and CJEU procedures remain applicable; for conflicts between an EU Member-State and a third states, international arbitration is used
3. if NRAs disagree with each other or with the project developer, international arbitration is used for the entire MOG

Deliverable 7.2 did not reach a firm recommendation of one of the three options, as at the time of writing there was a lack of clarity on the future status between the EU and the UK, and the EU were awaiting an opinion from the European Court of Justice on the extent to which international arbitration procedures which may interpret/give opinions on the interpretation of EU legislation are compatible with EU law itself. The only recommendation possible at the time of writing is that appeal procedures and dispute settlement procedures should be taken into account into an international agreement on the MOG.

4.3.4.3 OWNERSHIP MODELS FOR THE MESHED OFFSHORE GRID

The ownership model for Meshed Offshore Grid assets should be determined by the body/bodies regulating the network. Deliverable 7.6 (Financial Framework) considered 5 different ownership options set out in Table 4-1 below.

Table 4-1 - Ownership models for a MOG

	MODEL	CONSTRUCTION	OWNERSHIP	ASSET MAINTENANCE
A	North Sea Grid TSO[11]	NSG TSO		
B	National TOs (continuation of existing	National TOs (or OWF generators in the UK's case)	National TOs or OFTOs[12] (in the UK)	National TOs or OFTOs

[11] In this case Transmission System Owner and Operator

	MODEL	CONSTRUCTION	OWNERSHIP	ASSET MAINTENANCE
	national ownership models)			
C	Tenders before Construction	Appointed OFTOs. This option would require a system planner or cooperation of planning bodies across North Seas Countries	OFTOs	OFTOs
D	Built by a North Seas Grid ISO, tendered to third parties[13]	North Seas Grid ISO (This entity could be formed of national TOs/OFTOs)	Assets tendered to third parties post-construction	Asset Owner (Third Parties)
E	Built by National TOs, tendered to third parties	National TOs (or OWF developers in the UK's case	All assets tendered to third parties post-construction	Asset Owner (Third Parties)

Each approach was assessed against its ability to deliver a net economic benefit and attract third party investment. The views of stakeholders were also sought. All models were considered feasible provided that they were appropriately regulated such that transmission owners were remunerated for their services. Financial and regulatory stability are key in attracting sufficient third party financing. Therefore, it is important that the regulatory regime provides clarity on how the remuneration of transmission assets changes as their purpose changes (e.g. from interconnector to hybrid asset, or vice versa).

No single ownership model delivered the best results across all categories – Central approaches were considered more likely to deliver investments with high technical standardisation and relatively low regulatory complexity since only one entity is responsible for the whole grid, but they lack competition which could ultimately slow down the learning curve. On the other hand, competitive approaches, where ownership of the grid assets is assigned to third parties through competitive tenders (assuming low entry barriers), competition is introduced which could stimulate innovation. However, under competitive and co-operative approaches where several owners co-exist, higher coordination efforts are needed (e.g. to coordinate planned outages), increasing the regulatory complexity. The impact of each approach on total cost to the consumer is uncertain – competitive pressure should in theory lead to lower costs, but the third parties bidding may not be able to deliver the economies of scale possible if construction is concentrated amongst a few parties14.

Under all options it will be necessary to consider the ability to attract the necessary levels of investment and ensure that they are compatible with EU energy law, particularly concerning rules on unbundling (Deliverable 7.2). Attracting investment is considered in great detail in the section on the financial framework (Section 4.3.3). Finally, the choice of ownership model affects the way the grid is regulated (Deliverable 7.2). If the grid is owned by one entity, it should be regulated as one grid, in order to make sure that the grid is operated and

[12] Offshore Transmission System Owner
[13] Independent System Operator
[14] The evidence on the impact of a competitive tendering approach on consumer costs is mixed. Analysis commissioned by Ofgem (UK NRA) concludes that the OFTO regime (where generators build assets and then transfer them to an OFTO) has saved costs compared to a centralised approach where the offshore network is managed by the onshore TSO (Source: **https://www.ofgem.gov.uk/publications-and-updates/evaluation-ofto-tender-round-2-and-3-benefits**). However, research commissioned by TenneT comparing the German and UK approaches suggested that countries where the grid connection is built by the onshore TSO have lower CAPEX that those where the connection is delivered by the generator (Source: **https://www.tennet.eu/news/detail/dnv-gl-compares-costs-of-offshore-connection-systems/**).

developed in the best way from a regional perspective. With regional ownership of the grid and national regulation, there may be wrong incentives to develop the grid in a certain (nationally oriented) way, even though this is suboptimal from a regional socio-economic perspective. Moreover, if the grid is owned by multiple entities, there should be regulatory decisions for each entity individually, due to the principles of administrative law.

It is concluded that each ownership model has strengths and weaknesses, and there is no consistent preference across stakeholders. The European Commission should have a central role in collating the views of stakeholders and co-ordinate the transition to the preferred ownership model.

4.3.4.4 SYSTEM OPERATION

Barrier: A MOG will connect several different synchronous zones. Once hybrid assets are introduced as connecting elements between synchronous areas, the current System Operation Guidelines (SOGL) will become inadequate to fulfil their scope. The current guidelines cover situations where the only interconnecting elements between synchronous areas are HVDC interconnectors, which, in very simple terms, can be operated as 'electricity pipelines' between synchronous areas[15]. The introduction of hybrid assets demands the capability to control not only the flow at the interconnection points with the HVAC systems onshore, but also the injections from the OWF. If this regular, real-time control fails to happen, the there is a risk to the security of supply onshore which increases in proportion with the extent electricity is generated offshore.

Importance for the MOG: To be operated as a *meshed* grid, coordination of system operation across the MOG is necessary. The approach to this must be agreed by North Sea countries.

Analysis and Recommendation: Deliverable 7.9 considers two options: an independent system operator (ISO) or a regional coordination centre (RCC). Establishing an RCC for the MOG was recommended to coordinate the approach to system operation across all operators in North Seas countries. This option was preferred to the ISO approach as there is already legislation in place to establish RCCs, they are likely to be quicker to establish than an ISO and also more politically acceptable as national System Operators will still retain a say in how the MOG is operated.

4.3.5 REVENUE MECHANISMS FOR OFFSHORE WIND FARMS AND TRANSMISSION OWNERS

In a Meshed Offshore Grid it must be determined how revenue for both OWFs and transmission asset owners is calculated. This section first considers support schemes for OWFs in the context of a MOG. This was examined by both deliverables 7.2 and 7.4 (legal and economic frameworks). Appendix V looks in more detail at the market arrangements which could determine the revenue of OWFs and provides further details on how the administration of support schemes for OWFs may differ under different market arrangements.

[15] Electricity flows across HVDC interconnectors can be modulated at its extremes independently from the flow patterns within the AC systems connected by the cable. This allows a frequency control in each synchronous area independently from each other, and the HVDC cable in between can be used as a 'regulating valve' to exchange excess of generation in one area with its neighbour. In this sense, from an operational point of view, a HVDC cable can be seen as an elementary network connecting other two areas.

This section then considers transmission asset owner revenue and whether specific investment incentives for offshore assets may be appropriate (Deliverable 7.4 and 7.6). It then considers the role of transmission tariffs paid by OWFs in contributing towards the regulated revenue received by grid asset owners (Deliverable 7.4).

Finally this section considers how the costs of these revenue mechanisms can be paid for fairly by consumers in North Seas countries. This would be determined through a cross-border cost allocation (CBCA; Deliverable 7.4).

4.3.5.1 SUPPORT SCHEMES FOR OWFS

Barriers: Current support schemes are designed for OWFs which feed directly into their onshore grid only. There are limited precedents for joint support schemes across North Seas countries. Individual states may be unwilling to support OWFs located in their EEZ when the electricity produced is exported to another country.

Importance for the MOG: A lack of support for OWFs which export to two or more countries (those connected to a hybrid asset) could jeopardise the investment case for new OWFs. To provide certainty to wind farm owners on the support they will receive a consistent approach across North Seas countries is required.

It should be noted that there is an important link between bidding zone design and support schemes because the bidding zone determines the income of OWFs and, thus, to what extent developers need extra support in order to develop OWFs. This is discussed further in Section 2.9

Analysis and Recommendation: Whilst support schemes for OWFs are still in place, cooperation mechanisms for renewable support could overcome potential barriers (Deliverable 7.4). The European Commission has already developed three cooperation mechanisms:

- **Statistical Transfers**: A statistical transfer mechanism enables countries generating more renewable energy than is needed to meet their national targets, to sell this excess production “credit” with countries that are unable to reach their targets. Whilst this mechanism can encourage the development of renewable generation in the most cost-effective locations, unless all countries connected to a MOG are able to trade production ‘credits’ the market is likely to be illiquid and unable to fairly reconcile the amount of renewable generation subsidy spent by each country on MOG-connected OWFs, with the amount of electricity received.
- **Joint Projects**: An agreement between two or more countries to jointly development renewable energy projects. These countries can be either EU Member States or third countries. The subsidies received by the joint project, and who pays for these are negotiated between the countries. The joint auction scheme for PV launched between Germany and Denmark can be considered as an example of cooperation under a joint projects mechanism.

  If applied to OWFs in a Meshed Offshore Grid, all countries connected, or who anticipate being connected, to an OWF would need to be party to the negotiations. This forward-looking approach is to ensure that future development of the Meshed Offshore Grid isn’t restricted by existing bilateral agreements.
- **Joint Support Scheme**: Similar to a joint project, a joint support scheme is an alternative to national renewable support schemes. The participating countries develop a single support scheme applied to all shared assets. A detailed description along with guidance for implementation of joint support

schemes has been published by the European Commission. Norway and Sweden have a joint support scheme.

Deliverable 7.4 recommends further investigation of a technology-specific joint support scheme to harmonise support for offshore wind. 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 through the development of the most cost-effective sites. An example of a joint support scheme in Europe is the joint renewable certificate scheme that has been implemented in Norway and Sweden since 2012. Deliverable 7.2 proposed a similar cooperative approach as a long-term aim of the MOG. Deliverable 7.2 proposed that a regional or EU-based fund support could be established into which states pay based on actual electricity flows from OWFs to their onshore grids. This could be calculated after the fact and is more likely to be considered a fair (and thus politically acceptable) distribution of costs.

In the short-term (prior to any coordination of support schemes across countries), Deliverable 7.2 recommends decoupling physical flows and market flows in support schemes. This would allow OWFs in a MOG to bid into the electricity market of their home country (lowering the wholesale energy market price there) and also receive their agreed subsidy, while the physical flow may go in another direction.

4.3.5.2 REGULATED INCOME AND INVESTMENT INCENTIVES FOR TRANSMISSION ASSET OWNERS

Barrier: If MOG transmission assets were treated as exempted (merchant) interconnectors, their revenues would be based solely on the price differential between the interconnected countries/markets, i.e. congestion rent. The increasing interconnectivity delivered by the MOG would lead to convergence of the electricity prices across markets and consequently to a decrease of congestion rents. Relying on congestion rent is not a viable long-term business model for MOG assets and would struggle to attract investment.

Importance for the MOG: Investment in the MOG will only happen if assets can develop a viable long-term business case. This cannot be delivered if investors are relying on congestion rents, therefore alternative revenue mechanisms are necessary.

Analysis and Recommendations: The revenue received by transmission asset owners is typically set by the NRA. They are based on the tariffs they receive from grid users. Approaches to determine regulated revenue vary between countries. Exempted interconnectors do not receive tariffs but have congestion rents as their sole income.

The configuration of the MOG should be based on the most efficient configuration for offshore wind evacuation and transmission flows, not as a result of the most favourable income structures. A consistent approach should be applied to how the revenue is determined and what investment incentives are applied.

The detailed mechanism by which dedicated investment incentives for offshore assets will form part of the regulated revenue will be dependent on who regulates the Meshed Offshore Grid and the ownership structure of offshore assets. Deliverable 7.6 suggests two possible models:

- Inclusion in the owner's regulated asset base. This is more suited to options A & B under Ownership Models where a North Seas TSO or National TOs own the MOG.
- Where assets are tendered to third parties a fixed revenue (determined following a competitive tender) may be more suitable. This should allow some adjustment mechanisms for performance

incentives and market indicators (e.g. index-linked). This is similar to the OFTO regime used in the UK.

Deliverable 7.4 carried out a qualitative analysis of investment incentives which indicated that application of dedicated incentives can be considered as a valid approach by countries that are likely to require significant investment in offshore grids. Applying dedicated incentives to offshore assets reflects the different risk profile of offshore investments compared to onshore. The application of dedicated incentives can result in a better balance of economic incentives in terms of the trade-off between risks and remuneration. However, when setting investment incentives, regulators must remain aware of the risk of over or undercompensating asset owners due to the complexity of such mechanisms, and the existence of information asymmetry due to a lack of transparency. Deliverable 7.6 (financial framework) reached a similar conclusion following interviews with key stakeholders from across the sector. It found that the regulator should take into account the specific risks associated with offshore transmission investments when setting the revenue for offshore transmission assets. Applying the same framework onshore as offshore is likely to result in an inappropriate allocation of risks and may prevent potential investors from investing in the offshore grid.

4.3.5.3 TRANSMISSION CHARGES PAID BY OFFSHORE WIND FARMS

Barrier: The transmission charges paid by generators for access to the transmission network are not harmonised across Europe; and in some countries generators do not pay for continued access to the grid. For assets connected to more than one country there is no mechanism for calculating their transmission charges.

Importance for the MOG: Transmission charges can be a significant operational expenditure for OWFs in countries where they are applied (e.g. in the UK, OWFs must pay annual Transmission Network Use of System charges). Currently, OWFs are connected to one country's transmission system and will pay transmission charges for that system (where applicable). In a MOG (or any form of hybrid asset), a wind farm will be connected to at least two countries. Clarity on how transmission tariffs are calculated in a MOG is needed to provide certainty to OWF developers of their long-term operating costs.

Analysis and Recommendations: Ultimately, any decision on transmission tariffs would need to be made by the regulator(s) of a MOG. A further pre-requisite for determining transmission charges for MOG-connected assets is a decision on whether the MOG is treated as a single 'zone' for the purposes of transmission charging, or whether each part of the MOG complies to the rules of the country in whose EEZ the OWF falls.

In either case, the current recommendation of the European Commission to move towards harmonised transmission charges across EU member states, including the recommendation in the Clean Energy Package of a European Network code on transmission tariff design, will make it easier to develop solutions for MOG-connected OWFs.

Developing alignment across transmission tariffs will require cooperation from all North Seas countries. ACER already provides a framework for cooperation between regulatory authorities of EU member states. The inclusion of non-EU member states into ACER would only be possible with the agreement of EU members, and it has yet to be determined whether non-EU member states would have voting rights, or simply be observers[16].

[16] http://www.europarl.europa.eu/RegData/etudes/BRIE/2017/614183/IPOL_BRI(2017)614183_EN.pdf

In terms of timings, clarity on transmission tariff design is desirable ahead of the first hybrid asset construction. If this is not possible, bilateral agreements on the transmission tariffs charged to OWFs could be put in place. However, the existence of multiple such agreements would make a unified transmission tariff design across the MOG more complex. Therefore, resolving this issue is considered to be a high priority once the MOG regulator(s) is established.

4.3.5.4 CROSS BORDER COST ALLOCATION

Deliverable 7.4 quotes the TEN-E regulation which state that: “The efficiently incurred investment costs, related to a project of common interest… 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".

This regulation envisages an approach where the allocation of costs of transmission assets (where not recovered through other revenue streams) between nation states is based on the beneficiary pays principle.

Importance for the MOG: The complexity of the MOG could require amendments to current CBCA methods, which are currently typically applied to interconnectors between two countries.

Analysis and recommendations:

Deliverable 7.4 provides a detailed assessment of the key elements of a robust CBCA process and uses case study analysis to assess the extent to which they have been successfully applied to recent interconnector projects. This analysis resulted in four recommendations to improve the robustness of CBCA calculations for Meshed Offshore Grid assets.

1. Coordination of CBCA decisions for complementary projects. This could be achieved by taking a clustered approach in which a CBCA agreement is reached for a group of projects. This would enable robust consideration of project complementarities and mitigate any distortions in the development of the projects.
2. Formalization of the CBCA as a binding contract between the involved parties with clear specification of non-compliance penalties, especially with respect to commissioning dates. In a multi-stakeholder environment, such a step can ensure greater commitment towards the project by all parties, thereby avoiding the construction of “bridges to nowhere”, also called stranded assets.
3. 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 enable effective EU funding allocation.
4. Ensuring complete CBCA decisions. A complete CBCA is one which considers how costs would be allocated between nation states, both with and without a contribution from the EU’s CEF. This is necessary as CBCAs are often carried out prior to a decision on whether CEF funding will be provided to a project. Having to revisit a decision in light of such funding being declined, can result in project delays.

4.3.6 OPERATIONAL FRAMEWORK

The day to day running of transmission networks are governed by a series of codes and market rules. In work package 7, the legal and economic framework considered the extent to which key codes and market

mechanisms would need to adapt to incorporate a Meshed Offshore Grid network. The operation elements considered were:

- Extension of EU Network Codes (Deliverable 7.2)
- Capacity Allocation and Congestion Management (Deliverable 7.2)
- Priority Access and Priority Dispatch for RES in the MOG (Deliverable 7.2)
- SOGL and Emergency & Restoration Code (Deliverable 7.9)
- Balancing Mechanism (Deliverable 7.4)

4.3.6.1 EXTENSIONS OF EU NETWORK CODES

Barrier and importance to MOG: The current EU Network codes are applicable throughout the EU. However, the MOG will also incorporate non-EU states. For EEA countries, such as Norway, the Network Codes will be implemented as well. For non-EU and non- EEA states, implementing these codes may be more politically difficult.

Recommendation: If politically acceptable, a reference to the relevant European network codes could be incorporated into an international agreement, such as the mixed partial agreement proposed for MOG governance (see 4.3.1). In this way, third states would also be bound by the Network codes but not by all other rules. Alternatively, a similar solution as for Switzerland, which is located in the middle of the synchronous continental electricity network, could be sought. Switzerland is not bound by the network codes directly, but several network codes include a specific clause on Switzerland – minimum standards ensure safe network operation.

4.3.6.2 CAPACITY ALLOCATION AND CONGESTION MANAGEMENT

Research suggests that the Capacity Allocation and Congestion Management rules are broadly compatible with a MOG, even if this results in the creation of one or more new bidding zones.

4.3.6.3 PRIORITY ACCESS AND DISPATCH

Under the new rules of the Clean Energy Package, there will be no priority access and dispatch for OWFs. However, a method to decide on curtailment and compensation in case of a capacity shortage in certain line must still be developed. This is difficult for OWFs as they operate with near-zero marginal costs. The implications of transmission line congestion are explored further in Appendix V on market configurations.

4.3.6.4 SYSTEM OPERATION GUIDELINES AND EMERGENCY AND RESTORATION CODE

The SOGL sets minimum system security, operational planning and frequency management standards to ensure safe and coordinated system operation across Europe. This creates a standardised framework on which regional cooperation including balancing markets can be implemented. SOGL sits alongside the Emergency and Restoration code within the 'System Operation' area of the European Network Codes. The SOGL provisions are mostly based on existing AC system operation practices.

If, in the near future, offshore renewable energy sources provide the baseload electricity supply[17], it is not yet clear if the dimensioning of reserve capacity onshore will be bound by the criteria expressed in the SOGL. It is

[17] Assuming a massive reduction in operational coal and nuclear power plants by 2025, as many national energy plans foresee at the date of publication of this report.

also not clear how the baseload provided by the OWF connected to the MOG will be delivered to each onshore market at a transparent, reasonable price. Reserve products might also be broadened with additional products accounting for a quicker system restoration process after major disturbances as frequency quality standards might evolve to account for the stronger dependency on frequency from intermittent generation.

4.3.6.5 BALANCING MECHANISM

Barrier: At a day to day level, the system operator(s) of the MOG and the North Seas countries will need to ensure that supply and demand are matched in real time. As the contribution of intermittent renewables increases, it will become increasingly important to have flexible, responsive balancing mechanisms which can manage intermittent generation. Currently, Balancing Mechanisms differ between countries and not all balancing mechanism services can be traded at an international level.

Importance to the MOG: Intermittent generation is increasingly viewed as an important part of the balancing mechanism of national electricity systems. In a MOG, OWFs may be physically able to contribute to the Balancing Mechanism in two or more countries (provided they are classed as Balancing Supply Parties (BSPs)[18]), but clarity is needed on how these OWFs bid into these markets.

Analysis and Recommendations:

Deliverable 7.6 provides detailed analysis of the Balancing Mechanism from a system perspective and from the perspective of an Offshore Wind Farm as a BSP and as a Balancing Responsible Party (BRP)[19].

The overarching recommendation is that North Seas countries (and other EU member states) continue to work towards developing an integrated balancing mechanism. One example of this is Project TERRE (Trans European Replacement Reserve Exchange) which will allow those national system operators using Replacement Reserve (a balancing service with >15 minute lead time) to exchange energy on a new European Platform.

More specifically, Table 4-2 provides an overview of the preferred approach to different aspects of the balancing mechanism from the perspective of the system and OWFs as both BSPs and BRPs.

Table 4-2 - Summary of the current balancing mechanisms regulation from the three perspectives.

	PERSPECTIVES		
DIMENSIONS	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

[18] BSP – A provider of balancing capacity. The time duration and quantity of capacity provided will be agreed in contracts with the System Operator.
[19] As a BRP, the OWF is responsible for the costs of its own imbalances. In several EU countries, intermittent generation is exempt from being classed as a BRP.

			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)

- **Imbalance settlement rule**: The settlement rule is a financial settlement mechanism for charging or paying BRPs for their imbalances. The amount paid to generators for excess generation can be different to the amount charged for not meeting contracted generation, or these two prices can be equal and opposite (a single price rule). This single price rule for imbalance settlement is the best solution from all perspectives (Table 4-2) as it encourages parties to balance without introducing discrimination against smaller generators as large players can net their imbalances across their generation portfolio and thus reduce their costs. The European Electricity Balancing Guideline also supports this view.
- **Imbalance settlement period**: a conflict between the user and service provider perspective occurs. The system favours a shorter imbalance settlement period as this provides more flexibility to the operator. OWFs as BSPs also favour shorter settlement periods as they have greater certainty over their generation capability over a shorter time horizon. However, when viewed as a BRP, OWFs prefer longer settlement periods to allow more time to net-out imbalances during the period. 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 such 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. Several national system operators are looking to open their balancing mechanism to new players and have introduced new products and contract structures to allow for this. For example, in the UK small generation and energy storage assets can now participate in the Balancing Mechanisms as BSPs through asset aggregators.
- **Scarcity pricing**: A scarcity price for system balancing would reflect the full cost of balancing the system – taking into account the cost of reserving balancing capacity as well as the cost of energy used in system balancing. 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 would also benefit from the better valuation of its services. However, from a balance responsible party perspective, scarcity pricing could be considered as an added risk for OWFs due to their limited ability to respond to price spikes in the balancing mechanism.
- **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. It would allow BRPs to trade out their imbalances ahead of gate closure with greater ease. For BSPs, a liquid intraday market can provide alternative trading opportunities besides participation in the balancing market.
- **Integrating balancing market**: greater integration of balancing markets would be desirable. In their 2011 position paper on 'developing balancing systems to facilitate the achievement of renewable energy goals', ENTSO-E, 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.

4.3.7 DECOMMISSIONING A MESHED OFFSHORE GRID

Deliverable 7.2 examines options for aligning decommissioning guidelines across North Seas countries and ensuring assets which could continue to serve a purpose in an offshore grid remain in place after another asset has been decommissioned.

Barrier: Rules for decommissioning offshore assets vary by country, and often do not account for the fact that some aspects of an offshore wind development may have a longer lifespan than others (e.g. a hybrid transmission asset may continue to be used as an interconnector after the end-of-life of a wind farm).

Importance for the MOG: Different rules in different countries make it difficult to assess the total cost of decommissioning for cross-border projects and add administrative costs. Decommissioning guidelines intended for use on radially connected assets may also result in counter-intuitive decisions where assets which are potentially still useful as part of a MOG are removed from the offshore environment.

Recommendations:

The decommissioning requirements for OWFs should be based on a case-by-case assessment by the relevant permitting agency, during the planning process. However, in general the standard process should be:

- At the end-of-life of a wind farm, the transmission cables may be left in place unless in a sensitive area with high shipping or fishing activity, changeable sea bottom or areas such as the beach. Depending on the grid topology, these transmission assets could continue to be used as interconnectors or to connect a new wind farm built in the same place.
- For wind farms, the permitting agency should decide whether removal of all wind farms assets is required, or whether the foundations can be left in place. This should be decided as early as possible to provide greater cost certainty to developers.
- Any assets which remain in situ after their useful life (and after the owner has discharged their decommissioning responsibilities) should fall under the responsibility of the state provided that the state is compensated for potential future costs, for example through a ring-fenced fund.

To provide consistency on guidelines for decommissioning of offshore wind assets (turbines and transmission assets), guidelines should be agreed upon at an international level such as International Maritime Organisation (IMO) or OSPAR[20]. To inform this, further research into the environmental impact of decommissioning OWFs and offshore electricity cables is necessary. The research in PROMOTioN identified knowledge gaps in the understanding of this topic.

[20] A mechanism by which 15 Governments & the EU cooperate to protect the marine environment of the North-East Atlantic.

4.4 RECOMMENDATIONS ON GOVERNMENT INVOLVEMENT

Government policy will be instrumental in delivering offshore wind in the North Seas. Aside from Governments' role in facilitating the anticipatory investments (see Section 4.2.7) and determining the legal and regulatory framework for OWFs and transmission assets (see Section 4.2.8), Government policy will also influence the development of the supply chain and skilled personnel to work in the sector.

4.4.1 FOSTER THE ESTABLISHMENT OF AN OFFSHORE SUPPLY CHAIN

The development of multi-terminal grids will require the demonstration of new technologies, including those developed during the PROMOTioN project DCCBs, GIS, protection and control systems. Following successful demonstration, supply chain manufacturers will need to significantly scale up production if they are to meet the demand set out in PROMOTioN's High Deployment scenario. Government Industrial Policy can support investment in supply chain infrastructure, such as port facilities, and provide funding for the demonstration of new technologies in a marine environment. It should be noted that any Government support provided must fall within State Aid rules to avoid individual companies being given an unfair advantage.

The tax system can also foster innovation and investment, for example through enhanced capital allowances (accelerated tax relief) for investment in new equipment. Finally, governments can support infrastructure projects by lowering their cost of capital – a significant part of total project spend. In the UK this has been done through the UK Guarantees Scheme, which was launched in 2013, to support energy, transport, housing and social infrastructure projects. Under the UK Guarantees Scheme, projects could apply to the Government for unconditional and irrevocable guarantees of principal and interest in favour of a lender to/investor in a UK infrastructure project and on behalf of borrower/issuers of debt. The project pays a guarantee fee to the Government for this service but benefit from being able to borrow money at the UK Government's credit rating, lowering the project's cost of capital[21].

4.4.2 SUPPORT THE DEVELOPMENT AND TRAINING OF SKILLS

As well as investing in supply chain infrastructure, governments can also support skills development and training to ensure North Seas countries have a sufficiently well-trained workforce to deliver the number of offshore wind projects expected. Training courses and facilities can be developed in conjunction with local and regional governments, education agencies and potential employers (offshore wind farm developers and transmission owners). For example, the East of England Offshore Skills Centre[22] in the UK offers grant-funded courses to train new offshore wind technicians. This Centre is co-located with an existing college and was collaboration between the main local offshore wind employer and local councils, the local enterprise partnership, and the education and skills funding agency. Another example is the National HVDC Centre in Scotland, which was funded by Ofgem (the UK energy regulator, an arms-length government body) following a competition for new innovation ideas. This centre includes state-of-the-art simulation equipment for HVDC networks, and also acts as a training facility for engineers.

[21] https://www.nic.org.uk/wp-content/uploads/Review-of-infrastructure-financing-market.pdf
[22] https://www.offshorewindskills.co.uk/about/

4.5 RECOMMENDATIONS ON MARKET MODELS

4.5.1 ESTABLISH A SMALL BIDDING ZONE MODEL

When a large number of wind parks are developed in the North Sea, a choice will need to be made as to how to remunerate them. When wind parks become connected to more than one country, it is not a given that the best choice is to pay them the electricity market prices of the countries in whose EEZ they are located. Power that is generated by offshore wind parks may not always flow to the countries in whose zone they are located. From the perspective of the European integrated electricity market, the objective should be to generate renewable energy in the most economically efficient manner and to transport it to where the added value is highest, regardless of national policy targets and boundaries[23]. With this in mind, there are multiple ways in which the offshore wind electricity market could be designed in a multi-terminal grid configuration. Three options have been considered in a numerical analysis, comparing the performance of the different pricing systems with respect to economic efficiency and welfare effects. This has been carried out by TU Delft and is provided in full in in Appendix V. The three options are:

- **Option 1: national price zones.** The national price zones are extended into the North Sea in accordance with the EEZs of the North Seas countries. This means that wind parks receive the electricity price of the onshore price zone in which they are located. This option is the status quo.
- **Option 2: a single offshore price zone.** A new price zone is created at sea. This encompasses all wind parks that are connected to the MOG on the North Sea. The idea behind this option is that when the MOG becomes more developed, the national prices and the zonal configuration based on the countries' EEZs become arbitrary. A single offshore zone could be a simple solution.
- **Option 3: many small price zones.** By defining price zones with the size of individual OWFs or small clusters of parks, the prices will reflect the local marginal cost of generation. This will avoid some of the key disadvantages of the other options.

Splitting the meshed offshore grid into small price zones, while returning the congestion rents to the wind farm operators, appears to be the most attractive market design for a meshed offshore grid. The price zones would be defined by the existence of network congestion, like in Nordpool. Wind farms without congestion between them would receive the same price. This model can be implemented from the start of the development of a meshed offshore grid, when most parks have single connections to the shore. In this phase, the results will resemble the national price zone model. However, when the offshore electricity network becomes meshed, and in cases where electricity is stored and/or converted to another energy carrier offshore, it becomes necessary that the local electricity price offshore reflects the local marginal value of electricity. National price zones do not provide this incentive and may cause situations in which economically efficient dispatch would require trading power from a high price to a low-price zone. A single offshore price zone avoids the latter, but still does not provide efficient incentives for power conversion.

A degree of over-dimensioning of the wind parks, as compared to the grid capacity, is rational because it increases the utilization rate of the network. (However, in PROMOTioN, the goal has been to avoid

[23] The Fourth report on the State of the Energy Union (Brussels, 9.4.2019, COM(21019) 175 final) states these objectives in nearly the same words. The Renewable Energy Directive also stresses the importance of a well-functioning internal energy market for the economically efficient integration of renewable energy (DIRECTIVE (EU) 2018/2001 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 11 December 2018 on the promotion of the use of energy from renewable sources).

curtailment altogether by providing sufficient network capacity.) A disadvantage of allowing congestion is that congestion reduces the revenues of the wind park operators. The research by TU Delft proposes to compensate the wind farm operators for these congestion costs by allocating contracts for differences to them for the difference between their offshore zonal market price and a reference onshore price. This improves the business case for offshore wind and reduces the need for financial support, while maintaining the economic efficiency of the price signal.

The research carried out by TU Delft made certain assumptions, as a result of which the economic efficiency of the dispatch of generation is not affected by the choice of pricing rule. This is the case if the wind parks require subsidy, if network congestion is handled efficiently onshore as well as offshore, and if the onshore markets are organised efficiently. A result of these assumptions is that the generation dispatch and network flows are the same under all reviewed pricing rules, as a result of which the prices in the onshore price zones are also the same in all examples. The differences lie in the revenues of the wind parks and the network operators. In these examples, this is a zero-sum game: lower revenues for the wind park operators mean higher congestion revenues for the network operators and vice versa. At first glance, one might conclude that there is not much difference, therefore, but:

- It may be difficult to reallocate congestion rents to wind park operators, e.g. through subsidies, as the TSO(s) that collect these rents may be privately owned and not necessarily in the same country as the one that provides financial support to the wind parks.
- Lower market revenues for offshore wind parks entail a higher need for financial support.
- All market designs other than one with small price zones (or locational marginal pricing) discourage investment in flexibility options such as energy storage and power-to-gas within the meshed offshore grid.

From a legal perspective there are no major impediments to the small bidding zone model in EU law. Instead, EU law promotes an organization of the bidding zones according to structural congestions, which makes the small price zones model more appropriate than the other models from a legal perspective. In order to allow for the contracts for differences, some national legislation on the organization of support schemes will have to be changed.

5 STAKEHOLDER ACTIONS FOR THE DEVELOPMENT OF A MESHED OFFSHORE GRID

Please note that this Chapter will be updated in Deliverable 12.4

5.1 INTRODUCTION

The PROMOTioN project has advanced technologies from early stages of development to a level where they are ready to be demonstrated in marine environments and commercialised. There has been extensive research into the Legal & Regulatory frameworks that exist and how these may need to change to allow for multi-terminal offshore networks. This chapter focuses on the Stakeholders who need to be involved in auctioning the recommendations made in PROMOTioN.

The PROMOTioN team has already had an impact in amending the legal framework for offshore transmission – WP7 identified the need for a legal definition of offshore hybrid assets, lobbied for the inclusion of a definition in regulation, and were successful in seeing its inclusion in the recitals of the EU's 2019 Clean Air Package. This Chapter takes the recommendations made in Chapter 4 and allocates them to different stakeholders. Actions are split into short-term and long-term.

5.2 STAKEHOLDERS

Key stakeholders that are involved in the development of HVDC offshore grid are listed in Figure 5-1. Some of the stakeholders actively participate in the main stages of the offshore grid development. For each of those stakeholders, a small description is presented, after which the recommendations for each are given. These recommendations are conveniently split according to the short-term and long-term recommendations as described below. Note that not all stakeholders that are listed in Figure 5-1 below. All those that are identified in PROMOTioN are described in Appendix IV.

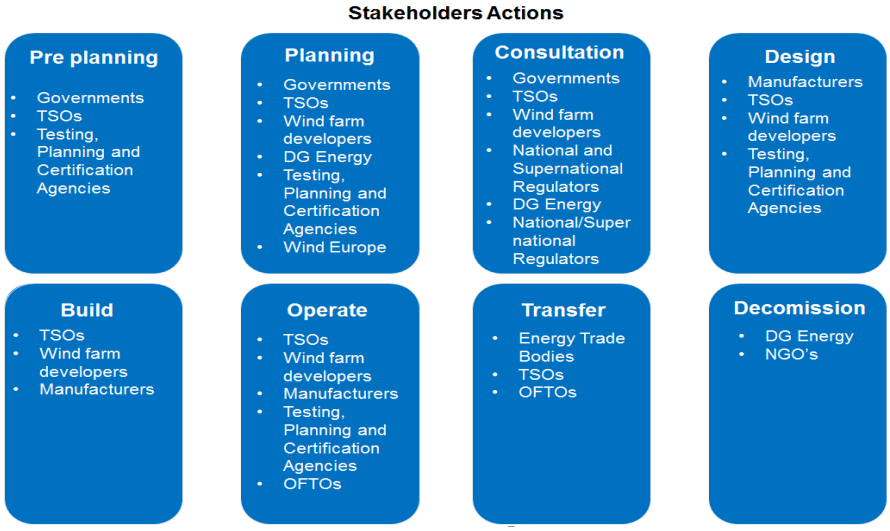


Figure 5-1 Stakeholders in the HVDC offshore grid

5.2.1 EUROPEAN COMMISSIONS DIRECTORATE-GENERAL (DG) ENERGY

The objective of DG Energy is to create a competitive internal energy market in order to lower prices, to develop renewable energy sources, to reduce energy consumption and to reduce energy dependence. Therefore, below are presented long term and short term recommendations that DG Energy should take into account in order to achieve these objectives.

5.2.1.1 SHORT-TERM ACTIONS

Legal Framework

In the short term, it is recommended that DG Energy amend (Recast) the Regulation on the internal market for electricity in order to include a definition and substantive provisions on how an offshore hybrid asset should be regulated. Moreover, in the near future DG energy should nominate experts that will regularly check technical developments, understand their value for the power system and design legislative and regulatory measures to favour system upgrades.

5.2.1.2 LONG-TERM ACTIONS

In the long term, it is recommended that DG Energy are a party to the mixed partial agreement setting out the process for cooperation and decision making amongst north seas countries.

Support for OWFs

In the short term, DG Energy should facilitate the development of joint support schemes between countries connected to hybrid assets to ensure that the cost of supporting OWFs is shared fairly between countries benefiting from their power. If in the long term, the market adopts the small bidding zones configuration recommended by PROMOTioN in Section 4.5 and DG Energy should work with North Seas governments to adapt support schemes for OWFs (if still existent at that time) to the nodal pricing regime.

5.2.2 GOVERNMENTS/MEMBER STATES

Government member states are one of the most important stakeholders required to champion the development of a MOG and enable its integration with national onshore networks.

This is a result of the fact that they are responsible for issuing permits and political aspects that have to be in place before the start of the construction. Therefore, it is crucial to give them specific recommendations that can make the permitting process more compact and easier to implement. Besides the recommendations given here, section 4.4 presents recommendations for governments regarding collaboration, environmental and financing aspects.

5.2.2.1 SHORT-TERM ACTIONS

In the short-term, governments can enable regulatory authorities and other public bodies to engage with their equivalent organisations in North Seas countries to increase levels of cooperation and coordination across OWF planning and regulation, and to start to establish the framework for a North Seas regulator involving the cooperation of national regulatory authorities.

To develop the legal framework for the MOG, in the short-term, governments in EU member states can transpose the definition of offshore hybrid asset into domestic legislation. In the longer term, all North Seas

Governments should develop and sign up to a mixed partial agreement (a North Seas Treaty) setting out the legal and regulatory frameworks for the MOG and the process for cooperation between countries.

In addition, governments can work together to streamline the planning and permitting processes, for example through creating a one-stop-shop for key project permits to reduce the number of permits, shorten the process for acquiring the permits and the number of authorities involved. This approach is highly recommended because it has many advantages; for the project developers, the complexity is reduced; for the government, it leads to more efficient handling of the case and possibly more specialization concerning offshore projects. This joint approach could also extend to Environmental Impact Assessments (EIA), where a joint approach could consider the cumulative impacts of a development across more than one jurisdiction.

LONG-TERM ACTIONS

One of the long term recommendations for governments and member states is the adoption of a North Sea treaty for the Member-States, third states, and EU. This will provide; common interpretation of relevant UNCLOS provisions, aims, and principles of the MOG. Other long term actions are linked to governance and decision-making structure. The most important of them are listed below:

- Long term OWF and grid planning (geographical and temporal, in a similar way as the TYNDP process)
- Regulatory Governance; formalise the cooperation between North Sea NRAs
- Decision-making; yearly conference of parties where long-term decisions are made
- Delegation of tasks to committees of national experts; alignment of construction rules; technical rules (e.g. network codes); cumulative environmental impact
- Legal certainty; formalise decision-making process and appeals procedures
- Use a nodal pricing bidding zone configuration. This requires impact assessment and mitigation of the consequences for certain parties, and adaptation of the support system

5.2.3 NATIONAL AND SUPRANATIONAL REGULATORS

5.2.3.1 SHORT-TERM ACTIONS

Regardless of the grid owner, regulation of the transmission activities is necessary. Cooperation between the NRAs of North Seas countries is the recommended option for setting a regulatory framework for multi-terminal offshore networks. The NRAs should determine the tariffs, access regime, safety standards, etc. For the offshore hybrid assets connected in a MOG, income should be based on regulated income rather than on congestion revenue.[24]

5.2.4 NATIONAL PLANNING AUTHORITIES

National planning authorities should work increasingly closely to develop long-term plans for offshore wind siting, in order that anticipatory investment in the transmission network can be identified. To reduce the complexity of the planning and permitting process, a one-stop-shop for key project permits should be created to reduce the number of permits, shorten the process for acquiring the permits and the number of authorities

[24] This conclusion is also supported from the financial perspective. See A. Armeni, G. Gerdes, A. Wallasch, L. Rehfeldt 2019, *supra* note 60, chapter 3.6.

involved. Where planning processes in neighbouring countries are similar, this permitting process for both countries could be joined and covered by one planning application. This approach has many advantages; for the project developers, the complexity is reduced; for the planning authority, it leads to more efficient handling of the case and possibly more specialization concerning offshore projects. A pilot project to test the extent to which countries can coordinate their planning and permitting processes for offshore projects should be carried out to learn lessons for the future.

5.2.5 TSOs

In some countries, TSOs are responsible for the design, build, and operation of the offshore grid. In others, this role is split between transmission owners (design, build and maintain) and a system operator for the national transmission system, In the UK, OWF developers design and build the transmission connection from their wind farm to the onshore network. The role of the TSO is very important and thus it must fulfil a list of recommendations that are crucial for the success of the project. These recommendations concentrate on grid planning, technology, operation and control, the protection system and legal and regulatory aspects.

5.2.5.1 SHORT-TERM ACTIONS

In the short term the existing role and responsibilities of TSOs in the offshore environment is likely to persist. In some countries the onshore TO is responsible for building offshore assets, while in others (notably the UK) there are specific OFTOs.

The designed grid provides reliable and stable energy supply. Therefore, it is advisable for TSOs to follow recommendations regarding transmission capacity and voltage, reliability and interoperability. According to reliability suggestions, TSOs must ensure that a single contingency cannot lead to an undesirable disturbance in the onshore grid, e.g. a load shedding. Following a single contingency, TSO has to guarantee that the loss of power infeed for a determined zone will be below the reference incident of that zone (Appendix III), and the global loss of power infeed in all zones will be below the maximum value of all the reference incidents in the various zones (i.e. in Europe 3000 MW).

Transmission and capacity recommendations strictly suggest for TSOs to keep voltages at all nodes at normal conditions between 0.95 and 1.05 p.u. Apart from this, it is recommended to design interconnection capacity between countries at a lower level than the maximum loss of active power injection in one of the connected areas (e.g. UK 1.85 GW). Subsequently, TSOs must focus also on interoperability aspects. While selecting manufacturers that will supply equipment for the project it is recommended to choose those that can ensure that their devices can work with existing technologies without any interruption. TSOs must guarantee that the designed grid is technically feasible, hence not only grid planning aspects have to be fulfilled. Selected devices must cooperate with each other and have to be controllable.

5.2.5.2 LONG-TERM ACTIONS

In the longer term, the regulatory framework for the meshed grid will need to establish the ownership model(s) for meshed offshore grid assets.

TSOs have to guarantee that operational and control criteria for; onshore AC system, offshore generation, offshore consumption, operation and control, of the offshore meshed grid are achieved. A detailed list of these recommendations is presented in Chapter 4 and Appendix III. These tips contain values for frequency

ranges, active power controllability, the maximum loss of active power, voltage ranges and reactive power controllability. Moreover, there are suggestions about fault ride-through capability (the main requirement for robustness, which refers to the ability of PGM to remain connected to the power system during short periods of over-voltage or under voltage [5]) energization, and synchronization of the grid. Besides, there are recommendations on operation and control requirements that have to be abided by TSOs for the start-up of HVDC terminals, robustness and stability of the whole grid.

During the operation of the grid, TSOs must fulfil the protection system recommendations. It is strictly recommended for TSOs to guarantee that the DC grid protection system will not operate in case of power flow changes during normal operation (e.g. power order change). Moreover, TSOs must ensure that DC grid protection system is reliable regardless of changes in the grounding schemes, like variation of grounding location, metallic/ground return operation of a bipolar configuration.

5.2.6 WIND FARM DEVELOPERS

OWFs developers are often consortia of companies than plan, build and operate OWFs. Therefore, offshore developers follow recommendations regarding grid planning, protection system and operation and control of the Meshed Offshore Grid.

During the design phase of the OWF, developers have to strictly collaborate with TSOs to agree a suitable connection point to the TSOs network (this could be onshore or offshore depending on the location of the OWF). Both stakeholders are responsible for the stable, reliable and affordable operation of the wind farm. Therefore, it is recommended for wind farm developers to follow interoperability and reliability recommendations. The significant issue that they have to solve is the selection of these manufacturers whose products are interoperable between vendors and technologies during the lifetime of the equipment. Besides this, the most important operation and control recommendations for the offshore grid are the ones connected with offshore generation (e.g. post – fault recovery). A detailed list of requirements for offshore generation is presented in Appendix III of this document.

5.2.6.1 SHORT-TERM ACTIONS

Firstly, during the design process OWFs developers should ensure that their connection to the network does not result in voltage distortion or fluctuation at the connection point [5]. Besides, it can be agreed that short term recommendations turn to such requirements like maximum power point tracking system, which is one of the offshore generation requirements. This system is delivered by wind turbine manufacturer so it can be agreed that this action will be performed in a short term e.g. during the commissioning of OWFs. Another offshore generation requirement that is regarded as a short term action is a start-up capability. OWFs have to perform essential control actions in collaboration with offshore HVDC terminal in order to start-up offshore grid.

5.2.6.2 LONG-TERM ACTIONS

Long term actions focus on operation and control requirements. Functions like operational rate of change of frequency, DC voltage response, or frequency response processing are strictly connected to reliability and stability of OWFs, so they are performed as a long term action. These recommendations are fulfilled after commissioning of the grid, hence are not the priority like interoperability or start up capability.

5.2.7 MANUFACTURERS

Manufacturers are involved in the design, build and the supply of offshore infrastructure. Their influence is on planning, interoperability, and technology. Therefore, they have to follow grid planning recommendations that are given in Appendix III.

5.2.7.1 SHORT-TERM ACTIONS

The key issue for manufacturers is to supply devices that are interoperable. For this clarity on the grid requirements is necessary (e.g. through a HVDC Grid Code developed by the NRAs).

Manufacturers also have to implement operation and control recommendations. For example, wind turbine generators have to be equipped with a maximum power point tracking function that is provided by the producer. The maximum power point tracking function is one of the power control and frequency stability requirements for the Meshed Offshore Grid.

5.2.7.2 LONG-TERM ACTIONS

Manufacturers have to ensure that they are able to adapt their devices into changing conditions during the lifetime of the equipment. This is why it is recommended for them to publish some basic sets of relevant data (measurements, signals). This can help in solving common problems since some issues most probably will arise during the lifetime of the wind farm.

5.2.8 OTHERS

5.2.8.1 LONG-TERM ACTIONS

PROMOTioN recommends that decommissioning guidelines are adopted at an international level by IMO/OSPAR. The content of these guidelines should build on experience of decommissioning assets in the North Seas and its impact on the environment.

6 CONCLUSIONS

Moving towards a more sustainable energy supply requires ambitious actions on both the demand side and the generation side. The objective of PROMOTioN is therefore to progress in developing a MOG that may have a substantial influence on designing a greener European Union. In order to develop this MOG, a set of recommendations has to be taken into account.

The multi-criteria evaluations that were performed lead to recommendations about concepts that are deemed to be most suitable for implementation. In order to assign the stakeholder actions to a specific time period, each recommendation is grouped under the specific period of grid development in which it is necessary and an indication is made of the time required to implement the recommendation. The status of progress on the action outside the PROMOTioN project is also given, distinguishing between no action taken, action ongoing but not yet finalised and action finalised. The stakeholders that have an interest in each recommendation are also given. An overview of the recommendations per period is given in the sections below and summarised in Figure 6-1.

6.1 THE PERIOD 2020 – 2030

By 2030 roll out is limited to current practices, except for the use of 2 GW HVDC components that are not yet used today. Already in the early stages of grid development, the establishment of an offshore HVDC grid code can ensure meshing of the grid in later periods. It will allow grid developers to independently develop the offshore grid according to similar characteristics, allowing for meshing in later periods. In order to facilitate the deployment of DCCBs in later periods of grid development, an onshore DCCB pilot project should be setup. The PROMOTioN pilot project short term project allows for integration of a DCCB in a setting where testing can be facilitated in a real-life environment where the tests have little to no influence on the reliability of the environment it is tested in. Similarly, a GIS pilot project can be setup and GIS technology may be deployed already in early stages of the grid. Due a long regulatory lead-time up to the construction of an island hub, the hub may only start implementation by 2030, with only a short period between construction and operation once the regulation is settled.

As much of the offshore grid is still similar to the current offshore grid many current regulations may still apply in this period. However, as a minimum, bilateral agreements will be required to agree the regulatory framework and/or the support scheme for the connection of some OWFs that are only connected to other countries than in which EEZ they are located. These situations could not be managed under ‘business as usual’ regulation. The integration of these bilateral agreements into a future regulatory regime for the MOG would be much smoother if at this stage the key principles of MOG regulation and how regulatory decisions will be made across the North Seas had been agreed in the *North Sea treaty* as well as the definition of an offshore hybrid asset. An alternative to the hybrid asset classification may be delivered in the form of the small bidding zones, as already establishing a small bidding zone for the OWFs omits the necessity for a hybrid asset classification. Due to some locally meshed configurations, anticipatory investments must already be allowed in some North Sea countries, where the choice to build far offshore already early in the entire period is more logical.

Combining the OWFs to reach a critical size of 2 GW also entails the alignment of connection costs for OWF developers in the North Seas countries. In order to fully capture the opportunity to mesh early in the period, the CBCA methodology for meshed projects should also be completed in this period, allowing for the correct allocation of the costs and benefits of cross-border meshed configurations. Governments and Industry should be investing in supply chain and personnel development to facilitate the increased rate of deployment expected in later years. An overview of the actions in this period is made in Table 6-1.

Table 6-1 - Actions, their timing and the stakeholders in the period 2020 - 2030

ACTION	PREP.	IMPL.	NEC.	PROGRESS	IMPLEMENTER	INFLUENCER	USER
2GW 525 kV DC technologies	2020	2022	2025	Ongoing	TSOs/ OFTOs	Manufacturers	TSOs/ OFTOs
Interconnection meshing	2020	2025	2030	Ongoing	TSOs/ OFTOs		TSOs/ OFTOs
Island hub	2020	2030	2032	None	TSOs/ OFTOs	Governments	TSOs/ SOs
HVDC grid code	2020	2025	2030	Ongoing	ENTSO-E	TSOs/ OFTOs/ ACER/NRAs	TSOs/ OFTOs
Onshore DCCB pilot project	2020	2022	2025	Ongoing	TSOs/ OFTOs/ EU	TSOs/ OFTOs/ PROMOTioN/ manufacturers	TSOs/ OFTOs
Offshore DCCB pilot project	2022	2025	2028	Ongoing	TSOs/ OFTOs/ EU	TSOs/ OFTOs/ PROMOTioN/ manufacturers	TSOs/ OFTOs
GIS pilot project	2020	2022	2025	Final	TSOs/ OFTOs/ EU	TSOs/ OFTOs/ PROMOTioN/ manufacturers	TSOs/ OFTOs
GIS deployment	2025	2025	2027	Ongoing	TSOs/ OFTOs	PROMOTioN/ manufacturers	TSOs/ OFTOs
Anticipatory investments	2020	2025	2027	Ongoing	TSOs/ OFTOs	Governments	TSOs/ OFTOs
Small bidding zones – asset alternative	2025	2029	2030	Final	NRAs	TSOs/ OFTOs	TSOs/ SOs
Offshore hybrid asset	2020	2028	2030	Ongoing	EU		TSOs/ SOs
Connection costs alignment	2020	2025	2030	None	Governments	NRAs	TSOs/ SOs/ OWF developers
CBCA for meshed projects	2020	2025	2030	None	EU	TSOs/ OFTOs	TSOs/ SOs

6.2 THE PERIOD 2030 – 2040

As the rate of grid development increases over this period, the DCCBs necessary for protection should be ready for deployment. This is done through the pilot projects in the previous period. Although possibly important in other stages of grid development as well, it is especially necessary for technologies to be interoperable when meshing of the grid becomes complex. As more and more HVDC offshore technologies are deployed throughout the period, the technology will become standardised in order to save costs.

If small zones regulation is not yet applied as an alternative to hybrid assets, the configuration of the offshore grid will have become too complex to be able to regulate the bidding zones as an extension of the home bidding zone. The bidding zones regulations should therefore be implemented in this period.

During this period some early offshore wind assets will be decommissioned. It would therefore be useful to have decommissioning guidance agreed across North Sea countries before the end of the period.

The period also marks a large increase in the deployment rate of offshore wind capacity, which means that a dedicated supply chain should be established by this time. This also indicates a large opportunity for governments to increase the employment rate of skilled personnel in their countries.

Due to the complexity of the meshing, the remuneration of assets as it is regulated nowadays will no longer be viable. Therefore, if support is still required, this should be done through a joint support scheme. Similarly, aligned permitting should be implemented at the end of this period, as well as the remuneration regulation. These both could first be piloted in less complex meshed situations in the period before 2030, when meshes are still relatively straightforward. The actions for this period are summarised in Table 6-2.

Table 6-2 - Actions, their timing and the stakeholders in the period 2030 - 2040

ACTION	PREP.	IMPL.	NEC.	PROGRESS	IMPLEMENTER	INFLUENCER	USER
Interoperability	2020	2030	2035	None	EU	Manufacturers/ TSOs/ OFTOs	TSOs/ OFTOs
Offshore DCCB deployment	2028	2030	2035	None	Manufacturers		TSOs/ OFTOs
Small bidding zones	2035	2039	2040	Final	Governments/ NRAs	TSOs/ OFTOs	TSOs/ SOs
Decommissioning	2035	2035	2040	None	Governments/ NRAs	Manufacturers	Manufacturers/ TSOs/ OFTOs
Supply chain	2030	2030	2035	None	Governments	Manufacturers	Governments
Joint support schemes	2025	2030	2035	None	Governments/ NRAs	TSOs/ OFTOs	OWF developers
Aligned permitting pilot project	2025	2030	2035	None	Governments/ NRAs	TSOs/ OFTOs	OWF developers
Remuneration regulation pilot project	2025	2030	2035	None	Governments/ NRAs	TSOs/ OFTOs	OWF developers

6.3 THE PERIOD 2040 – 2050

By this point, the offshore HVDC grid should be well established. As complexity of the grid increases it may be an opportunity to explore the benefits of connecting smaller meshed grids to create a highly complex meshed grid. However, PROMOTioN analysis found that these grids will be very difficult to properly control. A potential application of DC/DC converters will therefore then have to be explored, which can be used to control the DC power flow. Without this control, the natural flow of DC power could be different than expected which could lead to potentially dangerous situations. Due to the current Technology Readiness Level (TRL) of DC/DC converters, research into this technology will have to begin from 2020 onward, all the way up to this period. See Table 6-3.

Table 6-3 - Actions, their timing and the stakeholders in the period 2040 – 2050

ACTION	PREP.	IMPL.	NEC.	PROGRESS	IMPLEMENTER	INFLUENCER	USER
DC/DC converters	2025	2045	2050	None	Manufacturers		TSOs/ OFTOs

6.4 THE PERIOD 2020 – 2050

Some recommendations will run from the start up to the end of the analysed period. This includes the interaction with flexibility, which has not been researched within PROMOTioN. Therefore, this should be further explored throughout the grid lifetime. Additionally, the protection strategy may be further researched and adjusted throughout the entire lifetime of the grid, as all kinds of protection strategies may be applied in portions of the grid. Refer to Table 6-4.

Table 6-4 - Actions, their timing and the stakeholders in the period 2025 - 2050

ACTION	PREP.	IMPL.	NEC.	PROGRESS	IMPLEMENTER	INFLUENCER	USER
Interaction with flexibility	2020	2020	2050	None	Manufacturers		TSOs/ OFTOs
Protection strategy	2020	2020	2050	Ongoing	TSOs/ OFTOs	Manufacturers	TSOs/ OFTOs

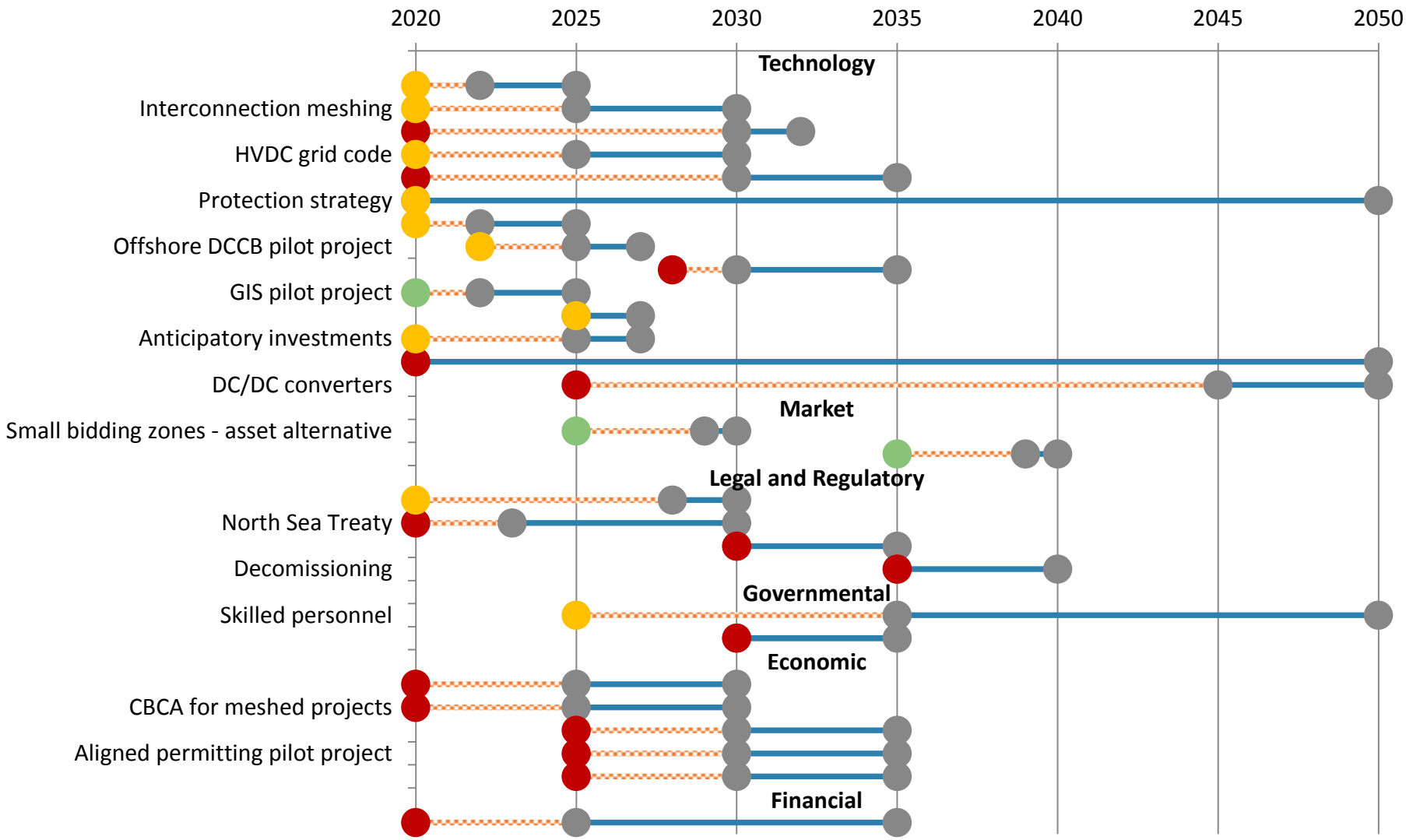


Figure 6-1 - Overview of the recommendations and their timings

[1] WindEurope, "Offshore Wind in Europe - Key trends and statistics 2018," 2019.

[2] ENTSOG and ENTSO-E, "TYNDP 2018 Scenario Report," 2018.

[3] European Commission, "Guide to Cost-Benefit Analysis of Investment Projects," 2014.

[4] ENTSO-E, "Regional Investment Plan 2017 - TYNDP 2018," ENTSO-E, Brussels, 2017.

[5] O. G. J. N. S. A. A. P. E. S. B. Nouri, "Comparison of European Union Grid Codes for HVDC- and AC-Connected renewable Energy Sources," Technical University of Denmark, Roskilde, 2019.

[6] M. Tsili and S. Papathanassiou, "A review of grid code technical requirements for wind farms," *IET Renew. Power Gen.,* vol. 3, no. 3, pp. 308-332, Sep. 2009.

[7] ENTSO-E, 14 April 2016. [Online]. Available: http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32016R0631&from=EN.

[8] E. Csanyi, "Electrical Engineering Portal," 2 12 2016. [Online].

I. APPENDIX - GRID CONCEPTS

To understand the costs and benefits of HVDC meshed networks, three different meshed grid concepts were developed during the PROMOTioN project. These differ in their design philosophy but are all plausible grid development scenarios. The costs and benefits of developing each of these were assessed as part of the CBA and compared to a fourth concept, Business as Usual. This appendix details the design criteria and philosophies behind each concept.

These three meshed grid concepts are not the only way a meshed offshore grid could develop; the eventual development of the grid could use elements of all three. However, the PROMOTioN consortium agrees these three meshed grid concepts plus the Business as Usual scenario covers a broad enough range of possible solutions to draw conclusions on the benefits of meshing in the North Seas.

BUSINESS-AS-USUAL

The current method of connecting OWFs to shore is by radial connections. Wind farms are directly connected to shore, either individually or grouped into clusters. For short distances AC transmission assets tend to be used; longer distances use DC lines. Connections between the electricity grids of different countries are made by dedicated interconnectors (e.g. BritNed, NEMO etc.). The Business as Usual (BAU) concept is shown in Figure 3[25] and contains no new technologies or configurations compared to today's offshore network.

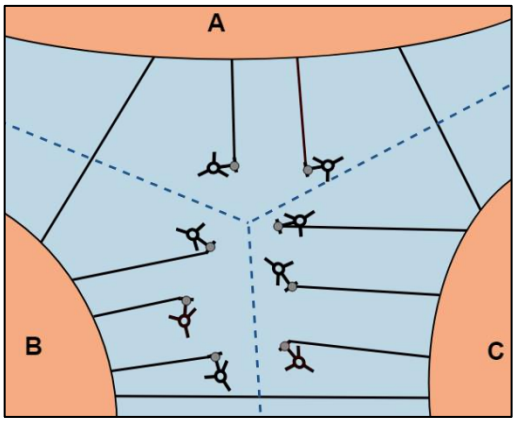


Figure 3 - Business as Usual design philosophy

NATIONAL DISTRIBUTED HUBS

The National Distributed Hubs concept (NAT), Figure 4, is based on a national approach to offshore grid policy and as such does not assume full cross-border cooperation. As in the present, the scope of the national offshore grid is first and foremost to evacuate the generated wind power in the EEZ of the respective country. The national grids may also be strategically connected to each other through bilateral projects, thereby establishing interconnection capacity during low wind energy generation conditions. However, the grid architecture is typically not founded on them.

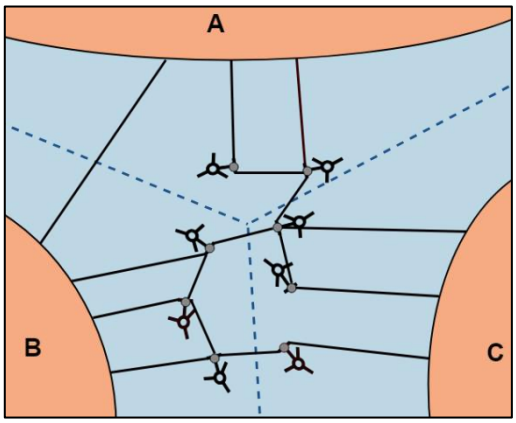


Figure 4 - National Distributed design philosophy

NAT uses offshore hybrid assets, transmission cables connecting two countries, to which OWFs are also connected. Where OWFs of two countries are closer to each other than the countries themselves, it might be more economically efficient to connect the windfarms instead of the countries. Coupling the different national grids

[25] N.B.: The figure does not represent actual proposed locations bur rather how such OWFs would be connected in this concept.

via existing windfarms in each country is only technically feasible if they operate at the same voltage[26]. Separate point-to-point interconnectors are also deployed where more economical than offshore hybrid assets.

NAT also allows for meshing within an EEZ, meaning that multiple OWFs in one country can be connected to one another through a DC connection. This can have two benefits. Firstly, two OWFs might connect to each other and share a larger, more economic cable to evacuate power to shore. Secondly, groups of OWFs might be connected in a ring-like structure resulting in multiple routes to shore for power generated and network redundancy when an individual link is unavailable. At present this structure is relatively new; the only interconnector with a similar structure[27] is Kriegers Flak Combined Grid Solution between East Denmark and Germany via German and Danish[28] OWFs.

EUROPEAN CENTRALISED HUBS

The European Centralised Hubs concept (HUB) proposes the creation of several central hubs, in order to maximise economies of scale for installation costs. These central hubs have two main benefits: reduced capital cost and the possibility of increased interconnection. The cost reductions are driven by a reduction in offshore support structure costs. Support structures are a major cost-driver for offshore wind development, as placing large and heavy structures far into the sea is expensive. Building an island hub is expected to reduce costs compared to an equivalent capacity of offshore platforms.

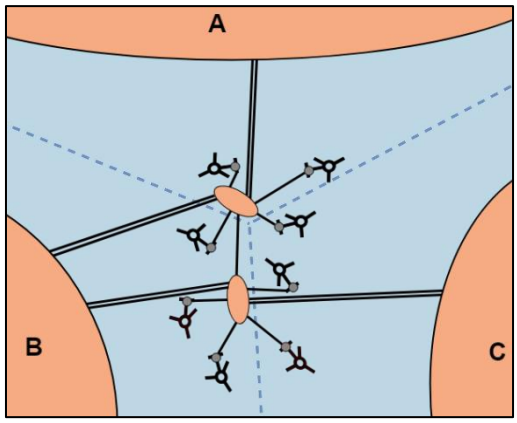


Figure 5 - European Centralised design philosophy

This structure proposes short-distance AC connections from OWFs to these hubs, as is currently done with close to shore connections. A DC grid between the island and the various shores would be constructed to evacuate the energy to land. Such a hub could be very large (up to 40 GW), and therefore will have multiple cable connections, probably with multiple countries. This yields the second benefit: interconnection. The design philosophy, showing only two central hubs, is shown in Figure 5.

Initially, the DC connections require only basic DC technologies as these are point-to-point connections from a hub to a country. They are interconnected via the hub's AC system, to create alternative pathways between countries and from OWFs to different countries. This means that a hub need not be technically complex. However, a hub could be a good test bed for various DC interlinking options.

Multiple hubs could be constructed in the North Seas. These could, but need not, be connected to one another.

EUROPEAN DISTRIBUTED HUBS

The European Distributed Hubs concept (EUR) is designed based on a strongly connected decentralised strategy. Relatively small sized platform-based hubs are spread out over

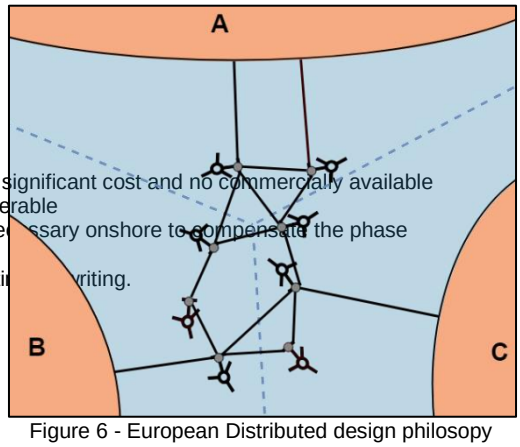


Figure 6 - European Distributed design philosopy

[26] Technically it is feasible with DC/DC converters, but these come with a significant cost and no commercially available reference so far. Connecting same voltage grids is therefore strongly preferable
[27] The offshore grid itself will be in AC and back-to-back converters are necessary onshore to compensate the phase differences between Germany and Denmark.
[28] The Danish OWFs and the interconnector are in commissioning at the time of writing.

the North Seas and connected to each other via HVDC connections, as is illustrated in Figure 6. National borders are not taken as a restriction, which results in relatively low cost hybrid interconnectors, as in the NAT concept. EUR allows for more flexible and technically optimal connections without restrictions on what should be connected to what location. To do this, it requires advanced DC grid technologies such as DCCBs and DC protection systems. The result is a highly resilient grid, where built-in ring structures provide alternative pathways in case of a cable failure. However, the load flow in the resulting meshed DC-network cannot be fully controlled by the existing converters anymore. This technical constraint needs to be taken into account by network design. This is the most technically advanced concept and is similar in design philosophy to the onshore grid, although many differences still exist such as current type (AC vs. DC), use of subsea cables as opposed to overhead lines and the level of redundancy.

II. APPENDIX - MULTI TERMINAL OFFSHORE GRID COMPONENTS

An offshore grid consists of various components which can be divided into primary, secondary and tertiary components. This appendix first introduces key components and their acronyms before providing more in-depth explanations of some of these components.

AN HVDC SYSTEM

Figure 7 shows a simplified HVDC system, which consists of an onshore AC system, an offshore DC system and an offshore AC system. The converter systems manage the AC to DC and DC to AC conversions which are connected by a DC transmission line (DCL). This point-to-point example does not include DCCBs. In future, a meshed offshore DC grid, where more than two converters are connected by a DCL, will require the use of DCCB technology installed at required DC busbars in order to disconnect specific lines. Table 5 summarises all elements used in Figure 7 and their abbreviations.

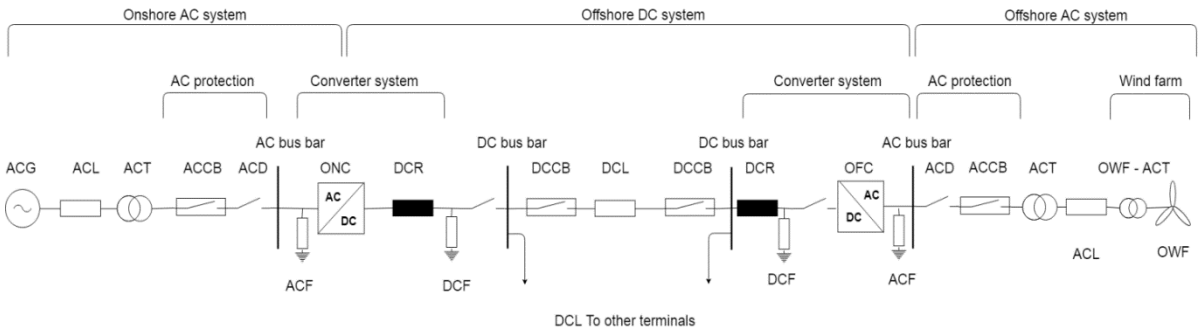


Figure 7 - Representation of an HVDC system

Table 5 - Components of an HVDC system

Abbreviation	Name	Description
ACG	Alternating Current (AC) grid	A meshed network using Alternating Current. Onshore grid systems predominantly use AC, and these will connect directly to the offshore grid.
ACL	AC line	AC transmission line. This can be an overhead line or underground/subsea cable.
ACT	AC transformer	A transformer is used to increase or decrease the voltage on an AC system. Often seen as a part of converter system.
ACCB	AC circuit breaker	A form of protection, enabling 'breaks in the network' to isolate electrical assets. In an AC/DC interface, this would protect the connecting AC side of the converter.
ACD	AC disconnector	An AC disconnector isolates the converter from the AC system.
ACF	AC filter	AC filters reduce harmonic content from the AC grid.
ONC	Onshore converter	Connects the offshore DC grid to the onshore AC grid.

Abbreviation	Name	Description
DCR	DC reactor	A DC reactor is installed to reduce high frequency harmonics the rate of rise of a fault current.
DCF	DC filter	DC filters reduce harmonics content from the DC grid.
DCD	DC disconnector	A DC disconnector isolates the converter from the DC transmission system.
DCCB	DC circuit breaker	A DC circuit breaker protects the connecting DC line or converter by electrically isolating it.
DCL	DC line	This can be an overhead transmission line or underground/subsea cable.
OFC	Offshore converter	An offshore converter connects the DC offshore grid to the AC offshore or onshore grid.
OWF-ACT	Offshore windfarm transformer	A transformer is used to increase or decrease the voltage on an AC system. In this case it is used to increase the voltage from inter-array AC voltage to AC transmission voltage (i.e. 33/66 kV to 150 kV).
OWF	Offshore Wind Farm	-
Control and protection systems		
Type	**Name**	**Description**
Local	AC protection	Protection system that protects the converter station at AC side.
Local	Converter system	Control and protection system that facilitates operation of the converter.
Local	DC protection	Protection system that protects converter station or DC line in case of a failure in the system
Local	Wind farm	Control and protection system that facilitates operation of the wind turbine.
System	Onshore AC system	Control system that facilities operation of the AC grid as a whole
System	Offshore DC system	Control system that facilities operation of the DC grid as a whole, e.g. power flow control or control of the grid topology
System	Offshore AC system	Control system that facilities operation of the AC grid as a whole

PRIMARY COMPONENTS

Primary components are those which are directly needed for the transport of power. Their main function is to provide uninterrupted power flow from the generator to the onshore grid. The primary components include:

- Converters - Within PROMOTioN two key types of converters are considered; VSCs and DRUs. This appendix looks at both and how they may be configured.
- Transformers
- Cables (DC and AC).

CONVERTORS

The role of power converters in the offshore grid is to control and process the flow of power by supplying currents and voltages in a form that is suitable for further transport of power or infeed into the onshore grid. Converters are used to invert polarity, decrease or increase voltage, convert AC to DC or vice versa. Within PROMOTioN two key types of converters are considered, VSCs DRUs. Which converter is applied depends on the grid topology. Another converter type, thyristor based LCC, is not in scope of PROMOTioN as it is considered only to be suitable in a point-to-point link between strong AC grids.

VOLTAGE SOURCE CONVERTER

The VSC generates AC voltage from DC and vice-versa. The advantages of VSCs are that it is possible to control output voltage, control reactive and active power independently, and control frequency, magnitude and phase angle. In addition, HVDC-VSCs are able to regulate the current flow and reverse it thanks to the regulation of the DC side voltage. Therefore, the VSC has a big advantage over DRUs, as it can be used in both radial and meshed topologies. This means that in the PROMOTioN project VSCs can be implemented in a branch that will connect OWFs or that will allow power exchange between countries through the offshore grid. This cannot be provided by DRUs since diodes conduct power only in one direction.

However, VSCs have two significant disadvantages compared to DRUs. Firstly, the VSC is more expensive. Secondly, a VSC has a higher mass than a DRU. This is an important limitation for the installation of VSC on offshore platforms, whose cost significantly increases when volume and weight of the components on top increase. VSCs can be installed in a Half Bridge (HB) or Full Bridge (FB) submodule (SM) formation.

HALF BRIDGE

The HB-SM includes two IGBTs[29] (S1 and S2) and a capacitor C_{SM}. It is possible to achieve positive SM voltage by inserting the capacitor into the arm. Bypassing the capacitor results in a “zero” submodule voltage. The HB-SM is therefore not able to generate negative voltages. Consequently, HB-Multi-Modular Converters (MMCs) cannot over-modulate or block current when a DC fault occurs. In the case of a DC fault, the IGBTs of the HB are blocked and the antiparallel diodes experience a high surge current. Taking into account the fact that the surge current capability of the diodes is rather small, the switch L_S and DC inductance (L_{DC}) have to be designed to limit the fault currents.

FULL BRIDGE

Full bridge modules, on the other hand, are able to generate negative voltages. This is thanks to two extra IGBTs (Figure 8) in comparison to the half-bridge MMC. As a result, blocking of a full bridge MMC can result in a disturbance of the DC fault current.

[29] (IGBT) is a three-terminal power semiconductor device which has no moving parts. Basically used as an electronic switch which, as it was developed, combine high efficiency and fast switching. An IGBT works through the semiconductor component, thus changing its properties to block or create an electrical path.

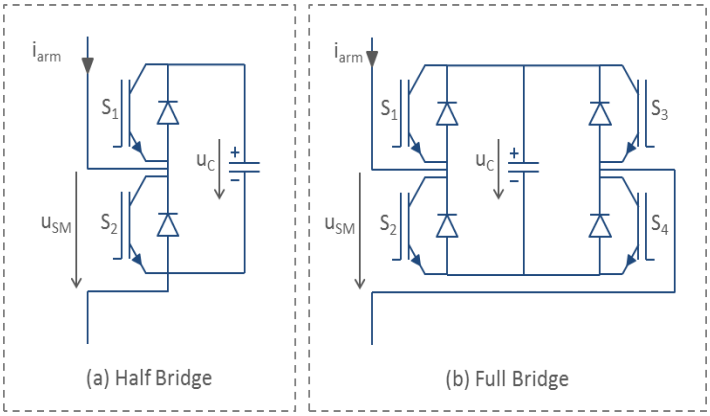


Figure 8 - Half bridge and full bridge topology

DIODE RECTIFYING UNIT

DRUs are the latest achievement in HVDC power transmission. DRU-HVDC systems have the advantages of modular design, high reliability and reduced operation and maintenance costs. Replacing a VSC on an offshore station by a DRU results in a considerable reduction of mass, volume and transmission losses (Figure 9). Moreover, a significant decrease in cost can be achieved as well.

Within the PROMOTioN DRUs can be used only for OWFs connected radially (point-to-point) to the shores. This is a result of the fact that the DRU is technically a rectifier and not a full converter and thus can convert only form AC to DC. Therefore, the DRU's application has its limitations. Using diodes is therefore not possible when providing energy exchange between countries through the offshore grid or when interconnecting OWFs. As the use of DRUs has not been officially proven in a meshed situation, it was decided by the PROMOTioN consortium to only describe its use qualitatively and not take it into account in the CBA.

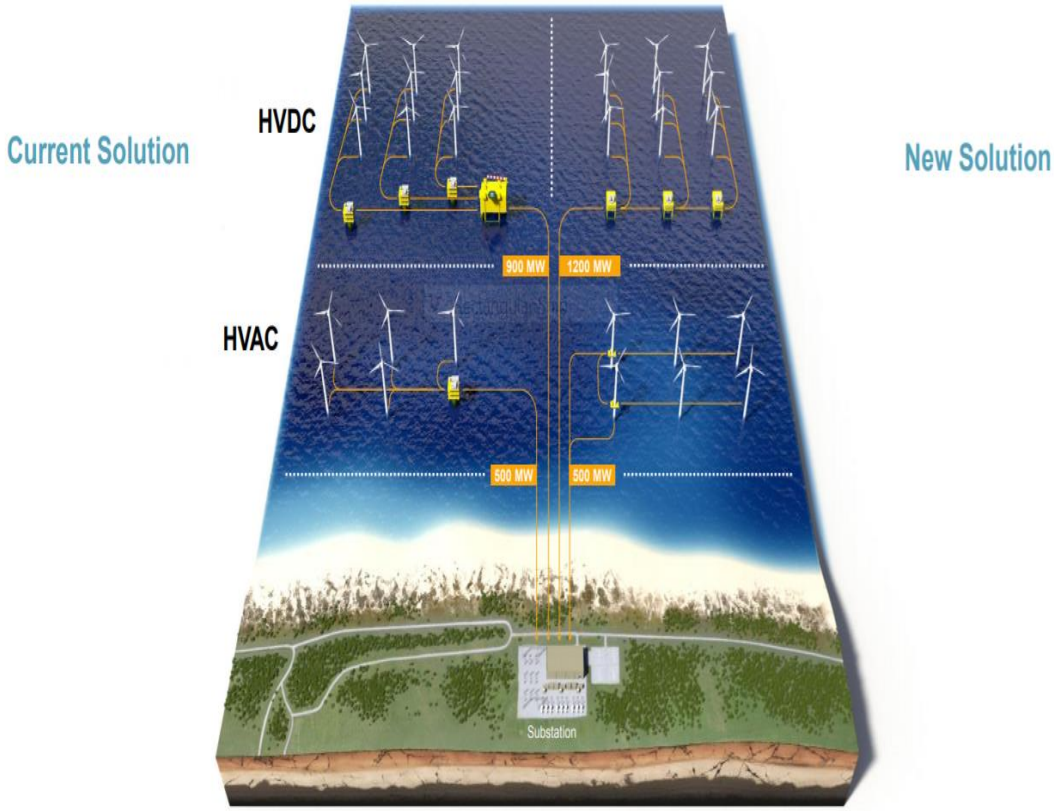


Figure 9 - Comparison of VSC and DRU connection

CONVERTER CONFIGURATION OPTIONS

Performance and operation of an offshore HVDC grid also depends on the configuration of converters and cables that have been used. The following sections describe:

- asymmetric monopoles;
- symmetrical monopoles;
- biopoles; and
- monopole and bipole hybrids.

ASYMMETRIC MONOPOLE

An asymmetric monopole grid configuration operates with one HVDC cable and a low voltage return conductor grounded at one converter station. It is possible to achieve an asymmetric monopole using a single cable with a real earth return but this is prohibited in some countries. Such a solution requires permission from the North Seas countries due to negative environmental effects because of injected energy into the sea bottom. It is high possibility that such permission will not be received for Northern Seas which is why this configuration is not further considered in PROMOTioN. Therefore, a solidly earthed low voltage return cable is normally required as illustrated in Figure 10.

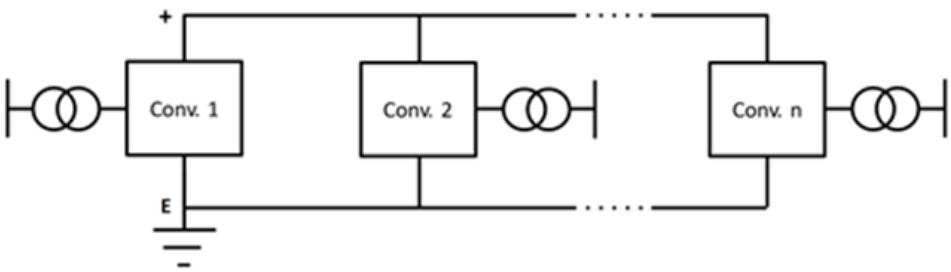


Figure 10 - Asymmetric monopole

Taking into account the same pole-to-ground voltage level, the transmission capacity is a halved while comparing to the symmetrical monopole described below. It is beneficial to replace one HVDC conductor with a low voltage return conductor since then voltage of converters is 50% lower. Because of its asymmetrical operation, the converter transformers experience DC stress.

SYMMETRICAL MONOPOLE

The symmetrical monopole configuration connects the DC side of converters between two high voltage cables of the same magnitude but of opposite polarity as illustrated in Figure 11. This configuration provides double the power rating of an asymmetric monopole system with the same voltage magnitude and can be achieved without additional insulation requirements. The earth reference can be provided in many ways, through the stray capacitances of the DC cable, or through dedicated DC capacitors with its midpoint connected to earth, or via high resistance inductors on the AC side of the converters. There is inherently no redundancy built into either type of monopole system, meaning a fault anywhere within the system, either on one of the cables or converter stations will result in loss of full power transfer capability of that grid section.

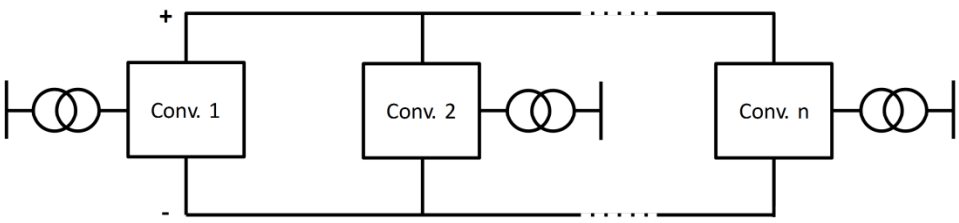


Figure 11 - Symmetrical monopole

BIPOLE

The bipole configuration makes use of two converters connected in series at each terminal, one connected between the positive pole and a neutral midpoint and the other connected between the midpoint and the negative pole. In balanced operation no current flows through the midpoints which are connected via a low voltage metallic return conductor as illustrated in Figure 12.

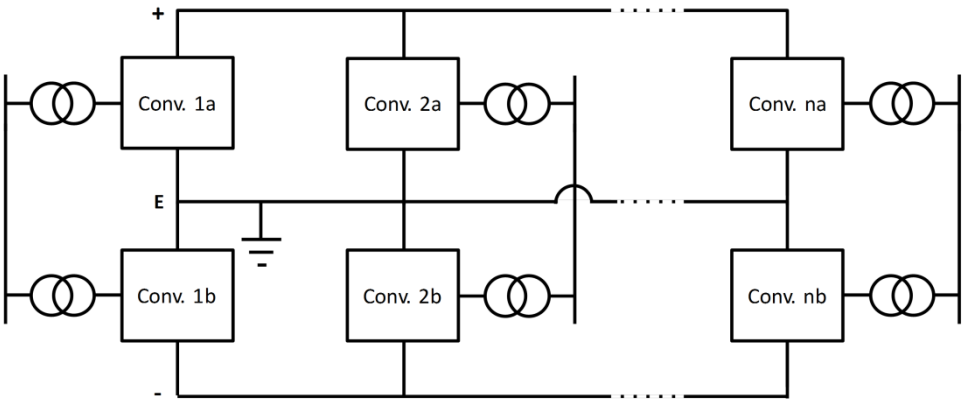


Figure 12 - Bipole

For a given rated pole voltage and current, the power transfer of a bipole is double that of the asymmetric monopole and equal to that of the symmetrical monopole. However, bipole systems provide an inherent redundancy allowing for continued but reduced transmission capability to be utilised by switching to monopole operation under single pole cable or converter fault conditions or maintenance outages. It is also possible to implement a ‘rigid bipole’ configuration in which one end of the bipole is earthed at the midpoint but there is no metallic return cable in which DC neutral current can flow. Such a design allows reconfiguration to monopole operation in the event of a converter pole fault, through use of the healthy pole cable, but any cable faults will result in the entire bipole being tripped. This configuration offers a compromise between the economy of the symmetrical monopole and availability of the full bipole configurations.

MONOPOLE AND BIPOLE HYBRID

It is technically feasible that different converter configurations could be adopted within the same multi-terminal HVDC system with asymmetric or symmetrical monopole configured branches tapping into bipole configured branches as shown in Figure 13. However, such configurations would impose limitations on the design of converters to ensure compatibility. A symmetrical monopole converter tapping into a bipole configuration would, for example, need to be able to work with the full pole-to-pole rated voltage, while an asymmetric monopole tapping would operate at half that voltage. Existing two-level or HB-MMC VSC converter designs which would commonly be used for symmetrical monopole implementations cannot do this.

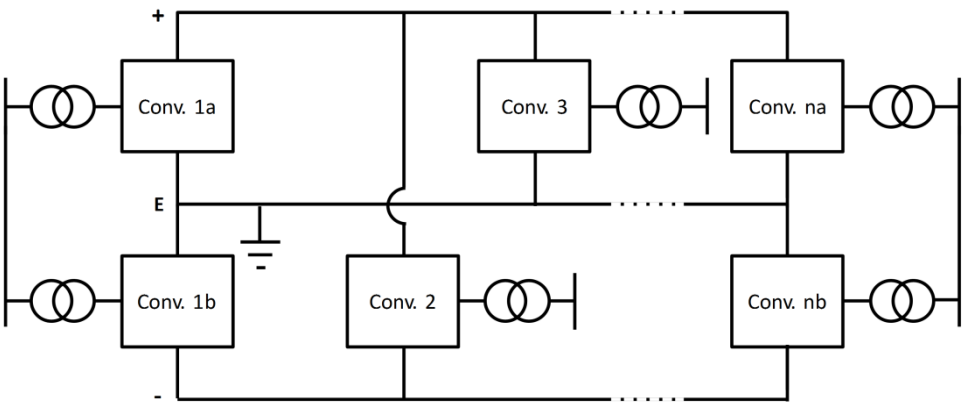


Figure 13 - Bipole configuration with asymmetric and symmetrical monopole tappings

It is technically feasible that different converter configurations could be adopted within the same multi-terminal HVDC system, with asymmetric or symmetrical monopole configured branches tapping into bipole configured branches as shown in Figure 14. However, such configurations would impose limitations on the design of converters to ensure compatibility. A symmetrical monopole converter tapping into a bipole configuration would, for example, need to be able to work with the full pole-to-pole rated voltage, while an asymmetric monopolar tapping would operate at half that voltage. Existing two-level or HB-MMC VSC converter designs which would commonly be used for symmetrical monopole implementations cannot do this. Therefore, in PROMOTioN these converter configuration options cannot to coexist in the grid. Instead the semi-flexibility and economic benefits of bipoles are used.

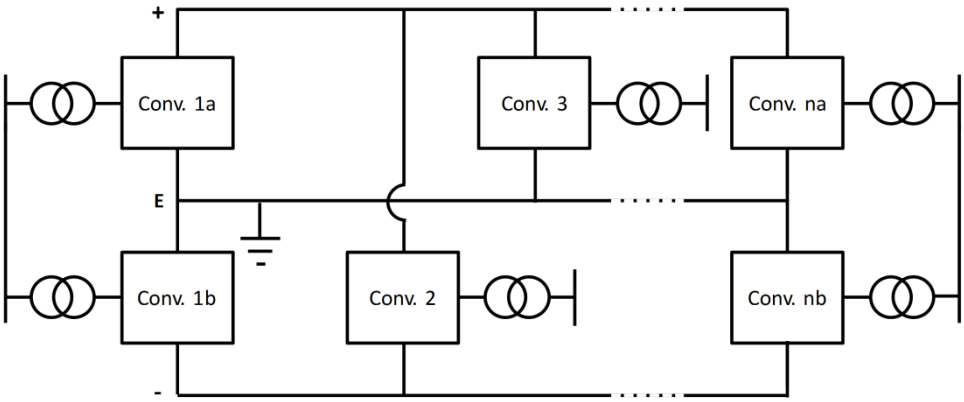


Figure 14 - Bipole configuration with asymmetric and symmetrical monopole tappings

TRANSFORMERS

Transformers in OWFs can be considered as a link between OWFs and the grid. The main role of transformers is to step up (boost) the low output voltage from the OWF to the higher level voltage of the distribution grid. There are both AC and DC transformers.

AC TRANSFORMERS

Within the PROMOTioN project each OWF will produce power at low voltage AC (66kV), which will need to be transported to a platform or hub in order to be converted to DC. Recent development in the offshore sector has seen the elimination of AC transformers for any distance under 50 km. Any distance over this figure requires a higher voltage to overcome the cable's resistance. This transfer then occurs with higher voltage AC, with the

power being transformed by local AC transformers. These transformers are located on small platforms very close to the park.

DC TRANSFORMERS

DC transformers or DC to DC converters will be essential in stepping DC voltage up or down, but they also may have many other functions. For instance, many DC-DC transformers can work as DC circuit breakers and fault current limiters. In particular, DC to DC converters provide an alternative solution for some DC grid topologies. DC to DC transformers might facilitate power exchange between different DC topologies, i.e. monopolar and/or bipolar systems. They could meet other requirements like power control, voltage control, regulation of DC harmonics, energization and start up, and integration of a wide range of existing DC systems. However, given their current TRL, these are not considered in PROMOTioN.

HVDC CABLES

The main limitation of the offshore grid voltage level comes from cables. The PROMOTioN project mainly considers large sized XLPE (Cross-linked Polyethylene) cables. Mass-impregnated cables are not taken into account since, as stated in Deliverable 2.1, XLPE cables are less expensive and more robust compared to mass-impregnated cables. Many companies can furnish XLPE HVDC cables for 525 kV, therefore PROMOTioN considers XPLE cables of 525 kV to be the standard cable used within a near future offshore grid. Although, cables and converters in the future might have even higher voltages and could therefore transport even more power, this is not assumed in the PROMOTioN analysis. This is due to the fact that individual parts should not transfer more than maximum allowable infeed loss.

The maximum allowed loss of infeed power is constrained by the maximum available reserve of an AC system. This is connected to the maximum active power principle that the system can survive without affecting its stability. The maximum infeed loss of power generation units, including HVDC terminals that feed the network is 3 GW in continental Europe, 1.85 GW in the UK, 1.4 GW in Nordic countries and finally 0.7 GW in Ireland. As grids are interconnected, a single voltage is preferable over multiple voltages as this will eliminate the need for transformers and therefore reduce costs. However, multiple sub-grids are built in parallel and different voltages may coexist if the grids are not interconnected. Due to the size of the OWFs built and the different maximum infeed losses in different regions of the North Seas it is therefore chosen to standardise the voltage of the North Sea to 525 kV. The Irish Sea and the Channel is considered, also because of the lower OWF potential and therefore individual size, to transport power at 320 kV.

SECONDARY COMPONENTS

Secondary components are the devices which support and control the work of primary components. The main function of secondary equipment is to keep the power system in stable, uninterrupted conditions. This is done by isolation of components that are damaged or under fault while keeping as much of the grid as possible still in operation. This section will look at:

- DCCBs
- Intelligent Electronic Devices (IEDs)
- Measuring equipment
- Protection Gear
- Switchgear (Gas and Air Insulated)

- Busbars
- Phase shifters
- Grounding
- Choppers

DIRECT CURRENT CIRCUIT BREAKERS

The main role of the circuit breaker is to protect an electrical circuit from damage caused by short circuit or overload. Its basic principle is to operate immediately after detection of a fault condition by the relay and, by interrupting continuity, to rapidly disconnect electrical flow. Within the PROMOTioN project two types of DCCBs are considered; mechanical and hybrid DCCBs.

In the PROMOTioN project it is assumed that DCCBs will only be installed on cables that could, in the case of a failure, cause a potential loss of power infeed in the onshore AC zone higher than the reference incident for that zone (3 GW in continental Europe, 1.85 GW in the UK, 1.4 GW in Nordic countries and finally 0.7 GW in Ireland) or on nodes that could potentially propagate a failure leading to such a loss of power.

MECHANICAL DCCB

A mechanical circuit breaker protects a circuit from currents which are too high. The principle behind a mechanical circuit breaker is based on winding the live wire around a piece of iron. Such behaviour creates an electromagnet. The higher the current in the grid, the stronger the electromagnet. The electromagnet is located in such a way so that it pulls against a switch that can break the circuit. It is designed so that when the current is bigger than some rated value, e.g. 20 A, the switch is pulled open by the magnet and the circuit is broken. Mechanical DCCBs are relatively cheap and compact but they are slower than the electric circuit breaker, described below. Within PROMOTioN, a substantial reduction of costs could be achieved by implementing mechanical DCCBs which are considerably cheaper than hybrid solutions. Moreover, it is worth to mention that for their installation, dedicated platforms are not needed which significantly reduces cost. Currently, the HVDC mechanical circuit breakers have the voltage ratings of 70-80 kV. In order to achieve voltage levels considered within PROMOTioN (320kV-525kV) multiple modules units will have to be connected in series. This mechanism of upscaling of the mechanical circuit breakers is quite complex but still feasible, this is why research is still in progress.

ELECTRONIC DCCB

Electronic circuit breakers are faster than a mechanical one, but very expensive and have high standing losses. This results in a high cooling demand due to power electronics equipment. Their principle of working is based on breaking the current by increasing the resistance in the power electronics.

HYBRID DCCB

Hybrid DCCBs are a good solution for HVDC due to their operating times (less than 5 ms) and their low fault interruption times. They consist of three parallel paths as depicted in Figure 15; a load current path (NCP), communication path (CCP) and an energy absorption path (EAP). The load current path is made up of a mechanical switch that is used to conduct load current without producing excessive losses. The communication path mainly consists of fully controlled semiconductor devices, like IGBTs, used to interrupt fault currents without

an arc.[30] Finally, the EAP is composed of metal oxide varistors and is used to limit the voltage across the DCCB and dissipate residual energy into the grid. This happens when the capacitor voltage overcomes a given value, which is selected as the voltage capability of the circuit breaker, at which point the energy absorption path will act causing the current to decrease.

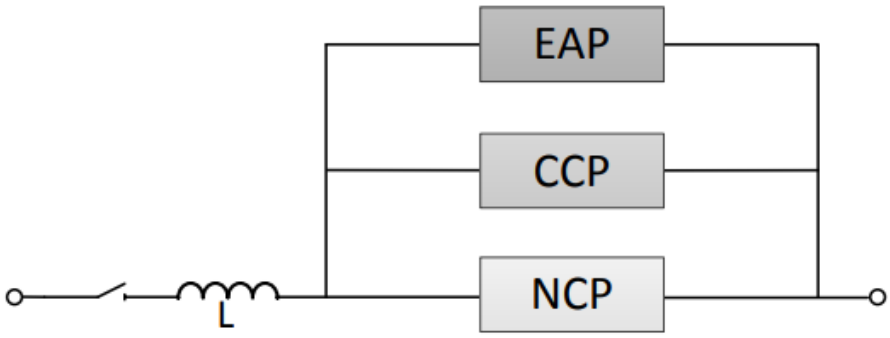


Figure 15 - General structure of a hybrid DC breaker

The cost of the hybrid circuit breakers is quite high and if they were used on every interconnecting line would significantly increase the overall cost of the system. However, their reaction times are also fast which is beneficial in HVDC power transmission.

FULL-BRIDGE VSC

As described previously, the FB VSC is able to block a DC fault current due to the existence of four IGBTs. Therefore, full-bridge converter is selected over the half-bridge in higher power ratings.

INTELLIGENT ELECTRONIC DEVICES

Intelligent electronic devices (IEDs) are a part of power regulation. IEDs use advanced technologies that make two-way digital communication possible where each device on the network has sensing capabilities to collect significant data from the grid. Within PROMOTioN, thanks to the connections with IEDs, a wind turbine controller may adjust a large number of equipment (motors, valves, switches) inside a wind turbine. IEDs can also transfer information to the wind farm control data centres. In addition, IEDs can divide the orders from the control centre to the devices in order to adjust wind turbines. Concerning the tasks of IEDs for wind farms, there are different IEDs connected with a controller, e.g. transformer IED, line IED, bus IED, etc. Utilising computer-based remote control and automation, these devices can be efficiently controlled and adjusted at the node level when disturbances and changes to the grid occur. Additionally, IEDs communicate among each other, allowing distributed intelligence to be applied in order to achieve faster self-healing methodologies and error identification.

[30] The arc-electrical spark created between movable and fixed electrode when they are separated during a fault. The electrical spark occurs because of the flow of free electrons which are formed by ionizing the medium between to electrons. The arc results in considerable usage of the contacts in the mechanical circuit breaker and can be danger for environments with explosive gasses.

MEASURING EQUIPMENT

Measuring equipment, instrument transformers, are required as an input for the IEDs to decide if there is a fault in a grid, and whether breaking is necessary. In order to do this, current (fault current) and voltage (voltage drop) are needed in a measurable form. Therefore, instrument transformers are used. Their main functions are stepping down current or voltage to measurable values that instruments and relays can handle. They are therefore used as insulation of the metering circuit from the primary high voltage system. There are two types of instrument transformers: current transformers and voltage transformers. Current transformers are used to step-down current with regard to both current and phase. They are usually used as inputs to current-powered instruments. Voltage transformers generate a secondary voltage that is proportional to the primary one but differs in phase.

PROTECTION GEAR

Protection gear is a mix of circuit breakers and electrical disconnect switches. This type of equipment is required for the security of the offshore grid. Protection gear is used to clear faults downstream by securing and isolating electrical equipment and to ensure that in cases of a single failure this will not lead to a detrimental effect on the onshore grid. This is done so by recognising faults and isolating faulty components. Eliminating these components ensures the stability of the rest of the system, thereby making it possible to continue operation.

SWITCHGEAR

Switchgear is needed for OWF operation. The switchgear allows the connection of the turbines to the infield power collection and the connection of many strings of turbines to the offshore connection point. Switchgear allow parts of the grid to be isolated. To prevent arcing, the switchgear are designed to suit the insulating material used. The following sections describe gas and air insulated switchgear.

GAS INSULATED SWITCHGEAR

GIS is small metal-encapsulated switchgear made of high-voltage components like disconnectors and circuit breakers. GIS is smaller than air insulated switchgear, making it suited to offshore platforms where space is limited. In GIS, the insulating gas is SF_6, which has global warming potential 23,500 times higher than carbon dioxide. Therefore, within PROMOTioN WP15 is researching other gases with similar insulating properties that can replace SF_6.

AIR INSULATED SWITCHGEAR

In AIS the main circuit potential is insulated from the ground by air. AIS contains such components like surge arrestors, circuit breakers, disconnecting switches (disconnectors), capacitors, busbars, etc. All devices are connected to each other by stranded flexible conductors, power cables or tubes. AIS is the most popular type of switchgear and is applied in areas where space is not a limitation. Compared with the GIS, the biggest advantage of AIS is its lower environmental impact.

BUSBARS

Busbars are the type of electrical junction where all the outgoing and incoming electrical currents meet e.g. in a converter. The busbar system also contains the circuit breaker and the isolator. In case of a fault, the circuit breaker is turned off and the faulty section of the busbar is disconnected from the circuit. DC busbars are typically constructed in pairs because of the two poles, however this is only true for DC bipole configuration, whereas AC has 3 phases.

FILTERS

Active power filters are power electronic components used to improve the efficiency of electrical energy use and its quality. The filter is connected in parallel with nonlinear loads and injects into the grid a harmonic current that is equal to but in opposite phase with the harmonic current produced by the nonlinear loads, hence making the total harmonic current approach zero and efficiently eliminating the effects of harmonics.

An active power filter consists of an incoming line contactor, IGBT inverter, filter, control and protection. An active power filter control system identifies the current on the load side, the system voltage at the connection point in real time, it determines the current required for harmonic compensation, and controls the three-phase IGBT inverters to give current tracking and compensation orders to damp harmonics on the load side. Apart from this, the filter is also responsible for protection against AC undervoltage/overvoltage, DC undervoltage/overvoltage, output overcurrent, overheating of the inverter and short circuit of the inverter. The main functions of an active power filter are compensation of reactive power for loads, increasing the power factor and energy saving, improvement the power quality of the distribution network, reduction of feeder losses and improvement of the efficiency of the distribution network.

CHOPPERS

Choppers are static power electronics device which convert fixed DC voltage/power to variable DC voltage or power. Simply, a chopper is an electronic switch that is being used interrupt one signal under the control of another signal. Depending on the voltage output, choppers can be divided as follows:

- Step Up chopper (boost converter), increase voltage.
- Step Down Chopper (Buck converter), decrease voltage.
- Step Up/Down Chopper (Buck-boost converter), increase or decrease voltage depends on duty ratio[31].

GROUNDING

System grounding is the connection of earth ground to the neutral points of current carrying conductors like the neutral point of a circuit, rotating machinery, a transformer, or a system, either solidly or with a current-limiting device. Grounded system has at least one conductor or point that is purposely grounded, or solidly either through an impedance. The objective of system grounding is the intentional connection of a phase or neutral conductor to earth, this is in order to control the voltage to earth, or ground**,** within predictable constraints. It also provides for a flow of current that will allow detection of an undesirable connection between system conductors and ground.

PHASE SHIFTERS

In a grid that has a problem with unwanted power flows from surrounding networks phase shifters are used. This is especially the case in grids that have hard-to-control feed-in from renewable power plants, in particular OWFs. Thanks to the change of the effective phase displacement between the input voltage and the output voltage of a transmission line, phase shifters block, enforce and even revert power flow and reduce or eliminate loop flows. Phase shifters can restore the balance of line loading between parallel lines or network sections. Grid operators use this ability to increase the transmission capacity of the network while minimizing expensive grid expansions.

[31] Duty cycle is the ratio of ON time to total time. It can be changed between 0 and 1.

TERTIARY COMPONENTS

Tertiary components are everything needed to support the other structures. In the case of offshore grids the main components of this are platforms, or potential artificial islands.

PLATFORMS

Platforms are built as supporting structures for VSC converters and other devices within a substation e.g. transformers. Their cost is very significant in offshore projects and scales up linearly with the size, therefore alternative solutions like artificial islands are being investigated.

ARTIFICIAL ISLANDS

An artificial island is used in the same way as a platform but could also be used to support power to X (P2X) facilities. Artificial islands have not been constructed in the North Seas but are explored within the PROMOTioN grid concepts. Current analysis suggests that building an artificial island is cheaper than building platforms of equivalent capacity, however without having demonstrated it, this is uncertain.

III. APPENDIX – ASSUMPTIONS AND BOUNDARIES OF ANALYSIS

This chapter sets out the assumptions and boundaries of the technical and non-technical analysis which informed the PROMOTioN project recommendations. Even though some of these criteria are closely intertwined (e.g. operational standards have to be ensured by a solid regulation coming from the European or national authorities, CBCA affects investment decisions, etc.), the structure of the chapter deliberately divides assumptions into specific issue-related blocks for ease of reference. Technical matters are addressed first, followed by legal, regulatory and financial assumptions. The final section in this appendix summarises topics which are out of scope.

TECHNICAL ASSUMPTIONS AND BOUNDARIES

This section describes the technical assumptions made during the development of this Deployment Plan. These have been categorised under four headings (Figure 16).

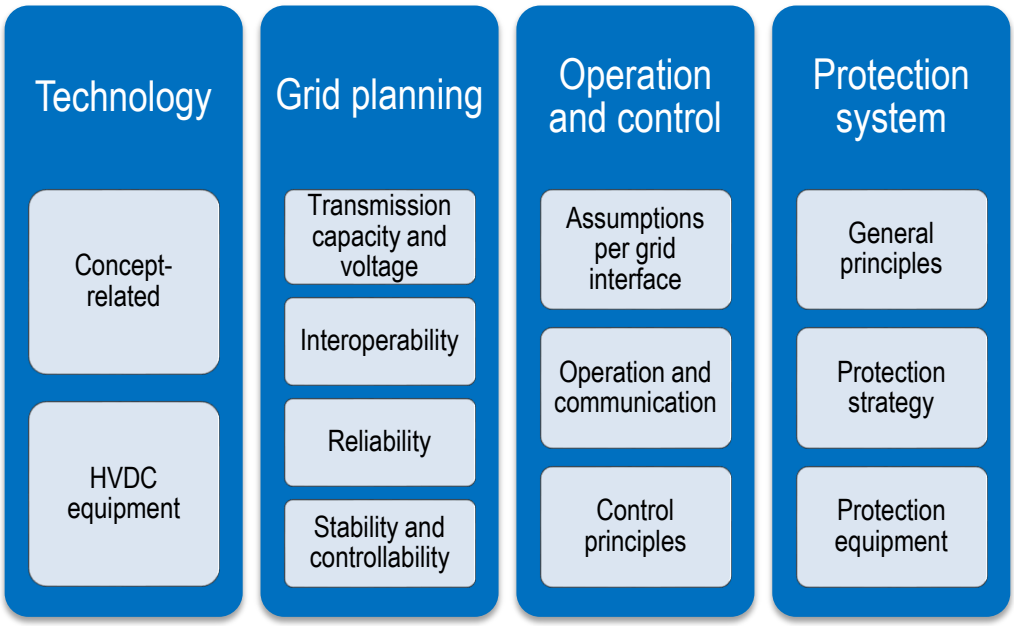


Figure 16 - Technical categories

- Technology assumptions specify the technology used for a specific purpose, including its performance and rating.
- Grid planning and operation & control assumptions are formulated as a list of requirements that an offshore grid has to fulfil. An exact specification of these requirements has been provided by different WPs within PROMOTioN.
- Protection system assumptions are split into the general requirements which have to be fulfilled and specific assumptions regarding protection strategy and required equipment.

TECHNOLOGY

This section presents the assumptions which were made regarding the specific technologies, components and HVDC equipment used in each of the PROMOTioN grid concepts. These assumptions do not describe specific capabilities of the technologies but rather provide information on which technology or equipment was used for the certain concept, or which were left out of scope in the project.

ALL CONCEPTS

Cables

- Overhead lines are out of scope for the PROMOTioN project; only underwater cables are considered.
- 525 kV cables are applied in the North Seas area, except in the English Channel and Irish Sea where 320 kV cables are applied.
- OWFs are connected to its hub through 66 kV AC cables if the distance is less than 50 km. If the distance is between 50 and 100 km, OWFs are connected to its hub with 150 kV AC cables. OWFs that are over 100 km away from its hub would have to be, in theory, connected through DC cables. However, WP2 advised against connecting a DC cable directly to the busbar of an AC/DC converter and as such this configuration is not considered in PROMOTioN.

Monopolar or bipolar

- All grids are assumed to be connected bipole. For radial connections, monopoles are allowed.
- A true bipole is used, as opposed to a rigid bipole, as true earthing is prohibited in some countries and faces environmental objections in others.

Converters

- Line-commutated converter (LCC) technology is out of scope of the PROMOTioN project. The focus is on VSC converters and DRU technology.
- The potential of DRUs is unclear in meshed systems, so it is assumed that DRU technology can be used only for radial connections. As such, DRUs are not taken into account quantitatively in the CBA. However, DRUs may offer cost savings due to reduced size and weight and could therefore be an interesting future option. DRU technology should be available in the near future.
- HVAC branches might be used in parallel with particular HVDC branches but operating at lower voltages, primarily for the purpose of providing auxiliary power. They are however not accounted in the cost calculation of the CBA.

Transformers

- DC transformers (DC to DC converters) are not studied within the PROMOTioN project. However, WP2 noted that these may be needed for the purpose of power flow control in the meshed grid, even if an equal voltage across the grid is assumed. A financial margin is therefore applied to account for potentially required investments.
- An AC transformer offshore is only considered for AC cables over 50 km (see 'Cables' above). AC transformers are also required onshore.

Platforms

- Platforms are of jacket type.
- The size of the platforms is directly related to the capacity of connected wind generation but also to the number of interconnector cables connected to the given hub.

- The maximum size of a platform is 2000 MW, before extensions for DCCBs and additional DC cable connections.
- A separate platform is used for the OWF substation that has an AC transformer of 150/66 kV where needed.

BUSINESS-AS-USUAL

In the Business-as-Usual concept, the technologies are the same as listed for all concepts. One important consideration is that as all the connections are radial thus monopole configuration is preferred. This also entails the use of AC circuit breakers onshore as opposed to DCCBs.

NATIONAL DISTRIBUTED

Cables

- Two or more offshore hubs may be connected using DC cables, creating hybrid assets; both a wind farm connection and interconnection.

EUROPEAN CENTRALISED

Cables

- As the connections are mainly radial, monopole configurations are dominant. Bipoles are considered for connection between islands.
- Islands are interconnected through DC cables.
- Hybrid assets are considered, used both for wind farm connections and interconnection.

Islands

- Islands are considered only in this concept.
- Maximum allowed size of the hub, as described in Deliverable 12.1, ranges from 4 GW to potentially 35 GW.
- Hubs are of AC type.

EUROPEAN DISTRIBUTED

Cables

- Hybrid assets are considered, used both for wind farm connections and interconnection.
- Two or more offshore hubs may be connected using DC cables.

HVDC EQUIPMENT ASSUMPTIONS

The assumptions on the main characteristics and performance of the specific HVDC equipment such as cables, converters, transformers, platforms, GIS, busbars and connection type are given in this subsection. It is assumed that all required HVAC equipment is readily available to be used in the MOG, as it is a long-used technology. A detailed description of all HVDC submodules and their ratings was given in Deliverable 2.1 and is not presented here. For each technology, specific characteristics (such as TRL) are described.

PRIMARY COMPONENTS

CABLES

Characteristic	Options	Comments
TRL	• 66 kV (AC) • 150 kV (AC) • 320 kV (DC) • 500 kV (DC)	• 9 • 9 • 9 • 6, however TRL is assumed to be high enough to be used in the near future.
Voltage	• 66kV • 150 kV • 320 kV • 525 kV	• OWF (inter array): 66 kV • OWF to hub (< 50 km): 66 kV • OWF to hub (50-100 km): 150 kV • Hub to shore/ hub to hub (Irish Sea, English Channel): 320 kV • Hub to shore/hub to hub (North Sea): 525 kV
Hybrid or conventional	• Conventional • Hybrid, (can be used with DRU)	• Conventional cables consist of two DC cables separately and one umbilical separately. • Hybrid cables are designed to overcome the limitations of unidirectional converters. Hybrid cables consist of two DC cores and AC umbilical combined in one cable.
Insulation	• XLPE • Paper-oil	• XLPE are the preferred choice, as they are cheaper, lighter and easier to handle than mass-impregnated cables. (Deliverable 2.1) • Paper oil no longer allowed offshore in some sectors.
Power capacity (per circuit)	• 700 MW • 900 MW • 1.0 GW • 1.2 GW • 1.4 GW • 1.6 GW • 2.0 GW	• Power capacity dependent on the capacity of connected OWFs and voltage level.
Umbilical cable		• In hybrid cables needed to provide start-up voltage
Underground or submarine	• Submarine • Underground	• Submarine cables are used offshore. • Underground cables are used onshore.
Losses	• 0.002 %/km	• Cable losses are strictly connected with cable resistance per km. In the used model, resistance values varies depending on rated DC current and their values are between 0.0087-0.022 Ohm/km.
Failure rate	• Pole-to-pole • Pole-to-ground • Physical disconnection of the cable	• Pole-to-pole: Never happens during the life of the HVDC system. • Pole-to-ground: Less than once per 30 years. • Physical disconnection: Less than once per 30 years.

Monopolar or bipolar

So far in offshore applications, the benefits of symmetrical monopoles (with regard to compactness and associated cost) have exceeded the additional benefits with regard to redundancy gained in asymmetrical/bipolar configurations. However, within the PROMOTioN project not symmetrical monopoles but bipoles are chosen. This is a result of the fact that bipole systems provide an inseparable redundancy allowing for continued but reduced transmission capability to be utilised by switching to monopole operation under single pole cable or converter fault conditions or maintenance outages.

Characteristic	Options	Comments

Monopolar or bipolar	• Asymmetrical monopole • Symmetrical monopole • Bipole	• Asymmetrical – one cable and return, one converter: no redundancy. • Symmetrical – two cables, one converter: no redundancy. Double the power transfer of asymmetrical monopole with same rated pole voltage and rated current. • Bipole – two cables and return, two converters (of half power of symmetrical), same power as symmetrical, higher redundancy due to monopole operation capabilities.
Different configurations in one system	• Yes • No	• It is technically feasible that different converter configurations could be adopted within the same multi-terminal HVDC system with asymmetric or symmetrical monopole configured branches tapping into bipole configured branches. However, such configurations would impose limitations on the design of converters to ensure compatibility. HB converters can then not be used. As such, the PROMOTioN project does not assume such configurations to be present.
Pole rebalancing equipment	• DC surge arresters	• Especially important in symmetrical monopoles since a pole-to-ground fault will result in a 0-2pu voltage at the healthy pole. • DC surge arresters can be located at the substation output (on the DC side) or at the top of the cascaded sub-modules protecting the corresponding pole from the overvoltage from DC lines.
Behaviour in case of faults	• Blocking + ACCB trip • DCCB trip • Fault current control	• In case of a symmetrical monopole, pole-to-ground fault results in temporary double voltage in the healthy line, therefore short time withstand voltage shall be considered. • Within the cable system, if the positive and negative polarity cables are bundled, then pole-to-pole faults shall be considered, whereas if cables are separated, then only pole-to-ground faults shall be considered.
Earthing arrangement		• Symmetric monopole is commonly ground with a high impedance start point reactor on the AC side of the converter. • Bipolar systems are solidly grounded on the DC side at the midpoint between the converters.

CONVERTERS

Voltage Source Converters

VSCs may consist of HB or FB. They can provide fast dynamic support to adjacent AC grids. The DC grid can hence support the overall system stability by providing reactive power to adjacent AC grids and thus mitigate the impact of a nearby AC fault without influencing the DC voltage. VSC-HVDC gives a reference available to OWF to be synchronised with. It allows the start-up of the offshore grid and to control the offshore AC voltage by itself, by proper coordination with the OWF. Besides, VSC technology allows fast redirection of power flows and can provide fast fault current (FFC) during offshore faults, as opposed to DRUs. Fault current is the current that flows during a fault condition, which will not necessarily be a short-circuit condition. A short-circuit current will flow if there is short-circuit in the system, and it will represent the highest possible fault current that a system can experience. Thus, a fault current can be less than the short-circuit current, and a short-circuit current will represent the highest fault current in the system

Characteristic	Options	Comments
TRL	• HB • FB	• 8 or 9 depending on voltage level. • 5 or 6 depending on voltage level. Assumed to be available in the near future.

Type	• HB • FB	• HB-MMCs are not capable of over-modulation or blocking current during DC faults. • HB have limited capabilities compared to FB as far as DC faults are concerned. • Blocking of a FB MMC results in an interruption of the DC fault current. • FB may reduce the need for some DCCBs in the system (partially fault clearing strategy). However, this is not considered in the project. • Due to the two additional IGBTs, FB submodules can also generate negative voltages. • When a protection strategy is chosen that uses mechanical DCCBs, the VSCs must be of FB type.
Voltage (AC and DC)	• 320 kV • 525 kV	• 320 kV considered for Irish Sea and English Channel. • 525 kV considered in the remaining North Seas.
Power	320 kV: • 700 MW • 900 MW • 1.2 GW 525 kV: • 1.0 GW • 1.4 GW • 1.6 GW • 2.0 GW	• Whether certain power ratings are allowed in certain areas in the North Seas is also dependent on the maximum allowable loss of infeed.
Availability		• Whether higher rating converters are assumed to become available later.
Losses	• 0.8 %	
Mean time to failure	• 6257 hours	
Mean time to repair	• 6 hours	

DRU

Within PROMOTioN, DRUs can be used only for OWFs connected radially (point-to-point) to the shores. This is a result of the fact that the DRU is technically a rectifier and not a full converter and thus can convert only form AC to DC. Therefore, the use of DRUs is not taken into account quantitatively in the CBA, but its use could be a future option.

Criteria	Options	Comments
TRL		• 5
Type of connection	• Radial OWF to shore • OWF to single hub • OWF feeding into an interconnector (T-connected)	• Depending whether or not DRUs can be used in other than OWF-shore connections, the overall cost of the network will change significantly.
Platforms	• Few units on one platform • Large number of small platforms	• The volume of the platform structures is reduced by 20 %. • The weight of platforms is reduced by 45 %. • Two DRU modules installed per platform. • Typical 1200 MW OWF connection consists of three offshore platforms.
Type of start-up voltage source to be accompanied with	• Umbilical cable • Diesel generator • Battery	
Voltage	• Rated AC Offshore Grid Voltage (L-L): 66 kV	• Each OWF will produce power at low voltage AC (66kV).

	• Rated DC Voltage (U_{DC}) 320 kV.	• DRU modules will be connected in series to provide the +/-320 kV DC voltage.
Power rating	• Module rated power 200 MW	• The DRU system is build up by connecting six DRU modules in series on the DC side. • Each DRU module operates on a 12-pulse configuration.
Modularity	• Compact structure	• The DRU solution eliminates the need for collector grid AC offshore substations as the collector cables are directly connected to the DRU platforms
Grid support capabilities	• Frequency support • Power oscillation damping • Primary Frequency response • Fast frequency response	• DRUs always stay connected independent of offshore ROCOF. VSCs, may trip
Control implications		• Voltage and power flow control requirements are transferred to OWF and onshore converters.
Size	• Installation space reduced by 80%.	• DRU, the transformer, the smoothing reactor, and the rectifier are combined in one tank.
Losses	• 20 % less than for VSC	

TRANSFORMERS

Criteria	Options	Comments
TRL	• 150 kV • 220 kV • 420 kV	• 9 • 9 • 9
Voltage	• 150/66 kV • 220/150 kV • 420/150 kV	• OWF transformers are assumed to be of 66 kV to 150 kV.
Power	• 250 MVA • 300 MVA	• For voltages 150/66 kV • For voltages 220/150 kV
Platform	• Yes	• Every transformer will be installed on separate platform.

SECONDARY COMPONENTS

AC/DC BUSBAR / HUBS CONFIGURATION

Criteria	Options	Comments
DC busbars decoupling possibility	• Decoupled with a few DCCBs • Single bar with many DCCBs	• Multiple onshore busbars reduce the need of DCCBs • Considering each onshore bus to be composed of a single bar would be unrealistic and it will substantially increase the number of DCCBs required.
Layout for concept	• Double busbar – double breaker • Breaker and a half • Decoupled • Single • Ring	• Double busbar – double breaker is used for single node AC hub sub-concept. • Breaker and a half applied for the single node AC hub concept. • The single node AC hub sub-concept allows the interconnections of HVDC lines with different voltage levels and different DC link configurations. • Each of the three substations in ring node AC hub should be organised to achieve high reliability, thus the same substation layouts suggested for the single

		node could be applied.
AC hub concepts and busbar arrangement	• Single node AC hub • Backup node AC hub • Ring AC hub	• A major disadvantage of AC single node topology is that a substation shutdown would completely block the power flow through the hub. • The objective of the back-up substation is to keep power flowing through the hub in the event of a major failure in the main substation. • In the ring case, a substation failure would not lead to a complete shutdown of the hub, since the two healthy substations can continue to operate.
Hybrid AC/DC hub		• Essentially the same AC hub but with increased frequency to reduce the space of the hub. • More complicated to control. • The frequency can be selected differently.
Mean time to failure	• 870000 hours	
Mean time to repair	• 6 hours	

TERITIARY COMPONENTS

PLATFORMS/ ISLANDS

Criteria	Options	Comments
Capacity of the cables	• Higher meshing means bigger or even additional platforms	• If more than one cable connects an OWF to another node of the Meshed Offshore Grid or to the mainland, additional offshore platform space is necessary to accommodate the DC bus.
Capacity of island (depending on the depth)	• >4GW and potentially up to around 35 GW	• It may be assumed that island capacity can be fitted according to the demand.
Average capacity	• Island 16 GW • Platform 2 GW	• Platform cost very high, scales linearly with size.
Application	• Supporting structure for primary and secondary equipment	• Islands can store more components due to bigger area and no limitations of mass of the components.
Platform	• Jacket type	• Platforms are required as a supporting structure for VSC. • VSC have high mass and volume, big area requirements. • Platforms very close to the park (minimizing the length of the 66kV cables).
Number units	• 6 islands	• A maximum of six potential artificial islands are used in the development of the topologies for the centralised hub concept. • It is assumed that 1 island can replace 8 platforms (Deliverable 12.2)
Area top	• Island 128 000 m^2 • Platform 10 000 m^2	• Sand island will likely attract species that will benefit from the reclaimed land for resting, feeding and breeding.
Area bottom	• Island 325 431 m^2 • Platform 10 000 m^2	• Island may change the direction of sea currents.
Circumference top	• Island 1 268 m • Platform 3 200 m	• One island creates a new artificial shoreline.
Circumference bottom	• Island 2 022 m • Platform 3 200 m	• The island will be a solid structure, while the platform allows water to flow through.
Water depth limitations	• Island < 40m	• Island construction has high influence on a

	• Platform < 45 m	seabed.
Cost	• Platform scales linearly with size • Island constant cost	• Implementation of island can reduce OPEX by 50 %.
Construction time	• Island 8 years • Platform 3 years	• Island-based foundations reduce investment costs and can enable larger scale interconnection hubs at lower costs compared to platform-based hubs, this compensates longer construction time.

GRID PLANNING

The planning criteria aim to recommend the most economical topology which does not violate the operational and technical requirements. Furthermore, the planning principles have first to ensure that the transmission power system can accommodate the load and the generation under normal conditions while satisfying operational limits and being stable. This section proposes basic planning criteria assumptions which allow for the adequate comparison of different concepts and do not discriminate possible options. Majority of these assumptions are formulated as a list of requirements to be fulfilled by the grid.

Note that a prerequisite for offshore grid planning is the forecast of the development of offshore wind energy, as well as the forecast of the evolution of load and generation in North Seas countries (and neighbouring countries). These inputs were formulated as scenarios and are described earlier in Deliverable 12.2.

Currently, no specific planning criteria exist for Meshed Offshore Grids. WP1 has put a first effort to structure and draft what such criteria could be, based on the existing criteria for onshore grids. The aspects to consider include:

- Transmission capacity requirements and voltage levels
- Interoperability
- Reliability
- Stability and Controllability

The following functional system requirements are assumed to be fulfilled by the offshore grid in order to be considered technically feasible. Several interactions between planning, technology and operational choices, and the financial side are expected for grid planning.

RELIABILITY

The reliability of an offshore grid is its ability to operate without endangering offshore and onshore grid stability in normal operation as well as in disturbed operation. The reliability criteria of the offshore grid are defined follows:

- A single contingency cannot lead to an unacceptable disturbance in the onshore grid, like a load shedding.
- Following a single contingency, the loss of power infeed for a specific zone must be below the reference incident of that zone (Table 6), and the global loss of power infeed in all zones must be below the maximum value of all the reference incidents in the various zones (i.e. 3000 MW in this case).

Table 6 - Reference incidents in Europe

SYNCHRONOUS ZONE	REFERENCE INCIDENT
Continental Europe	3,000 MW
Nordic	1,400 MW

Great Britain	1,850 MW
Ireland and Northern Ireland	Up to 700 MW

- Offshore grids must be planned to evacuate the offshore power generation and to exchange power between countries at an economic cost taking into account the future evolution of generation and load, fault clearance strategies[32], etc. Since the offshore peak load (e.g. offshore oil/gas platforms) is expected to be much lower than the installed offshore generating capacity, the peak load is not a critical condition. On the contrary, the peak generation is a critical condition.
- Peak generation is analysed when all offshore wind generators produce at their nominal rating.
- A coordinated planning among the involved TSOs could be required and some information about the converter controls will have to be exchanged.
- A MOG will combine both evacuation trading within countries and evacuation of offshore wind energy. Thus, the responsibility regarding the ownership, maintenance, and construction of a MOG should be clearly defined and assigned.
- Following a single (N-1) contingency:
    - The system must stay electrically stable.
    - No uncontrolled cascading outage is allowed (but the disconnection of an OWF radially connected, or an action of an automatic Remedial Action Scheme is allowed).
    - Electrical variables (e.g. power flows, voltages) must be within emergency operating limits just after the contingency, once the automatic voltage droops of converter controller have stabilised the system, and they should go back to normal (continuous) operating limits after system adjustments.

For the PROMOTioN project it is assumed of the same value as the maximum allowed loss of power infeed. This is to prevent current local constraints to be limiting in the future.

INTEROPERABILITY

Interoperability of the MOG characterises the possibility to integrate different types of devices from different vendors into the MOG without compromising the expected behaviour of the system. Interoperability states that:

- Operation of new technologies together with existing and installed technologies is possible for the grid operators.
- It is possible to use an independent supervisor or master control to coordinate actions and orders between the different equipment of the MOG.
- Common communication interfaces must be defined for each type of devices.
- In order to achieve interoperability on subsystems, specific technical requirements on interfaces are needed:
    - Electro-technical requirements of converters and other HVDC equipment. Each HVDC converter unit of an HVDC system must be equipped with an automatic controller capable of receiving set points and commands from the relevant system operator and from the relevant

[32] Partially selective fault clearing strategies rely on the proper placement of DCCBs or DC/DC converters to split the grid into separate zones. When the topology of the grid changes due to the addition of new DC lines and/or converter stations, the original grid splitting solution might no longer be valid.

onshore TSO. This automatic controller must operate the HVDC converter units of the HVDC system in a coordinated way.

  - The definition of interfaces should be designed such that it will allow for easy forward and backward interoperability.

- Subsystems (e.g. the protection system) should be interoperable between vendors and technologies during the lifetime of the equipment:
  - Equipment should offer stepwise (temporal independent) interoperability (upward compatibility).
  - Manufacturers should be able to adapt their equipment (when necessary due to interoperability issues) during their lifetime. For this purpose, producers shall commit to communicate some minimal set of relevant data (signals, measurement) for a common solving of issues.

Furthermore, interoperability troubles may not only occur under faults, but under dynamic events such as load changes as well. This is why a very detailed specification of the converter behaviour is required. Moreover, dynamic controls such as droop controls have to be identified as they will require further specification. A more precise approach could be achieved by standardising the upper level controls, such that only the lower level controls are vendor specific.

TRANSMISSSION CAPACITY AND VOLTAGE

Offshore grids are planned with the main goal to evacuate the offshore power generation and secondary - to exchange power between countries at an economic cost taking into account the future evolution of generation and load. The offshore grid needs sufficient transmission capacity for various parts:

  - From OWFs to the terminals of the offshore grid
  - Between the terminals of the offshore grid
  - From OWFs or terminals of the offshore grid to the onshore grid.

- The limits on the maximum power injection onshore are taken into account while planning the offshore grid. Note: while generating topologies within WP12, the onshore grid reinforcement was regarded as out of scope, however the landing points used for topologies are substations which exist in reality. For some of them, the infeed capacity was increased to accommodate power infeed.
- The power transmission system must ensure the power flows given by the economic dispatch (or another reliable dispatch) of generating units, without load shedding, with power flows through transmission elements within a normal (continuous) rating.
- Under normal conditions voltages at all nodes must be between 0.95 p.u. and 1.05 p.u.
- If higher values of interconnection capacity are economically viable, independent of wind situation, increased interconnection capacity can be considered.
- The capacity of a circuit of an interconnector between synchronous area A and synchronous area B (with A≠B) is limited to the minimum of the maximum loss of active power injection allowed in area A and the maximum loss of active power injection allowed in area B. This means that the interconnector capacity cannot be bigger than the maximum loss of active power injection in one of the connected areas.
- The part of the infrastructure not necessary for the evacuation of offshore wind energy can support the operation of the connected onshore system by providing auxiliary services such as reserves or reactive power or serving offshore loads.
- DC/DC converters are out of the scope of the PROMOTioN project. Therefore a single voltage level has to be selected for the multi-terminal meshed DC offshore grid. The voltage of the grid contains two levels

– 320kV and 525kV, where the former is used mainly for point-to-point connections with the transfer of power up to 1GW and the latter is used for the transfer of power up to 3GW, as is shown in Figure 17. In the PROMOTioN project, this is translated to a voltage of 320 kV for a power range of 0.7 – 1.2 GW and 525 kV for a range of 1.0 – 2.0 GW. In the meshed concepts a single voltage of 320 kV is adopted for the Irish Sea and the English Channel and 525 kV for the remaining North Seas area. In the Business-as-Usual and European Centralised (with AC super-node) concepts there is, practically, no need for a single voltage level. However, for the purpose of fair comparison, the same voltages are assumed for the respective North Seas areas in these concepts.

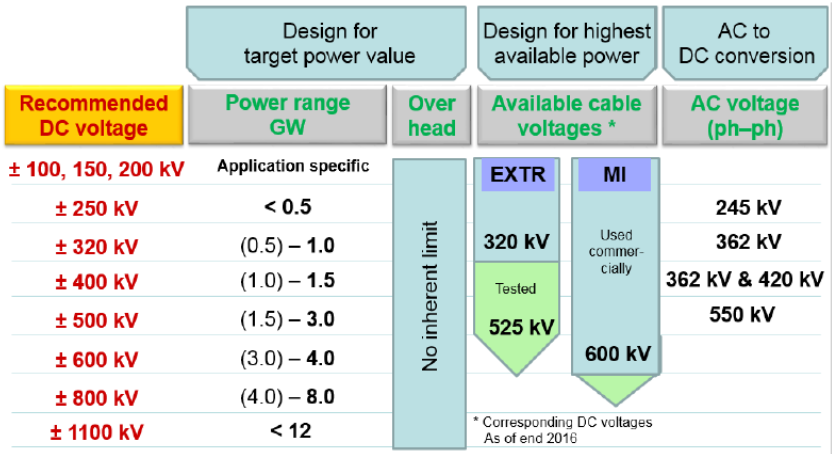


Figure 17 - Recommended DC voltage level and possible DC power transfer range

OPERATION AND CONTROL

This section focus on the assumptions which need to be undertaken towards the operation of the meshed grid, in order to make it technically feasible. It is not sufficient to have only the elements of the grid; these elements must be able to cooperate to form a system that is fully capable to fulfil the operational requirements, hence to be controllable. The main controllable elements in the DC network are converters; their fundamental function is adjusting the direction of the power flow. Although the active power flows through each converter depend strongly on the results of the market-clearing for each offshore wind generator and for cross-border flows, there might be several ways to set the active power flows in line with the market-clearing (e.g. in case several converters connect an offshore grid to a country).

Nowadays, the operational criteria for the onshore and offshore grid are regulated by National grid codes and European network codes. Taking into account the fact that the objective of PROMOTioN is regarding HVDC MOGs, it is anticipated that the EU network codes will apply. This is a result of the fact that national codes are predominantly designed for AC networks. For the radial connections, existing codes can be applied directly, since no barriers are foreseen for the concepts where no meshing is envisaged. Codes often describe principles and frameworks purposely left open for the national TSOs to fill in. Meshed DC grids and DC collection grids are out of the scope of this network code, therefore a significant part of the following assumptions focuses on the barriers present due to the gaps in the existing Network Codes. Despite the fact that certain requirements are fixed in the Network Codes already, the Network Recommendations have been given by WP1 (Deliverable 1.5, Deliverable 1.6, Deliverable 1.7) and WP2.

STRUCTURE OF OPERATIONAL CRITERIA AND ASSUMPTIONS

Following the structure proposed by WP1, the operational requirements can be easily split according to the interfaces where they apply (Figure 18):

- Meshed Offshore Grid – *Onshore AC system;* constraints the tolerable variations of the quality and power output. The ENTSO-E Network Code on HVDC Connections was taken as a starting point, which dictates requirements of the MOG.
- Meshed Offshore Grid – *Offshore generation;* puts requirements on the power output of offshore AC generation. The ENTSO-E code on Requirements for Generators is used as a starting point.
- Meshed Offshore Grid – *Offshore consumption;* present possible connections to offshore consumer. Offshore consumption is out of the scope of PROMOTiON project.
- Meshed Offshore Grid – *Operation;* depicts the requirements for steady state operation of the DC grid.
- Meshed Offshore Grid – *Control;* entails the requirements on information exchange and control procedures.

The relevance for the operational criteria is then applied to each concept, where some criteria may or may not be applied according to the concept description.

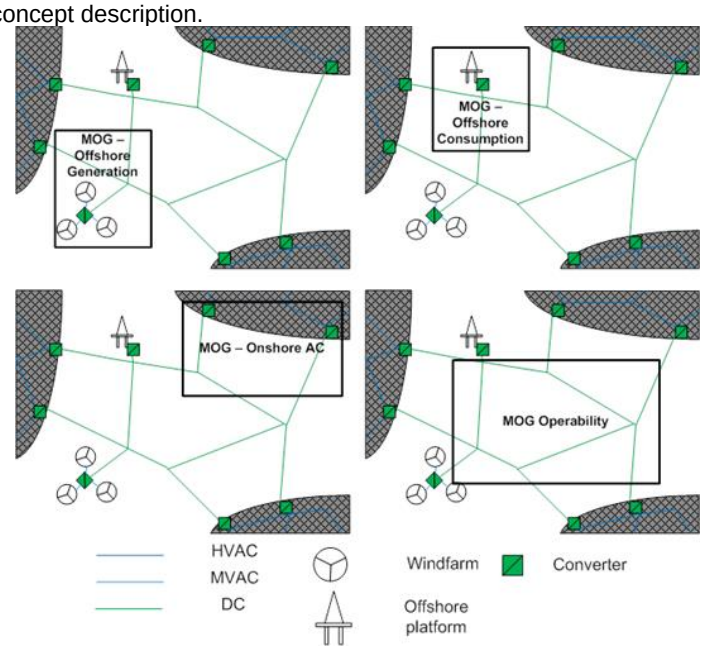


Figure 18 - Grid Operation Interfaces

Deliverable 1.7 contains a specified formulation of the requirements as proposed by WP1. The list of recommendations for each criterion, which is not defined in the existing Network code, is given. The requirements for each interface were analysed and, where possible, quantified based on the existing grid codes applicable to HVDC grids: ENTSO-E HVDC grid code (NC HVDC), ENTSO-E code on Requirements for Generators (NC RfG). Since some of the requirements do not exist yet or are not quantifiable for MOG, their definition was based on scientific studies or was given in a form of general recommendations. The recommendations and solutions which were found are assumed to be valid for further analysis.

MESHED OFFSHORE GRID – ONSHORE AC SYSTEM

The assumption is that the considered topologies satisfy the following requirements that base on grid code. An exact formulation can be found in Deliverable 1.7

ACTIVE POWER CONTROL AND FREQUENCY SUPPORT REQUIREMENTS

- **Frequency ranges** - an HVDC converter must remain operable within the certain frequency ranges and time periods (Table 7).

Table 7 - Complete table of frequency ranges and time period of operation for an HVDC system

FREQUENCY RANGE	TIME PERIOD OF OPERATION
47.0 Hz – 47.5 Hz	60 seconds
47.5 Hz – 48.5 Hz	To be specified by the relevant onshore TSO but longer than 30 minutes
48.5 Hz – 49.0 Hz	To be specified by the relevant onshore TSO but longer than 90 minutes
49.0 Hz – 51.0 Hz	Unlimited
51.0 Hz – 51.5 Hz	To be specified by the relevant onshore TSO but longer than 90 minutes
51.5 Hz – 52.0 Hz	To be specified by the relevant onshore TSO but longer than 15 minutes

- **Rate of change of frequency capability** - when the network frequency changes with a rate of ± 2.5 Hz/s the HVDC system must be suitable to stay connected to the network and operate.
- **Frequency sensitive mode** - AC/DC converters in the HVDC system have to be equipped with a separate control mode to modulate the active power output of the HVDC converter station according to the frequencies at all connection points of the HVDC system to keep stable system frequencies and/or contribute to the frequency control of the AC system.
- **Active power controllability, Control range and Ramping rate** – AC/DC converters must have the ability to control the active power up to the maximum transmission capacity in each direction. Grid code of different countries demand different levels of ramping rate [6].
    - Germany, with an upper ramp rate limit of 10% of grid connection capacity per minute
    - Ireland, with a ramp rate of 1 – 30 MW/min
    - Nordic grid code, with an upper ramp rate limit of 600MW/hour
    - Denmark, with a ramp rate 10 – 100% of rated power per minute.
- **Synthetic inertia** – The HVDC system, in collaboration with the onshore TSOs, must determine the capability of providing synthetic inertia support in response to frequency variation in one or more AC networks, activated in low and/or high frequency regimes by rapidly adapting the active power injected to or withdrawn from the AC networks in order to limit the rate of change of frequency (ROCOF).
- **Maximum loss of active power** - loss of active power injection in a synchronous area should be limited to a value determined by the relevant TSO for their respective load frequency area control. Within PROMOTioN it is considered these values are equal to those given in Table 6.

REACTIVE POWER CONTROL AND VOLTAGE SUPPORT REQUIREMENTS

- **Voltage ranges** - the HVDC system should be able to operate at an AC voltage at the converter stations varying bye 1 p.u. reference value of voltage. An HVDC system must be capable of automatic disconnection at connection point voltages specified by the relevant onshore TSO.
- **Reactive power capability** - the system operator, in collaboration with the relevant TSO, should determine the reactive power capability requirements at the connection points, in the context of varying profile.
    - **Reactive power exchanged with the AC network** - the HVDC system owner should guarantee that the reactive power of its HVDC converter station traded with the network at the connection point is limited to

values specified by the TSO and system operator. The reactive power change caused by the reactive power control mode operation of the HVDC converter station, cannot result in a voltage step exceeding the allowed value at the AC connection point.

- **Priority to active power or reactive power contributions** - TSO should decide if reactive power contribution or active power contribution has priority during low or high voltage operation and during faults for which fault ride-through (FRT) capability is required.
- **Power quality** – the onshore TSO has to define maximum level of distortion allowed from the HVDC installation at the point of common coupling.

FAULT RIDE-THROUGH CAPABILITY REQUIREMENTS

- **FRT capability** – the HVDC system should stay connected to the network and continue stable operation after the power system has recovered following fault clearance.
- **Short-circuit contribution during faults** – the HVDC system must provide fast fault current at a connection point in case of a symmetrical three phase fault. The HVDC system cannot contribute with fault current more than 1 p.u.
- **Post-fault recovery** - the HVDC system should provide active power where the magnitude and time profile should be specified by the relevant TSO.
- **Fast recovery from DC faults** - the HVDC system should isolate and clear the DC fault and fast recovery from transient faults within the HVDC system. This depends on the agreements and coordination on the protection schemes and settings.

CONTROL REQUIREMENTS

- **Energization and synchronization** - the converter should have the capability of limiting any voltage ranges to a steady – state level. The level determined should not exceed 5% of the pre – synchronization voltage.
- **Interaction between HVDC systems and other AC connected plants and equipment** - components installed in the HVDC converter station (filters, controllers etc.) are all in close vicinity thus they have to be designed in such a way that no negative interaction occurs between the components and between stations.
- **Power oscillation damping capability** - the HVDC system should contribute to the damping of power oscillations in the AC network. The control system of the HVDC should not reduce the damping.
- **Network characteristics** – the onshore TSO must make available and public the pre-fault and post-fault conditions for calculations of the minimum and maximum short circuit power at the connection points. The HVDC system must be capable of operating within the range of short circuit power and network characteristics specified by the onshore TSO.

PROTECTION DEVICES AND SETTINGS REQUIREMENTS

- **Priority ranking of protection and control** - the control scheme described by the HVDC system owner consists of different control functions that should be coordinated (settings of specific parameters) and agreed with by the relevant TSO. The priority must be from increasing to decreasing order of importance.
- **Changes to protection and control schemes and settings** - settings of the parameters should not be able to be changed from the HVDC converter station.

POWER SYSTEM RESTORATION REQUIREMENTS

- **Black start capability** - in an emergency situation, the relevant TSO can obtain a quote from the owner of the HVDC system in order to energise the busbar of the AC – substation to which another converter station is linked, within a certain timeframe.

INFORMATION EXCHANGE AND COORDINATION REQUIREMENTS

TSOs should specify how an HVDC system is suitable for modifying the transmitted active power infeed in case of disturbances into one or more AC networks to which it is connected. Several TSOs should participate and have solidarity agreements for supporting each other.

It was concluded by WP1 that most of the aspects defined in the grid codes can be applied directly for MOGs. This is the main assumption adopted for the further analysis. Nonetheless, there are requirements which are not defined. Some of these issues were addressed by WP1 and recommendations are given in Deliverable 1.7. For others it is assumed that the solution is in place by the time the coordinated planning of the actual grid will start.

MESHED OFFSHORE GRID – OFFSHORE GENERATION

The objective of this interface is that the offshore grid has to fulfil the requirements for OWFs and requirements for offshore HVDC terminals. Apart from that, the potential use of DRUs and grid meshing results in a few additional assumptions is presented later in this subsection.

ACTIVE POWER CONTROL AND FREQUENCY STABILITY REQUIREMENTS FOR OWFS

- **Maximum power point tracking** – the turbine generator installed has to be capable of performing a Maximum Power Point Tracking function.
- **Operational frequency range** - the OWFs have to be capable of staying connected in the network and operate within determined frequency ranges (Table 8)

Table 8 - Minimum time periods for the 50 Hz nominal system for which a PPM shall be capable of operating for different frequencies without disconnecting from the network.

FREQUENCY RANGE	TIME PERIOD FOR OPERATION
47.0 Hz – 47.5 Hz	20 seconds
47.5 Hz – 49.0 Hz	90 minutes
49.0 Hz – 51.0 Hz	Unlimited
51.0 Hz – 51.5 Hz	90 minutes
51.5 Hz – 52.0 Hz	15 minutes

- **Operational rate of change of frequency** - OWFs should stay connected to the network and operate at rates-of-change-of-frequency up to a determined value. OWFs should automatically disconnect at determined rates-of-change-of-frequencies. If the system frequency changes at a rate up to ± 2 Hz/s (measured at any point in time as an average of the rate of change of frequency for the previous 1 second [7]. ROCOF ranges specified in Figure 19 are applied with ROCOF of the fundamental frequency of the OWF AC voltage measured at interface between the OWF and OTS. ROCOF can be measured as a moving average over the last 10 periods. The frequency is provided as a setpoints to the OWF in case of Transmission state.

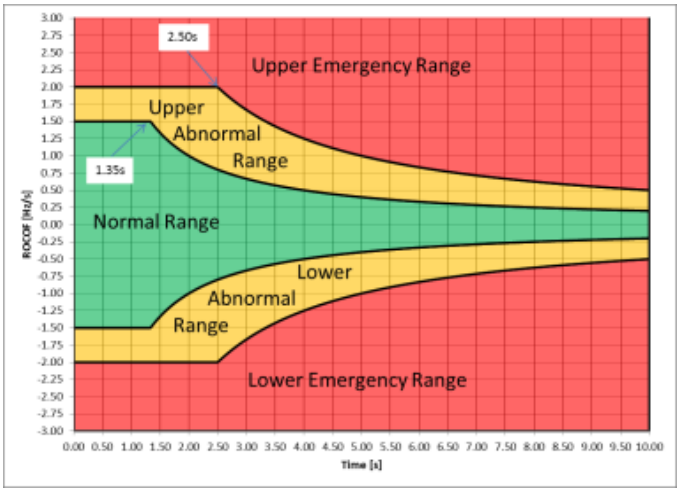


Figure 19 - ROCOF Ranges

- **Active power independency of frequency** - the OWF module should keep a constant output at its target active power value regardless of changes in frequency inside the range specified.
- **Active power control** - OWFs should adapt an active power set-point in line with instructions given to the OWF operator by the system operator (constrained by available power). Minimum and maximum limits on rates of change of active power output (ramping limits) in both increase and decrease of active power output for OWF will be specified.
- **Frequency response processing** - OWFs should receive an onshore frequency signal (measured at the onshore synchronous area connection point and sent by the onshore converter or master controller).
- **Frequency response activation** - OWFs should activate a power frequency response with an initial delay that is as short as possible. The frequency response will consider ambient conditions (mainly wind speed) at the time of response triggering and the operating conditions of the OWF. OWFs should provide active power frequency response for a specified duration.
- **Frequency response parameterization** - OWFs should provide active power frequency response based on a set of determined parameters which allow for the calculation of the active power as a function of the frequency.
- **Synthetic inertia** - OWFs may be required to provide synthetic inertia. The operating principle of control systems installed to provide synthetic inertia and the associated performance parameters will be determined by the relevant system operator.
- **DC voltage response** - OWFs may be required to contribute to DC voltage response to support the HVDC grid.

ROBUSTNESS AND CONTROL DURING SHORT – CIRCUIT FAULTS REQUIREMENTS FOR OWFS

- **Offshore AC fault ride through** - the OWF should stay connected to the network and continue to operate after the network has been disturbed.
- **Post – fault recovery** - after a disturbance with zero residual voltage at the grid connection point a restart of the generation plant with maximum 10% per minute of the maximum installed active power is allowed.

- **Fast fault current during offshore faults** - the OWFs should provide fault current at the connection point in case of symmetrical[33] or asymmetrical[34] faults. The amount of fault current that the OWF must inject depends on the size of the wind farm as well as the type of the fault.
- **DC fault ride through** - OWFs should collaborate with the DC grid control and protection systems in order to change its output during faults, provided that the DC fault can be detected by the OWF.
- **Onshore ac fault ride through** - OWFs should modify its output during onshore AC faults, provided that the onshore AC fault can be detected by the OWF.

VOLTAGE STABILITY REQUIREMENTS FOR OWFS

- **Operational voltage ranges** - OWFs should stay connected to the network and operate within the ranges of the network voltage at the connection point, when the voltage deviates from 1 p.u. for the determined time periods.
- **Reactive power control** - OWFs should meet determined reactive power control requirements.
- **Power oscillation damping** - OWFs should contribute to damping of power oscillations. The voltage and reactive power control characteristics of OWFs must not unfavourably affect the damping of power oscillations. OWFs should modulate its active power output as response to a signal for provision of damping via active power to the onshore AC grid.
- **Start–up** - OWFs should perform essential control actions, in collaboration with the offshore HVDC terminal, in order to start-up the offshore AC grid.
- **Auto–synchronous operation** - if there is no reference available to be synchronised with (e.g. VSC-HVDC or umbilical AC line), OWFs should perform auto-synchronous operation, where the OWF forms and controls AC grid voltage in its collector system. OWFs should be able switch between synchronous and auto-synchronous operation.
- **Power quality** - OWFs should guarantee that their connection to the network does not result in a level of distortion or fluctuation of the supply voltage on the network at the connection point.

OPERATIONAL RANGES REQUIREMENTS FOR OFFSHORE HVDC TERMINALS

- **Offshore AC link voltage range** – An offshore HVDC terminal should stay connected and operable at determined offshore AC voltage levels. Automatic disconnection will be allowed at determined offshore AC voltage levels.
- **Offshore AC link frequency range** - the HVDC converter must stay operable within the certain frequency ranges and time periods. Automatic disconnection will be allowed at determined frequency levels.
- **Offshore rate of change of frequency** – an offshore HVDC terminal should stay connected and operable if the network frequency changes at up to a specified rate.
- **Offshore active power exchange** – an offshore HVDC terminal should adapt the transmitted active power up to its maximum HVDC active power transmission capacity in each direction following an instruction and should adapt the ramping rate of active power variations within its technical capabilities in accordance with instructions sent by Offshore Grid Operator.

[33] Symmetrical faults- all the phases are short-circuited to each other and often to earth. This fault is balanced in the sense that the systems remain symmetrical, or it can be said that the lines displaced by an equal angle (i.e. 120° in three-phase line). It is the most severe type of fault involving the largest current, but it occurs rarely.
[34] Asymmetrical faults- engage only one or two phases. In unsymmetrical faults the three-phase lines become unbalanced. This type of faults occurs between line-to-ground or between lines. An unsymmetrical series fault is between phases or between phase-to-ground, whereas unsymmetrical shunt fault is unbalanced in the line impedances

OFFSHORE BEHAVIOUR DURING SHORT–CIRCUITS FAULTS REQUIREMENTS FOR OFFSHORE HVDC TERMINALS

- **Offshore AC fault ride through** – an offshore HVDC terminal shall stay connected when its connection point voltage stays within a specified voltage-time series profile.

OFFSHORE START–UP REQUIREMENTS FOR OFFSHORE HVDC TERMINALS

- **Start–up of offshore AC grid** – an offshore HVDC terminal should perform essential control actions, in coordination with OWFs, switching (e.g. connecting and disconnecting AC umbilical line and/or the DRU in case of DRU-HVDC case) in order to start up the offshore AC grid.
- **Capability to control the offshore AC grid voltage** – an offshore HVDC terminal should control the offshore AC voltage by itself, by proper collaboration with OWFs or by correct combination thereof.
- **Offshore power quality** - offshore HVDC terminal characteristics should not result in fluctuation of supply voltage or a level of distortion of other electrical quantities in the offshore AC network, at the connection point, exceeding specified levels.

ROBUSTNESS AND STABILITY

- **Robustness and stability**- an offshore HVDC Terminal should allow for necessary control actions to prevent or help damping electrical oscillations in the offshore AC grid.

DRU ASSUMPTIONS

- DRU-specific requirements are introduced in the grid codes. DRU connections in the considered topologies comply with these requirements.
- In the case of a DRU converter at the offshore point of connection, the operational requirements will be suffered by OWF operator. Power flow control functions are fulfilled by OWF and WTG controllers.

MESHED GRID ASSUMPTIONS

- **Network Code HVDC and Network Code RfG** take into account a meshed configuration and lay a necessary basis of requirements for the interface between the MOG and OWF. Topologies that are considered in this Deployment Plan comply with these requirements.
- **Frequency-sensitive mode (FSM) and limited frequency sensitive mode (LFSM) requirements** are reviewed for the system consisting of 100% power electronic devices. Topologies considered in this Deployment Plan can be operated.

MESHED OFFSHORE GRID – OFFSHORE CONSUMPTION

Within the framework of PROMOTioN, the connection of offshore consumption is regarded as "out-of-scope" due to its negligible scale. Considering increased level of utilization of the Ocean Space, a few new categories of potential power consumptions which can be connected to the MOG are expected:

- Deep Sea Mining
- Offshore Aquaculture
- Offshore desalination for fresh water production
- Offshore charging facilities for electric ships

This offshore loads usually have a lower power rating (20-300 MW) than those of the OWFs, which range from 600MW up to over 1000MW. Potentially such loads will be aggregated or clustered and then connected to the MOG. It is likely that any offshore consumption will have higher reliability requirements than evacuation of energy.

Such requirements should be met in the most cost-effective manner, not necessarily exclusively by the MOG itself, as it might not need that level of reliability for its own operation. However a MOG could provide a part of this security of supply, providing power loaded backed by onsite generators and the existing dedicated cable connections.

MESHED OFFSHORE GRID – OPERATION

The HVDC terminal does not only consist of power electronics based units, but also the supervisory control units, which might be needed to continuously communicate with the OWFs. The assumption is that the relevant requirements are satisfied by considered topologies. An exact formulation can be found in Deliverable 1.7.

ASSUMPTIONS AND REQUIREMENTS FOR HVDC TERMINALS

- Operational ranges
  - **HVDC voltage range** – the HVDC terminal should stay connected and operable at determined DC link voltage levels and time periods. Automatic disconnection will be allowed at determined HVDC voltage levels.
  - **Rate of change of DC voltage** – the HVDC terminal should stay connected and operable if the HVDC voltage changes at up to a determined rate.
- Power and DC voltage response
  - **DC voltage response processing** – the HVDC terminal receives a measured DC voltage (or power) signal from a connection point, within a determined time period from sending to completion of processing the signal for activation of the response.
  - **DC voltage response activation** - HVDC terminals should activate power DC voltage response with an initial delay and provide active power frequency response for a determined duration.
  - **DC voltage response parameterization** - HVDC terminals should provide active power response based on a set of determined parameters, which allow for the calculation of the active power (or DC current) as a function of the DC voltage (or power).
  - **Coordination with OWFs for onshore frequency support** - For an offshore HVDC terminal connecting OWFs, with regards to DC voltage response, the offshore HVDC terminal and OWF have to agree on the technical requirements to achieve fundamental support for DC voltage response.
- **Robustness and stability** – the HVDC terminal should convert to a new stable operating point for a minimum change in active power flow and voltage level, during and after any planned or unplanned change in the HVDC system.
- HVDC terminal behaviour during short – circuit faults
  - **HVDC terminal response to DC grid faults** – the terminal should be equipped with all needed schemes to protect it against overcurrent and under and overvoltage in case of DC grid faults.
- Start – up requirements of HVDC terminals
  - **Start–up of DC grid** - some HVDC terminals should perform necessary control actions in order to start-up the DC grid.
  - **Power quality requirements** - HVDC terminal operation should not exceed specified levels of fluctuation of voltage supply, distortion and other electrical quantities at its DC side connection point.

MESHED OFFSHORE GRID – CONTROL

It is assumed that the relevant requirements are satisfied by the considered topologies. Furthermore, any of the requirements which are anticipated but not formulated yet, are assumed not to hamper any of the considered topologies. An exact formulation can be found in Deliverable 1.7.

DC CONTROL ASSUMPTIONS AND REQUIREMENTS

- Coordination of power flows:
  - A future meshed DC grid consisting of many VSCs technically will be able to provide very fast changes in direction of flows. It is assumed that operators develop new coordinated control mechanisms to take advantage of these capabilities. The “standard values” for the different parameters that can be used in control loops of offshore HVDC grids are developed.
  - Coordination between DC converters in the same synchronous area can allow the TSO(s) to have more control and realise additional benefits such as optimal power flows. Such coordination requires the detailed analysis and agreements between different operators taking into account the constraints of the AC grid.
  - Depending on planned outages and the forecasted wind production, changing the DC grid topology may be required. Therefore, the scheduling process should consider the possibility to change the DC grid topology, either in a manual way or in an automatic way (i.e. optimal transmission switching).
- Control:
  - DC voltage will likely be used as a tool for power flow control over DC lines and the normal DC voltage range may need to be extended. This control involves a droop control that will adapt the active power set point. It is assumed that the control is correctly implemented and voltage and thermal limits are not violated.
  - Imbalances can occur in an offshore grid due to forecast errors. To cope with small imbalances, local control can be implemented at the converter sides. It is assumed that the impact on harmonic generation is minor or can be dealt with.
  - For power oscillation damping, it should be specified when and whether the POD[35] controller should use the reactive power/voltage control or the active power control. Using the active power control in the first AC grid may affect all other grids.
  - Partial restoration of a meshed grid after a fault requires the implementation of a reliable remote-control system able to change the configuration of each DC bus (when de-energised) and isolate faulted part of a grid.
- Ability of the system to receive instructions and active power set points:
  - Maximum allowed increase or decrease of power set point is specified for adjusting the transmitted active power.
  - Minimum active power transmission capacity for each direction, below which the active power transmission power capacity is not requested.
  - Maximum time delay between receipt of the TSO request and start of the active power level adjustment.
  - Adjustment of the ramping rate, the ramping rate does not apply in case of fast power reversal or in case of disturbance to the AC system.
  - Fast response in case of disturbance on the AC network, with a maximum allowed delay.

[35] POD- Power oscillation damping controller

- The communications schemes must be fully redundant.
- The SCADA (Supervisory Control And Data Acquisition) system is essential for the remote control and monitoring of DC grids. Two types of SCADA systems will be part of the DC grid:
    - Wind farm SCADA
    - DC grid operator SCADA
- Protection and control requirements can be different depending on the chosen protection methodologies/philosophies and the connected grids.

BUSINESS-AS-USUAL

For the business-as-usual concept, limited amount of degrees of freedom exist between the results of the market-clearing and the operation of the grid. Certainly, HVDC systems connecting OWFs evacuate the generated offshore wind energy and point-to-point interconnectors transfer the cross-border power flows resulting from the market. Considering the fact that there is no possibility to change the topology, the optimization of the DC grid topology is unnecessary, hence is not recommended. Nonetheless, AC grid constraints can lead to offshore wind curtailment, as well as the limited ampacity of HVDC systems in case of overplanting. Additionally, considering several HVDC interconnectors connecting two areas, it is suggested that the power flow on each interconnector should set to minimise the losses while satisfying the operational criteria, including AC grid constraints. Control challenges might be expected mainly for DRU connections of OWFs as other parts of the concept (e.g. point-to-point interconnectors, VSC connections of OWFs) already exist in real power systems.

NATIONAL DISTRIBUTED HUBS

Considering the national distributed hubs concept, there is a wider mismatch between the market clearing and the setting of converters. Firstly, as an offshore HVDC grid could have several connection points in a specific bidding area (e.g. in a specific country), there are many possible ways to set the power flows through converters such that the offshore wind energy is evacuated and that cross-border flows are met. Moreover, topological actions are possible to influence power flows in the grid. Since for a specific country the national offshore and onshore grids are strongly connected (i.e. the power-sharing between converters impact both the offshore grid and the offshore grid), it is recommended for the scheduling process to take into account these two grids in a coupled way, which could be accomplished either with a single TSO or with two different TSOs with a coordination entity. Secondly, the compensation of imbalances due to wind generation variability and forecast errors can be performed on a national basis and necessitates a specific control strategy as well as reliability margins on transmission elements. Thirdly, the N-1 security criterion can influence strongly power flows within the grid and the need to optimise voltage droop control to maximise the available transfer capacity. It is advised to apply a fast master controller at a national level to quickly re-dispatch and/or curtail wind after a contingency in order to avoid sustained overloads and unacceptable voltage conditions. Finally, unique switching strategies are recommended to quickly restore the grid after a fault.

EUROPEAN CENTRALISED HUBS

In this concept, the hubs are decoupling points. Surely, OWFs will be connected radially (in AC or through a point-to-point HVDC system) and hubs will be connected through point-to-point HVDC systems to the onshore grids and between them. Similar to the BAU concept, power flow in transmission elements (including converters) are almost a direct consequence of the market-clearing result. AC grid limitation can also lead to offshore wind curtailment. The topology of the AC parts of the hub could be changed, but this is not recommended since no

benefits are expected from this possibility. This is because power flows are already individually controllable. Nonetheless, since several OWFs are connected to several HVDC systems, it is recommended to define and implement a control strategy to share imbalances between different converters. Note that the outage of a transmission element will induce a power imbalance on one or several hubs and thus an individual control strategy is suggested to deal with both outages and forecast errors. Additionally, the security of the system following faults and outages within the AC hub must also be guaranteed. Finally, the question of the partial restoration of the grid after a fault is irrelevant in this concept because HVDC systems can be protected separately.

EUROPEAN DISTRIBUTED HUBS

The control and operation considerations for the European Distributed Hubs concept are almost the same as the ones related to the National Distributed Hubs concept, with the additional complexity that they cannot be conducted nationally anymore. Moreover, a fast master controller is recommended to be used at an international level to quickly re-dispatch and/or curtail wind after a contingency to avoid sustained overloads and unacceptable voltage conditions.

STABILITY AND CONTROLLABILITY

System stability is the ability of an electric power system, for a given initial operating condition, to return a state of operating equilibrium after being subjected to a physical interruption, with most system variables bounded so that practically the entire system remains intact. This means the system has a few requirements:

- The system is stable to small signals[36].
- The system is stable to load changes. Power systems are continually subjected to load changes, thus a power system is able to adapt to changes in the power balance.
- The system is stable to large signals related to specific contingency scenarios as given in WP4 (Deliverable 4.1)[37]. After clearing the fault the system has to return into a (new) equilibrium.)
- The aspects of stability are considered on the DC grid within all converters and its controllers as well as on the OWFs.
- The stability of control has to be assured for every relevant outage. The controller affecting the states in AC offshore and DC grid in steady-state and fault case may not act against each other.

The rationale behind these requirements and assumptions mostly comes from the results of work by WP1, WP4 and Deliverable 12.1, and is not presented here. Provided that the above criteria can be respected by an offshore HVDC grid, the MOG can be implemented.

PROTECTION SYSTEM

Power systems are often exposed to faults on transmission elements (e.g. cables). To provide a safe, reliable and continuous operation of power systems, mentioned faults must be quickly located, detected and cleared. In AC transmission systems, protection systems and circuit breakers often protect individually each transmission element. If a fault takes place in an AC transmission system, the specific faulty element can be separated from

[36] Small signal stability refers to the ability of the system to operate reliably in non-fault conditions and stay in equilibrium when exposed to small deviations from the operating point e.g. changes in wind power generation or small voltage dips. Small signal stability mostly relates to a sufficient damping of the system.

[37] Large signal stability refers to the behaviour of the system in a faulted condition when subjected to strong disturbances like short circuits or loss of a significant component (e.g. large generator).

the rest of the system in tens of milliseconds. Protection of DC transmission systems is much more demanding for two main reasons. First, DC faults lead rapidly to high currents and must be broken much more quickly than AC faults since components have a limited overload capability. It is suggested that they must be detected, located and cleared in a couple of milliseconds. Second, DC faults do not exhibit regular zero-crossing, contrarily to AC faults, and their disturbance is thus much more challenging. It suggests that DC circuit breakers are expected to be much costlier than AC circuit breakers.

The objective of this section is to present the protection system assumptions in a form of requirements which are assumed to be fulfilled by any of the considered topologies. Nonetheless, a few specific, topology-related issues which will be typical for instance for the distributed concepts and not so typical for the centralised concept. These are described in a more detail in the subsection below.

DC PROTECTION ASSUMPTIONS AND REQUIREMENTS

- The requirements related to robustness and general disturbances are as follows:
  - The DC grid protection system should not operate in case of power flow changes during normal operation (e.g. power order change), AC faults, outage of a converter, energisation/dis-energisation of a converter, cable or overhead line.
  - The DC grid protection system should not operate in case of a DC fault external to its designated protection zone.
  - The DC grid protection system should be reliable regardless of changes in the grounding schemes, like variation of grounding location, metallic/ground return operation of a bipolar configuration.
  - The DC grid protection system should be reliable regardless of variations in the grid topology at the bus, like changing of the number of the parallel branches due to busbar switching actions, maintenance, fault or expansion of the DC grid.
  - The DC grid protection system has to be robust to manage different busbar configurations such as single busbar with breakers, breaker-and-a-half scheme, double busbar with breakers.
  - The DC grid protection system should be reliable in the presence/absence of auxiliary components, such as DC choppers in the case of windfarm application.
- The reliability and availability targets:
  - Are addressed on case-to-case basis, in order to design a system which is neither nor too oversised nor too poorly designed.
- Requirements connected to multi-vendor protection of DC grid:
  - The DC grid protection should be designed that it has standardised interfaces. Standardization should be determined both for system and component level.

AC SYSTEM CHARACTERISTICS

Apart from the general non-functional requirements, there should be made assumptions regarding the AC grid limits which define how the protection system operates.

Criteria	Options	Comments
Maximum loss of power infeed.	• The transient loss • The temporary loss • The permanent loss	• Continental Europe 3 000 MW • Nordic 1 350 MW • Great Britain 1850 MW • Ireland and Northern Ireland up to 500 MW
Maximum active		• Germany, an upper ramp rate limit of 10% of grid

power ramping rate		connection capacity per minute • Ireland, a ramp rate of 1 – 30 MW/min • Nordic grid code, an upper ramp rate limit of 600 MW/hour • Denmark, a ramp rate 10 – 100% of rated power per minute.

DC SYSTEM CHARACTERISTICS

Despite the general non-functional requirements, there should be made assumptions regarding the DC grid limits which define how the protection system operates.

Criteria	Options	Comments
Minimum DC voltage level	• 0.95 p.u.	• Minimum DC voltage level (during normal operation).
Maximum DC voltage level	• 1.05 p.u.	• Maximum acceptable DC voltage during normal operation which will not cause component malfunction.
Nominal current	• 1.5-2 kA	
Maximum current rate of rise	• 1-10 kA/ms	The maximum current rate of rise at a given point in the DC system. The maximum current rate of rise for a given fault clearing strategy can also be an outcome of the study.
Maximum transient current	• 5-20 kA	• Maximum current occurring at a given point in the DC system.

PROTECTION STRATEGY

The protection requirements are specified by the assumptions of the DC grid and the connected AC power systems, adjusting the likelihood of faults and their effects. Overall, DC grid protection becomes more inconvenient when going from smaller systems (point-to-point) to more complex (e.g. large and meshed) grids. Point-to-point projects are protected on the AC side using AC breakers. For radial multi-terminal and meshed multi-terminal grids, the results of a fault event at the DC side is expected to require additional protection, for example, to avoid passing the maximum loss of infeed to a single synchronous area limit. The assumptions on the specific protection strategies, their performance and utilisation are given below.

FULLY SELECTIVE STRATEGY

In this kind of DC grid protection philosophy, protection zones are defined to individually protect each DC line and bus.

PARTIALLY SELECTIVE STRATEGY

For this protection philosophy, the DC grid is divided into many protection zones or sub-grids. The loss of the whole DC grid is avoided thanks to quick isolation of the healthy zones from the faulted zone. For this strategy to be completely viable, each separate zone must not be larger than the maximum loss of infeed limit of a single synchronous area that is influenced by that zone. Partially selective fault clearing strategies therefore depend on the proper placement of DCCBs or DC/DC converters to split the grid into separate zones. When the topology of the grid changes because of the addition of new DC lines and/or converter stations, the original grid splitting solution might no longer be valid.

NON SELECTIVE STRATEGY

In the non-selective strategy AC breakers and FB converters are used as it is done for point-to-point connections. This protection philosophy considers the DC grid as one protection zone for fault clearing, i.e. no selectivity for fault current interruption within the DC grid. In case of a DC side fault, the whole DC grid is de-energised from the moment of fault detection.

UNITY

Most often a single protection strategy is implemented within the grid. However, sometimes single grid parts can have individual protection strategies. The transformation from a single protection strategy into different strategies generally may happen during the grid development, form basic (point-to-point connections) into an advanced one (meshed grid). Various strategies allow for more flexibility to form the national point of view.

PROTECTION STRATEGY PER CONCEPT

All concepts

Circuit breakers

- Protection on the AC side is done by the use of AC circuit breakers. Opening of AC circuit breakers therefore disconnects the DC line in a point–to-point connection. As such, HVDC circuit breakers are not needed for point-to-point connection, they are applied only for meshed solutions. AC circuit breaker costs are not taken into account in the CBA.
- Type of busbars used on the hubs (double, single, ring.)

DC circuit breakers

- Multi-line breaker technology as described in Deliverable 12.1 is out of scope of the CBA.
- DCCBs may take form of mechanical or hybrid units.
- Additional platform space is needed for hybrid DCCBs and no additional platform space is needed for mechanical DCCBs.

National Distributed

Circuit breakers

- DC circuit breakers are installed in places where there is no point-to-point connection present.
- The DC protection strategy is based on the implementation of DCCBs. The preferred technology is mechanical DCCBs, however, their behaviour under high voltages must be studied.
- DCCBs are installed only where a single contingency leads to a loss of power infeed in the AC network higher than the reference incident of that zone.

Protection gear

- GIS has low maintenance, high reliability and is used where space is limited e.g. on an offshore platform. GIS is only needed on platforms in meshed situations, as it is part of the protection technology.

European Distributed

Circuit breakers

- DC circuit breakers are installed in places where there is no point-to-point connection present.
- DCCBs are used for DC protection. The preferred technology would be mechanical DCCBs (lower mass and volume). However, their behaviour under high voltages must be studied.
- DCCBs installed only where a single contingency leads to a loss of power infeed in the AC network higher than the reference incident of that zone.

Protection gear

- GIS has low maintenance, high reliability and is used where space is limited e.g. on an offshore platform.
- GIS is only needed on platforms in meshed situations, as it is part of the protection technology.
- On the shore, it can be more convenient to install AIS, since there is not that significant space limitation.

SECURITY CRITERION

The safety criterion that is considered is the loss of infeed in the synchronous zone. Where an HVDC system connects two or more control areas, the relevant onshore TSOs must consult each other in order to set a coordinated value of the maximum loss of active power injection, taking into account common-mode failures.

DEPENDENCE ON VOLTAGE LEVEL

The protection system does not depend on the voltage level. This is due to the fact that it is crucial to protect the grid from loss bigger than the maximum reference incidents in Europe (Table 6). Therefore the voltage level defines only the protection equipment ratings.

TYPE OF GROUNDING

MONOPOLAR

- Grounding through star point reactor:
  - Complexity of star point reactor design
  - Choice of converter stations that need to be grounded through the star point.
- Grounding through converter transformer:
  - Transformer neutral point treatment.

BIPOLAR

- In case of metallic return:

How to perform grounding at each converter station in order to avoid DC current flow through ground:

  - Placement of metallic return, cost related to separated trench in order to improve reliability.
  - Choice of voltage insulation level of the metallic return.
- DC choppers

DC choppers used for a DC voltage limitation in case of DC pol-to-ground faults. DC choppers are applied in most offshore point-to-point connections.

- DBS- Dynamic Breaking System

Required in case of symmetrical monopole scheme for voltage rebalancing after fault clearing - can be seen as a specific HVDC converter.

PROTECTION EQUIPMENT

The assumptions about the ratings and capabilities of protection equipment, like DCCB, ACCB, fault current limiting reactors and switches are presented below. Moreover, these tables present also capabilities of converters and cables related to protection and safe operation.

Criteria	Options	Comments
TRL	• Hybrid • Mechanical	• 7 • 6
Location/ topology	• Protect each branch with DCCB • Protect only critical branches • Point to point connection	• Can be installed on all meshed cables. • Installed on those cables that, if subject to fault, would cause a potential loss of power infeed in the onshore AC zone higher than the reference incident of that zone. • DCCBs are not required for radial point-to-point connection of OFWs.
Type	• Hybrid • Mechanical • Unidirectional • Bidirectional	• If only hybrid DCCBs are technically applicable for the power levels and voltage present in the offshore grid, only OFWs far from the shore (more than 100 km) will be part of the offshore grid. • If mechanical DCCBs can be used as well, OWFs closer to the shore also can be integrated. • Mechanical DCCBs are developed for voltage ratings of about 100kV. • Unidirectional breakers only trip if the DC fault current path is in the forward direction.
Onshore points	• When clustered – need to use DCCB • Do not cluster to avoid using DCCB	• If DCCBs were used it can be possible for the onshore converter station to remain connected as a STATCOM and provide ancillary services to the onshore AC network.
Voltage	• Hybrid 320 (80 - 525) kV • 320 (80 - 525) kV	• Currently available 80-100 kV needed – in order of 500 kV. DC breakers are not yet implemented in real applications. However, the prototypes have been tested at lab-scale (Voltage <100 kV).
Fault current suppression	• 2-3 ms hybrid DCCB • 5-8 ms mechanical DCCB	• Sequence involving the fault current suppression, i.e., from breaker opening instant until zero current through the breaker.
Fault current interruption capability	• Hybrid : 5 – 18 kA • Mechanical : 10 – 16 kA	• The maximum fault current that can be interrupted by a circuit breaker without failure of the circuit breaker.
Rated peak fault breaking current	• Hybrid 4 - 20 kA • Mechanical 6-20 kA	• The short-circuit current that the circuit breaker can withstand as it is closing where the act of closing initiates the fault.
Maximum breaker surge arrester voltage	• 1.05 p.u.	• Maximum protection voltage of surge arrester
Bypass delay		• Bypass delay is the maximum time which a hybrid DC circuit breaker can operate in current limitation mode prior to current breaking by the main DC breaker
Breaker operation time (T_{brk})	• Mechanical 5 - 20 ms • Hybrid 2 - 5 ms	
Breaker opening time	• Mechanical : 5 - 10 ms • Hybrid 1.5-3 ms	
Size		• Hybrid circuit breakers much bigger than mechanical one. • Additional platform space is needed for hybrid DCCBs and no additional platform space is needed for mechanical DCCBs.

Available	• No	• Possibly will be available in the future, TRL 7 and 6.
Mean time to failure	• 160000 hours	
Mean time to repair	• 6 hours	

ACCB

Criteria	Options	Comments
Voltage	• 150 kV • 170 kV • 420 kV	• Depending on the protection strategy, type of hubs, etc. AC breakers may be used instead of DC.
Mean time to failure	• 160000 hours	
Mean time to repair	• 6 hours	

HVDC GIS

GIS has the same function as AIS. The main difference between these two components is insulating gas. For AIS its air and for GIS SF6 or mixtures of gases. Objectives of GIS and AIS are to de-energise equipment to allow work to be done and to clear faults downstream. The compact and metal-enclosed design of GIS has prominent advantages and better performance than AIS. However, the high initial investment is a key obstacle in expanding the application of GIS. In a remote or rural area or in developing countries, AIS is still the best choice. In places where the cost of land or cost of earthworks is high (e.g. offshore platform) the solution is to use GIS. Next pros of GIS is the fact that the failure rate of disconnecting switch and circuit breaker in GIS is 25 % of AIS and 10 % in case of busbar, hence the maintenance cost of GIS is less than that of AIS over the lifetime [8].

Criteria	Options	Comments
TRL	• 320 kV • 500 kV	• 6. Assumed to become available in the near future. • 5. Assumed to be 9 in the near future.
Type	• GIS • AIS	• GIS – immature technology. Reduced size, but more expensive. • AIS – bigger and cheaper.
Voltage	• 320 kV • 525 kV	• Depends on overall network design.
Gas type	• SF6 • FN-CO2 mixture • FK-Air	• SF6- the most potent greenhouse gas will be replaced by a mixture of a very low greenhouse warming potential (GWP <1) • Alternatives, FN-CO2 mixture, FK-Air still have to be investigated.
Availability		• Available in the nearest future TRL 6.
Platform size reduction		• GIS substations, require significantly less space than AIS.
Mean time to failure	• Full reliable	
Mean time to repair	• Full reliable	

SHORT CIRCUIT FAULT CURRENT LIMITER (SCFCL)/ DC REACTOR (PART OF DCCB)

Criteria	Options	Comments
TRL	• Reactor • SCFCL	• 9 • 2, no prototype for HV application - no industrial

		product for HV applications
Type	• Reactor • SCFCL- Super conducting fault current limiter	• Reactor used to limit the magnitude of the fault current occurring in the protection zone of the circuit breaker. • Guarantee continued controlled work of the healthy part of the system by avoiding the voltage collapse of the entire DC grid during the fault neutralization time. • Reactor cost depends on quantity. • SCFCL – new and highly prospective component, but could be considered as a not critical component as many protection solutions would not require SCFCL.
Location	• At both ends of the cable • At one end of the cable • Location on the busbar when decoupling	• The placement of series reactors at the ends of cables limits/reduces the rate of rise of fault currents. The higher the inductance of the reactor, the slower the rate of rise of current. As a result, the voltage drop at the converter before blocking will be smaller.
Size	• 100 mH • 150 mH	• Size of the inductance influences the design of DC breaker. Depends on the breaker operation time. (100mH used with 2ms and 150 with 8ms)
Availability		• Reactors are commercially available TRL 9. • SCFCL potentially will be available in the distant future.

HIGH SPEED SWITCH (HSS)

Criteria	Options	Comments
TRL	• Disconnector • HSS	9 Unknown
Type	• Disconnector • HSS	
Location	• At both ends of the cable • At one end of the cable • Location on the busbar when decoupling	• HSS placed in series with the DC circuit breakers.
Opening time	• 5-20- ms	• Time delay related to switch opening, i.e., time duration between the switch tripping instant and the instant at which the switch is able to start residual current interruption.
Reclosure time		• Time duration between switch operation and regaining the ability of reclosing.

SURGE ARRESTERS

Criteria	Options	Comments
Type	• AC • DC	• Without surge arresters overvoltages in the system can cause breakdown of the equipment insulation because of lightning strokes into the electric power system, on the station itself or into its proximity.
Location	• Close to the termination of incoming AC lines • Close to the transformers • At the top of the	• AC surge arresters located close to the termination of incoming AC lines and close to the transformers to give protection against lightning surges. • DC surge arresters protect the DC switchyard equipment linked with the DC pole.

	cascaded sub-modules	
Energy absorption capability	• Hybrid 4 – 20 (30) MJ • Mechanical 1 - 30 MJ	• Maximum energy which an arrester is able to dissipate.
Rated voltage of an arrester	• 1.2-1.3 / 1.03	• Maximum permissible root-mean square value of power-frequency voltage between the arrester terminals at which it is designed to operate correctly under temporary overvoltage conditions as established in the operating duty tests.
Continuous operating voltage	• AC 1.2-1.3 p.u. • DC 1.2-1.3 p.u.	• Permissible rms value of power-frequency voltage which is allowed to continuously be applied between arrester terminals
Lightning impulse protection level	• 2.1/1.744 p.u.	• Maximum value of the residual voltage of an arrester at lightning current impulse.
Switching impulse protection level	• 1.916/1.614 p.u.	• Maximum value of an arrester's residual voltage at standard switching impulses.

CABLES

Criteria	Options	Comments
Lightning impulse withstand level (p.u.)	• 2.1 p.u. (same polarity)	• Withstand voltage of insulation to standard lightning impulse
Switching impulse withstand level (p.u.)	• 1.916 p.u. • 1.2 p.u. (opposite polarity)	• Withstand voltage of insulation to standard switching impulse
Temporary overvoltage withstand level (p.u.)	• Not standardised in test procedures for cables, yet.	• Withstand voltage of insulation for a few milliseconds to seconds
Maximum continuous withstand voltage	• 1.05 p.u.	• Maximum continuous DC voltage which is allowed on a cable line for continuous operation.
Maximum continuous withstand current	• Not standardised in test procedures for cables, yet.	• Maximum current which a cable can carry.
Thermal overload limit	• Not standardised in test procedures for cables, yet	• Maximum current and duration which is allowed on a cable/overhead line under overloading operation.
Maximum rate of change of voltage	• The typical lightning and switching profiles, e.g. ~1.2 µs for the increase towards 90%	• Maximum ramp up speed which is allowed on a cable/overhead line for safe operation.

VOLTAGE SOURCE CONVERTERS

Criteria	Options	Comments
Safe operating area (SOA)	• This is typically a curve which depends on the chosen IGBT, therefore there is no single number.	• SOA is a voltage and current area within which the power electronic switch can be safely turned on and off. The IGBTs within a converter should be blocked before this component limit is exceeded.
Diode/ thyrisor surge withstand capability	• 0.520-0.911 kA2s	• Surge withstand capability is limited by the maximum allowed junction temperature and is a function of the the power dissipation (i.e. I^2t) and thermal impedances

DC fault ride through capability	• No standard available yet.	• Voltage-against-time profile at the connection point of a converter to the HVDC grid, which defines transient undervoltage, transient overvoltage, and durations, within which the converter must stay connected and continue uninterrupted operation (i.e., no permanent loss of power).

LEGAL & REGULATORY, ECONOMIC AND FINANCIAL ASSUMPTIONS

Appropriate legal, regulatory, economic and financial frameworks will enable investment in Meshed Offshore Grid assets and coordinated operation with all neighbouring North Seas countries. Deliverables 7.2, 7.4 and 7.6 set out recommendations for the legal & regulatory, economic and financial frameworks for a Meshed Offshore Grid in detail. These are combined into a final set of policy recommendations in Deliverable 7.9 which are summarised in Chapter 4 of this report.

Assumptions

The development of the frameworks assumed that:

- The recommendations had to be 'grid-concept' neutral. That is to say that they could be applied to any configuration of grid assets
- As with the rest of the PROMOTioN project, power-to-gas offshore was considered out of scope

In addition, the reports were written during the period when the UK was preparing to exit the European Union. The recommendations were made based on the current political set-up, but acknowledges where the UK's exit from the European Union may cause uncertainty or require changes to the recommendations made.

Decision making criteria

Where applicable, proposed options for different elements of the legal & regulatory, economic and financial frameworks, were assessed qualitatively against four criteria to reach a preferred option. The four criteria were defined in Deliverable 7.2 as:

- **Costs/benefits:** The relative costs & benefits of one option compared to the other options. Absolute costs & benefits were not compared as it is often difficult to estimate these with certainty. In general, options that stimulate development towards a MOG are deemed more beneficial than options that lead to radially connected OWFs, as the meshing provides societal benefit through the interconnection of different electricity grids. Transaction costs and other costs are also taken into account where relevant.
- **Speed of Implementation:** This parameter relates to both the time needed to implement a certain option (e.g. a change in regulation) and, after implementation a change, the impact this has on the speed of development of the MOG.
- **Socio-political acceptance**: socio-political acceptance is subjective to assess. In the current political situation, options for which national authority needs to be transferred to the EU or to another supranational organisation are scored negatively, as some states (notably non-EU (third) states) will probably not accept this. Also, distribution of the costs according to which state reaps the benefits is considered fairer and scores more positively than every state pays an equal share. For aspects of the framework such as decommissioning, options that adhere to the principle of 'polluter pays' score higher than options that disregard this principle.
- **Provision of Private Capital:** this parameter scores to what extent investors will be willing to provide private capital for the development of the MOG. Issues that influence the scoring for this parameter are

stability, creating a level playing field, ability to win back the investment and long-term foresight of how the MOG will be regulated.

The comparison of options using these four parameters is set out in the final Work Package 7 deliverables.

OUT OF SCOPE

The PROMOTioN project is designed to demonstrate how newly developed technology such as HVDC Circuit breakers, DRUs and GIS can be combined to deploy an efficient and reliable grid for the evacuation of OWF generation to shore. To deliver this analysis within the timeframe of the PROMOTioN project, boundaries on the scope of the analysis were established. Topics which were out of scope of the PROMOTioN analysis are summarised below along with commentary on their potential impact on MOG development.

OFFSHORE ELECTRICITY CONSUMPTION

The connection of offshore consumption to the offshore transmission network is regarded as "out-of-scope" due to its negligible scale compared to offshore wind generation. Out to 2050, offshore electricity consumption may be required for:

- Deep Sea Mining
- Offshore Aquaculture
- Offshore desalination for fresh water production
- Offshore charging facilities for electric ships

These offshore loads usually have a lower power rating (20-300 MW) than those of the OWFs, which range from 600MW up to 2000MW. A MOG could meet this requirement via dedicated connections. However, it is likely that offshore consumption will have higher grid reliability requirements than evacuation of energy. Such additional requirements should be met in the most cost-effective manner, not necessarily exclusively by the MOG itself, as it might not need that level of reliability across its entire network. For example, back-up generation and/or storage at the offshore consumption sites could provide additional security.

ONSHORE GRID

Evacuating increasing amounts of offshore generation to shore will have implications for the reinforcement of the onshore network. The CBA in PROMOTioN considers the direct near-shore onshore grid reinforcements required at onshore/offshore connection points to enable evacuation of wind power to shore. However, it does not considered wider reinforcements required, or reconfigurations of the network required as a result of the switch from non-renewable sources of electricity to increasing levels of offshore wind. These changes could include:

- Reinforcement of onshore transmission lines and substations to transmit power from coastal connections to centres of consumption (e.g. the German Ruhr located near the border with the south-eastern part of the Netherlands)
- Decommissioning of assets connected to fossil-fuel power stations.
- Investment in, and management of, distributed storage assets, which could reduce the network cost of using renewable generation from intermittent sources.

In addition, the PROMOTioN analysis does not consider whether the offshore network could be a cost-effective means of reducing the requirement for onshore reinforcement (similar to the Western HVDC link from Western Scotland to North Wales in the UK).

Finally, WP2 recommended that more research is undertaken on operation and control concepts for the integrated operation of AC and DC systems. As the AC onshore grid is not considered within PROMOTioN, this has not been further researched. However, bringing together two different large-scale systems requires an adapted strategy on the operation and control of these two systems in harmony. Different strategies may be possible, which would need to be researched.

Extending the scope to include wider onshore networks was considered infeasible within the original scope of PROMOTioN, as it would require the onshore grids of the North Seas countries (and how these will develop to 2050) to be modelled in detail. This would entail further research into the development of demand for energy, supply of energy, price fluctuations, synergies between electricity and heat, policy, etc. for each individual North Seas country and even surrounding countries. This would require significantly more time, data and different consortium partner expertise, than available within PROMOTioN.

POWER TO GAS

Power to gas could be a means of electricity storage in the offshore grid. Electrolysis on offshore platforms would convert electricity to hydrogen which could be used directly (either offshore, or by being piped to shore), or converted back to electricity for export at a later point in time. However, within PROMOTioN it is assumed that all offshore wind energy generated must be directly transported to shore. This means that at times of full production, the DC cables will have to be capable of transporting all this energy to shore.

Offshore power to gas facilities would be able to exploit fluctuations in wind energy generation to store energy at times of high energy production and release this energy at times of low energy production. This enables cable connections to shore to be scaled more optimally and also adds value to the operation of the onshore grid, as the wind energy would be a far more stable energy supply[38]. In particular, large centralised concepts such as the HUB concept could benefit from offshore power to gas, as the wind energy is already collected in a central point and distributed from there. This means that an offshore power to gas facility could be of a large scale and provide its benefits to a lot of OWF capacity at once. However, it should be noted that the conversion of power – to –gas – to-power incurs significant losses which would need to be considered in any CBA.

Onshore power to gas (in coastal locations) wouldn't reduce the need for offshore transmission assets, but may minimise onshore reinforcement requirements. An onshore power to gas facility may however alter the offshore topology, if corridors of large capacity could be connected to a single onshore connection point, where power to gas facilities are situated to provide back-up when necessary.

Currently, the use of power to gas offshore is not commercially deployed and full-scale tests are limited to a very small capacity. The impact of power to gas facilities on the offshore grid is therefore assumed only to affect the later stages of offshore grid development. High uncertainties in the costs and the rate of development of the technology have meant that this is not taken into account in the PROMOTioN CBA.

[38] Especially the intermittent character of renewable energy sources like solar and wind concerns TSOs when large capacities dominate the grid, as this means their generation is difficult to predict. This may lead to more forecasting errors of energy generation and thus the higher utilisation of additional generation capacity or even demand capacity to maintain the onshore grid stability. These resources are relatively expensive and therefore have its impact on the electricity price.

TECHNOLOGY DEVELOPMENT

PROMOTioN uses currently available costs for commercial or near-to-market HVDC assets and does not assume cost reductions out to 2050 due to a high level of uncertainty in the data. However, in reality, economies of scale, standardisation of technologies and innovation are likely to lead to cost reductions

IV. APPENDIX - STAKEHOLDERS

INTRODUCTION

This appendix provides a brief introduction to stakeholders relevant to the development of offshore wind and transmission in the North Seas. These include:

1. EU Institutions, Agencies & Councils
    a. DG Energy who oversee:
        i. North Sea Energy Forum
        ii. Ocean Energy Forum
        iii. Web-based Maritime forum
        iv. North Sea Maritime Forum
2. North Sea Wide Institutions
    a. North Sea Countries' Offshore Grid Initiative (NSCOGI)
    b. Conference of Peripheral Maritime Regions (CPMR)
3. Non-Sectoral Organisations with Energy Interests
    a. North Sea Marine Cluster (NSMC)
    b. OSPAR Commission, in particular the committee for "Environmental impacts of Human Activities."
    c. International Council for the Exploration of the Sea (ICES) Working groups on "Marine Renewable Energy," "Marine Planning & Marine Coastal Zone Management," and "Marine Benthal & Renewable Energy Development".
    d. Interreg North Sea Region Programme (Interreg/NorthSEE)
4. Energy Trade Bodies.
    a. ENTSO-E
    b. Ocean Energy Europe
    c. WindEurope
5. Governments / Member States
    a. Ministries responsible
6. National and Supranational Regulators
    a. ACER
7. TSOs
8. OFTOs
9. Wind Farm Developers
10. Investors, including the European Investment Bank (EIB) and the Connecting Europe Facility (CEF)
11. Manufacturers & Contractors.
12. Testing & Certification Agencies
13. Interconnector Owners (e.g. BritNed)
14. NGOs (Environmental, and other related)
15. Other related parties

EU INSTITUTIONS, AGENCIES AND COUNCILS

DG ENERGY

This Commission department is responsible for the EU's energy policy: secure, sustainable, and competitively priced energy for Europe.

NORTH SEAS ENERGY FORUM

The North Seas Energy Forum brings together representatives of the public, private and non-governmental sectors in the Northern Seas region to discuss challenges and opportunities and the role of stakeholders in realising the region's full energy potential.

NORTH SEA INSTITUTIONS

NORTH SEA COUNTRIES' OFFSHORE GRID INITIATIVE (NSCOGI)/ NORTH SEA COUNTRIES ENERGY COORDINATION COUNCIL (NSECC)

The North Seas Countries' Offshore Grid Initiative (NSCOGI) is a regional cooperation of 10 countries to facilitate the coordinated development of a possible offshore electricity grid in the greater North Sea area. NSCOGI seeks to maximise the efficient and economic use of the renewable energy resources as well as infrastructure investments. NSCOGI was formalised by a Memorandum of Understanding in 2010 following a Political Declaration in 2009. It is supported by the energy ministries, the regulators and transmission system operators of the 10 participating countries, as well as the European Commission.

NSCOGI is subdivided in Working Groups, concerning Grid configuration (Working Group 1), Regulatory issues (Working Group 2) and Planning and Permitting (Working Group 3) and steered by a Programme Board.

This project ended officially in 2016, but has continued as a forum for cooperation under the title North Sea Countries Energy Coordination Council (NSECC).

THE CONFERENCE OF PERIPHERAL MARITIME REGIONS (CPMR)

The CPMR is a think tank and lobby group on behalf of maritime regions across more than 24 states both within and outside the European Union[39]. It focuses mainly on social, economic and territorial cohesion, maritime policies and blue growth, and accessibility. European governance, energy and climate change, neighbourhood and development also represent important areas of activity for the association. It believes that marine energy sources are a huge opportunity to contribute to the research and innovation component of the Energy Union and that regional authorities can actively promote a low carbon economy across their territories and campaign for relevant polices at a national and international level.

[39] https://cpmr.org/policy-work/energy-climate/

NON-SECTORAL ORGANISATIONS WITH ENERGY INTERESTS

NORTH SEA MARINE CLUSTER (NSMC)

NSMC is a not-for-profit collaboration between business, scientific and academic expertise for the benefit of the regional marine sector, developing new avenues for marine science and service, and fostering collaboration across the marine-related sectors in the North Sea.

OSPAR COMMISSION FOR THE NORTH SEA REGIONS - THE COMMITTEE FOR "ENVIRONMENTAL IMPACTS OF HUMAN ACTIVITIES."

OSPAR is the mechanism by which 15 Governments & the EU cooperate to protect the marine environment of the North-East Atlantic. The fifteen Governments are Belgium, Denmark, Finland, France, Germany, Iceland, Ireland, Luxembourg, The Netherlands, Norway, Portugal, Spain, Sweden, Switzerland and United Kingdom.

OSPAR started in 1972 with the Oslo Convention against dumping and was broadened to cover land-based sources of marine pollution and the offshore industry by the Paris Convention of 1974.

OSPAR has developed guidance on environmental considerations for the development of offshore wind farms. This recommends best practices to assess, minimise and manage the potential impacts of wind farms.

INTERNATIONAL COUNCIL FOR THE EXPLORATION OF THE SEAS (ICES)

The International Council for the Exploration of the Sea (ICES) is an intergovernmental marine science organization, delivering impartial evidence on the state and sustainable use of seas and oceans. Their work aims to increase scientific understanding of marine ecosystems and the services they provide and to use this knowledge to generate state-of-the-art advice for meeting conservation, management, and sustainability goals. They chair several working groups relevant to offshore wind.

ICES WORKING GROUP ON MARINE BENTHAL AND RENEWABLE ENERGY DEVELOPMENTS

Benthic organisms have a fundamental place in marine ecosystems and deliver numerous ecosystem goods and services (such as marine biodiversity, long-term carbon storage and natural resources), which are intimately linked to the benthic system. Extensive renewable energy developments have the potential to initiate processes which are expected to affect benthic communities in numerous ways. The aim of the ICES Working Group on Marine Benthal and Renewable Energy Developments (WGMBRED) is ultimately to develop guidelines and an overview of existing data for cumulative impact research by future international collaboration. The outcomes will assist in improving monitoring concepts in the context of offshore renewable energy constructions and will also be set within the context of marine spatial planning strategies and future ecosystem-based management approaches.

ICES WORKING GROUP ON MARINE RENEWABLE ENERGY

The Working Group on Marine Renewable Energy (WGMRE) coordinates the flow of science between different working groups and its application in relation to offshore energy installations. WGMRE's remit includes correlating the science from groups on specialist topics such as seabirds, benthic ecology, and fish ecology and its application in planning, consenting and regulatory processes in relation to tidal (in-stream and barrage), wave and offshore wind energy. WGMRE provides information on the state of development of marine renewable energy and identifies future issues that will require environmental assessment. It also reports on consenting procedures and

assessment methods, fosters work across scientific disciplines, and improves understanding across human activities, for example interactions with fishing.

ICES WORKING GROUP FOR MARINE PLANNING AND COASTAL ZONE MANAGEMENT

The Working Group Marine Planning and Coastal Zone Management (WGMPCZM) focuses on marine spatial planning (MSP) and coastal zone management (CZM) in the ICES area. Based on current developments in marine planning practice and research, WGMPCZM focuses on knowledge gaps in MSP and risk analysis. It also looks at quality assurance of both advice for MSP and of processes in coastal and marine planning, social-cultural dimensions of ecosystem services and the use of fisheries data in planning decision-making processes.

INTERREG – NORTHSEE PROJECT

The North Sea Perspective on Shipping, Energy and Environmental Aspects in Maritime Spatial Planning (NorthSEE) is funded by the European Regional Development Fund and aims to achieve greater coherence in Maritime Spatial Planning (processes) and in Maritime Spatial Plans (capturing synergies and preventing incompatibilies; and create better conditions for sustainable development of the area in the fields of shipping, energy and environment protection.

Project Partners include national authorities from Germany, the Netherlands, Belgium, Scotland, Norway and Sweden, as well as regional authorities from North Holland and the Norwegian Environment Agency, Institute of Marine Research, Aalborg University, University of Oldenburg, the World Maritime University and NHTV Breda University of Applied Sciences (NL).

ENERGY TRADE BODIES

ENTSO-E

ENTSO-E[40] represents 43 electricity TSOs from 36 countries across Europe. ENTSO-E was established and given legal mandates by the EU's Third Legislative Package for the Internal Energy Market in 2009, which aims to further liberalising the gas and electricity markets in the EU.

ENTSO-E members share the objective of setting up the internal energy market and ensuring its optimal functioning, and of supporting the ambitious European energy and climate agenda. ENTSO-E contributes to the achievement of these objectives mainly through:

- Policy Positions
- The drafting of network codes and contributing of their implementation
- Regional cooperation through the Regional Security Coordination Initiatives (RSCIs)
- Technical cooperation between TSOs
- The publication of Summer and Winter Outlook reports for electricity generation for the short term system adequacy overview
- The development of long-term pan-European TYNDPs
- The technical cooperation between TSOs

[40] https://www.entsoe.eu/

- The publication of summer and winter outlook reports for electricity generation for the short term system adequacy overview
- The coordination of R&D plans, innovation activities and the participation in Research programmes like Horizon 2020 or formerly FP 7 (7th Framework Programme).

OCEAN ENERGY EUROPE

Ocean Energy Europe is a not-for-profit organisation and the largest network of ocean energy professionals in the world. Ocean Energy Europe's mission is to create a strong environment for the development of ocean energy, improve access to funding, and enhance business opportunities for its members. OEE's work involves engaging with the European Institutions (Commission, Parliament, Council, EIB, etc.), and national ministries on policy issues affecting the sector (it is an officially recognised advisory body to the EC on research priorities) and participating in publicly funded projects where there is a clear benefit to the sector as a whole.

WINDEUROPE

WindEurope actively promotes wind power in Europe and worldwide. It is a non-profit organisation consisting of over 400 members, active in over 35 countries. In addition to wind turbine manufacturers their membership encompasses component suppliers, research institutes, national wind and renewables associations, developers, contractors, electricity providers, finance and insurance companies, and consultants.

WindEurope lobbies governments and other institutions for a suitable legal framework for wind energy in Europe. It also organises numerous events, ranging from conferences, exhibitions, and launches to seminars and workshops on policy, finance and technical developments within the wind industry.

MINISTRIES RESPONSIBLE FOR OFFSHORE WIND

In each country there are multiple agencies involved in and influential in management and exploitation of the offshore environment, energy, offshore wind generation and transmission. In the lifetime of offshore wind development, from conception and permitting through decommissioning, a developer will have contact with many ministries and government departments, including those relating to Energy, Environment and the Treasury/Finance department.

In PROMOTioN's interviews with TSOs and with other OWF developers, all quote the number of ministries that need to be satisfied as a complexity. For even relatively simple assets like Interconnectors, between two countries, it can be that 5-6 ministries sit at the table for negotiations.

AGENCY FOR THE COOPERATION OF ENERGY REGULATORS

ACER[41] is a European Union Agency which was created by the Third Energy Package to further progress the completion of the internal energy market both for electricity and natural gas. ACER was officially launched in March 2011, and has its headquarters in Ljubljana, Slovenia.

[41] https://acer.europa.eu/en/The_agency/Pages/default.aspx

ACER is an independent organisation which fosters cooperation among European energy regulators. ACER ensures that market integration and the harmonisation of regulatory frameworks are achieved within the framework of the EU's energy policy objectives.

TRANSMISSION SYSTEM OWNERS/OPERATORS

A TSO is an entity entrusted with transporting energy in the form of natural gas or electrical power on a national or regional level, using fixed infrastructure. The term is defined by the European Commission. The certification procedure for Transmission System Operators is listed in Article 10 of the Electricity and Gas Directives of 2009.

The TSOs are core stakeholders in the offshore grid. They determine in practice the design, build and operation of the offshore grids. What is built and how it is built is a dialog between OWF developers, the Government, the Regulator and the TSO. The TSOs are also influencers in the development and application of technologies, management of the supply chain, and management of maintenance and repair.

Due to the cost of establishing a transmission infrastructure, such as main power lines or gas main lines and associated connection points, a TSO is usually a natural monopoly, and as such its income is often subjected to regulations and/or incentives. The map in Figure 20 below summarises the TSOs in the North Seas region.

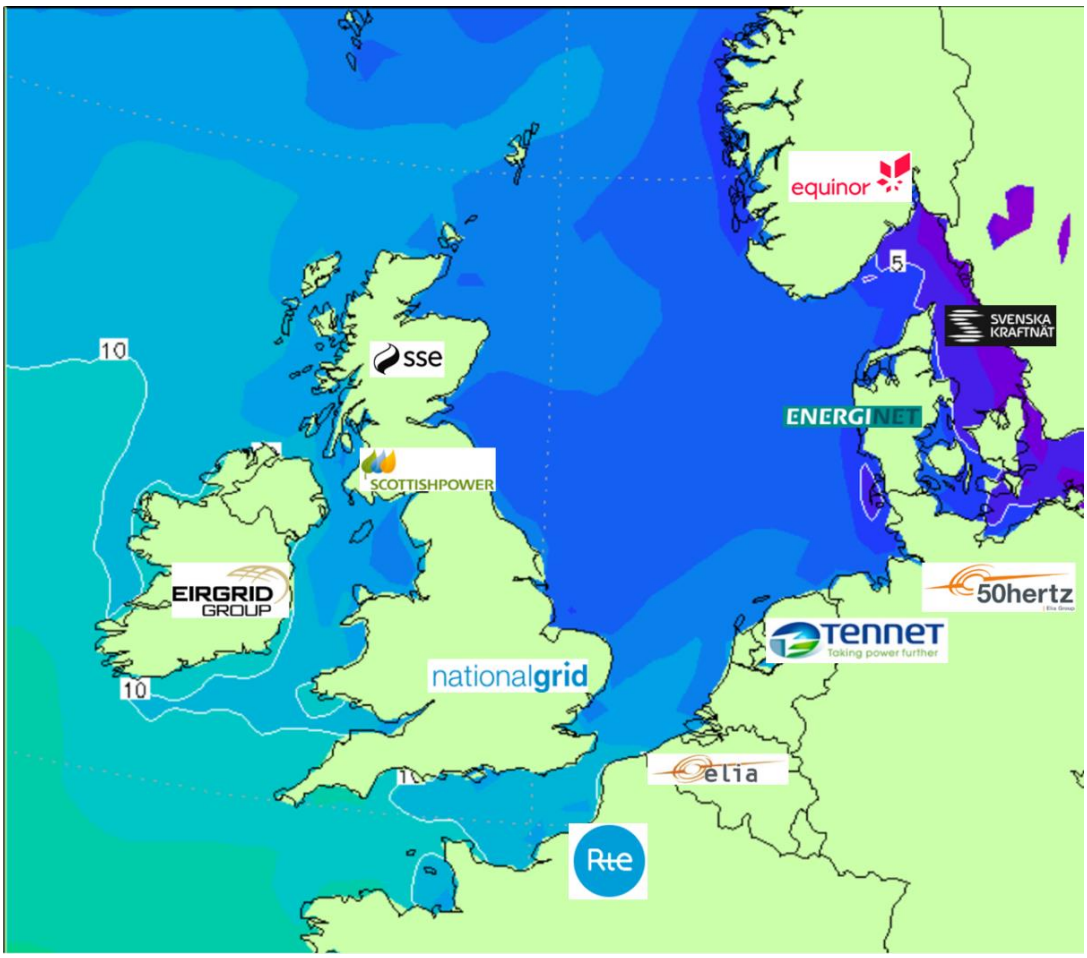


Figure 20 - Map of North Seas TSOs

- The Belgian TSO is Elia TSO. This is a listed company, albeit with major shareholdings by the Regional Governments of Belgium. Elia is strongly regulated by the Belgian Federal Regulator. Elia is also the owner of 50 Herz the German TSO.

- France has a state owned TSO, RTE.
- The Netherlands has a state owned corporatised TSO, TenneT TSO. TenneT is the owner of TenneT Germany.
- In the UK, there are three transmission owners: National Grid Electricity Transmission (NGET) in England and Wales, SHE Transmission Limited (part of SSE Networks) in Northern Scotland and Scottish Power (SP) Transmission in Southern Scotland. National Grid Electricity System Operator (NGESO) operates the transmission network across Great Britain (Northern Ireland is managed as part of the Irish Network by EirGrid). However, if the transmission owners want to bid to own offshore transmission assets they have to do so through special purpose vehicles. Offshore assets are owned by OFTOs see section
- On the island of Ireland, the transmission network is owned by ESB in the Republic of Ireland and Northern Ireland Electricity (a subsidiary of ESB) in Northern Ireland. The system operator is the EirGrid in the Republic of Ireland and SONI in Northern Ireland. Both are part of the EirGrid group.
- Denmark has a state-owned TSO, Energinet. There is talk of opening the offshore market to OWFs to construct their own infrastructure.
- Germany has no single national monopoly national TSO. Instead there are 4 regional TSOs: TenneT Germany; 50 Hertz (Elia); Amprion and Transnet BW. The TSOs managing coastal areas are TenneT (North Sea and Baltic Sea West) and 50 Herz (Baltic Sea East). These are both in turn subsidiaries of other European TSOs.
- Sweden has Svenska Kraftnät which is state owned TSO.
- Norway has a national TSO, Statnett as in other European mainland countries. There is currently only a nascent offshore wind generation industry. This is being led by Equinor the state oil company, who are also investigating interconnectivity options. However, because of ample mechanical storage options in Norway a number of Interconnectors have been built between Norway and other European countries.

TenneT (The Netherlands & Germany); RTE (France), Energinet (Denmark), Eirgrid (Ireland); SHE Transmission (UK), SvK (Sweden) are all members of the PROMOTioN consortium.

OFFSHORE TRANSMISSION OWNER

OFTOs operate and maintain specific assets for the evacuation of electricity from UK OWFs to shore. The OFTOs are often special purpose vehicles set up specifically to own and maintain transmission assets between a specific OWF and the onshore grid in the UK. To date OFTOs have consisted of multiple combinations of a small number of financial and strategic players. These consist of both strategic investors, such as Mitsubishi and Balfour Beatty, and of financial infrastructure investment funds, such as Blue Transmission, Macquarie and DIF. To date these have formed different permutations to qualify for Government tenders.

OFTOs are remunerated a regulated income based on agreements made prior to and during purchase of the asset, which to date, has always been built by the OWF generator. The participants in the current OFTOs represent a focused group of financial investors that have deep understanding of the industry.

At present there are no OFTOs represented in the PROMOTioN consortium. However, Ørsted is a partner and has experience in the development of UK offshore wind.

WIND FARM DEVELOPERS

Offshore Wind Farm Developers are key stakeholders. Their interest in a Meshed offshore grid is linked to the cost of evacuation and the portion allocated to the OWF. Offshore Wind farm developers are most often consortia of companies brought together to tender, plan, build and operate offshore wind farms.

The responsibilities of OWF developers vary from country to country in terms of when they become involved in site development and how much of the transmission connection they build. The OWFs are remunerated via regulatory schemes which differ from country to country.

Within the PROMOTioN consortium we have Ørsted and Equinor as entities building OWFs. Siemens and Mitsubishi also invest, but largely as technology partners.

INVESTORS

The offshore transmission network will require significant investment from private banks, sovereign wealth funds, state-owned banks and international funding organisations such as the European Investment Bank (EIB). Banks and other investors are increasingly interested in the sustainability impacts of their investments, with several looking to divest from fossil fuels and into more sustainable forms of energy.

MANUFACTURERS AND CONTRACTORS

Manufacturers are stakeholders in that they design and supply the offshore infrastructure. Their interests are in volume of different technologies required, and the standards and interoperability that will be needed for equipment to be connected. For current radial connections many projects have been turnkey or manufacturer specific. As the grid develops and becomes more integrated, the need for interoperability increases. Contractors and fabricators also need to understand volumes and lead times for equipment. Also much of the offshore construction requires specialised ships/cranes/equipment, which may today have limited availability.

Within PROMOTioN, in other programmes, such as Migrate and Best Paths, different technology aspects have been targeted for advancement. A number of manufacturers have participated in these programmes and shared knowledge to help advance the industrialisation of HVDC grid elements.

ABB, Mitsubishi, Siemens, SciBreak, Prysmian and GE Grid Solutions are manufacturers participating in PROMOTioN. FGH, a partner, is an engineering service company. The industry lobby group T&D

TESTING, INSPECTION AND CERTIFICATION AGENCIES

Testing, inspection and certification agencies are stakeholders as all installations will need appropriate approval. We should be aware that the HVDC industry in its nascence is immature. The TICs will probably be required to train and develop new staff for the role. They are therefore interested in being able to plan the development of tools and standards to monitor equipment. Their interests are in technology, planning and maintenance schedules, standardisation and interoperability of equipment.

TIC is integrated into all parts of the process of building the grid infrastructure. Accredited TIC firms are required to qualify all components used in and systems used for transmission and evacuation of energy. As such they operate as support for TSOs, manufacturers, and operators of grids and installations offshore.

DNVGL leads the PROMOTioN project. Deutsche WindGuard is a German TIC focused on Wind energy and participates in PROMOTioN.

NON GOVERNMENTAL ORGANSIATION (NGO)

NGOs seek a balance in the use of and protection of the North Sea. Their interests vary, but often include the planning of space usage in the marine environment and the impact of the equipment at installation and during operation of the equipment on the environment, in particular birds and marine life, pollution and visual perspectives.

Stiftung Offshore Wind has positioned itself as a non-partisan promoter of wind energy and wind energy research. While its funding members are mostly from the offshore wind energy sector, its primary goals are to protect the environment and ensure sustainable offshore development of wind generation. SOW is a consortium member.

INTERCONNECTOR OWNERS

There are a number of interconnectors built between European countries. At present the amount of international capacity is perceived as insufficient to provide an interactive European Market. As such, the EC is proposing increase and various studies for new interconnectors are being considered. The construction of more grid interconnectivity will eventually impact existing interconnector operations and existing market players who may see changes in their business models necessary for survival. This is a potential conflict of interests for owners.

There are a number of semi-commercial and linked companies that form either a part of an offshore grid, e.g. BritNed (interconnector between the UK and the Netherlands, owned by TenneT and the National Grid). This company owns assets that form an integral function within a European grid. They are interested in Interconnection targets and goals, development of the grid, market models. All of which may impact the commercial business model of the company

TenneT is part owner of BritNed and a participant in PROMOTioN.

OTHER RELATED PARTIES

Lobby groups related to fishing, transport, sport, etc. will be interested and require consultation in the construction and planning of a grid. They are mostly interested in spatial planning, which was examined in WP7 of PROMOTioN.

Educational and research institutions are interested in the development and application of the infrastructure. In particular, PROMOTioN has attracted active participation in technical research around HVDC technology. Also a number of universities have participated in the studies around Legal & Regulatory issues, Economic issues, Market modelling.

The Universities of Strathclyde, Aberdeen, Katholieke Universiteit Leuven, RWTH-Aachen, the Supergrid Institute in Lyon, TU Delft, Rijksuniversiteit Groningen, KTH (Sweden), Universitat Politecnica Valencia, The European University Institute Florence, and DTU all are partners in the PROMOTioN project. Carbon Trust is a not-for-profit energy and environment consultancy and a member of the PROMOTioN consortium.

V. APPENDIX – OFFSHORE WIND MARKET STRUCTURES

Report by TU Delft

INTRODUCTION

When a large number of wind parks are developed in the North Sea, a choice will need to be made as to how to remunerate them. When wind parks become connected to more than one country, it is not given that the best choice is to pay them the electricity market prices of the countries in whose EEZ they are located. Power that is generated by offshore wind parks may not always flow to the countries in whose zone they are located. From the perspective of the European integrated electricity market, the objective should be to generate renewable energy in the most economically efficient manner and to transport it to where the added value is highest, regardless of national policy targets and boundaries[42]. Also, within PROMOTioN, we anticipate that there will be an increased meshing of grids which may result in more obvious alternative routing than direct transport from the economic zone in which the OWF is located to the shore of that country. From these perspectives, we study different pricing rules for offshore wind parks in a meshed grid.

We develop a range of pricing options that represent fundamentally different approaches to the problem. We analyse them in a series of stylised, numerical example cases, all based on the same configuration of offshore wind parks and a network that is connected to several countries. This approach helps to ensure that the analysis is rigorous, while the numerical results are relatively easy to reproduce and therefore more transparent than a more realistic model would be. We compare the performance of the different pricing systems – market designs – with respect to economic efficiency and welfare effects.

A difficult issue is the question of financial support for wind parks, assuming that the countries who pay for the support will also want to receive the benefits of the generated wind energy. While the design of support instruments is not the topic of our work, inevitably there is a relation between the market design and the revenues of the wind parks, which influences the need for additional revenue to recover capital cost. Another issue to be considered is to what extent the offshore wind market design is suitable for innovations such as local storage and power conversion facilities such as for hydrogen production. We will discuss these issues in Chapter 0, after the main analysis has been completed. In addition, factors such as social acceptability (fairness), feasibility, transaction costs and transparency will play a role in practice, but we will not review these here, but here we will focus on a market design that is economically efficient and feasible in the European legal context.

The remainder of this document is organised as follows: Section 2 describes the theory and assumptions that underlie our analysis. In Section 3 we develop a number of options for pricing offshore wind energy. In Section 4, simple numerical examples are used to compare these options. Section 0 provides a comparison and an analysis, which also touches upon investment, renewable energy policy and the relation with other energy carriers. Section 0 reviews the juridical implications of the analysis and 0 sums up the conclusions of the analysis.

[42] The Fourth report on the State of the Energy Union (Brussels, 9.4.2019, COM(21019) 175 final) states these objectives in nearly the same words. The Renewable Energy Directive also stresses the importance of a well-functioning internal energy market for the economically efficient integration of renewable energy (DIRECTIVE (EU) 2018/2001 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 11 December 2018 on the promotion of the use of energy from renewable sources).

ASSUMPTIONS

In this section, we present some simplifying assumptions that we made in order to be able to focus our analysis on the essence. Economic efficiency in electricity generation is achieved when the cost of generation dispatch is minimised within the given network constraints, given a certain demand. In Europe, this outcome is approximated by minimizing the cost of generation within price zones. In our examples, we assume that the demand for electricity is price-inelastic, but this will not influence the analysis of market designs in this study. We may assume that the price elasticity of electricity demand will increase in the future, which should reduce price volatility, but on the other hand the increase in solar and wind generation may increase price volatility. However, the degree of price volatility does not affect our basic analysis of the economic efficiency of different market designs, their impact upon congestion rent, generator and consumer welfare, and their interaction with renewable energy policy instruments. The numerical examples in Section 0 only provide a qualitative insight into these effects, as they are not quantitatively representative in any respect. Their purpose is to provide easy insight into the different market designs, not to provide any kind of quantitative forecast.

The objective of economic efficiency is not difficult to assess, when it comes to the operation of offshore wind parks. As the variable cost of wind energy is low, economic efficiency is reached if the output from wind generators is maximised. The only exception is if the total volume of wind and solar power exceeds demand, there is insufficient storage capacity available and there is not sufficient network capacity to transmit the remaining wind energy to consumers in another area. Then, curtailment of wind (and/or solar) generation may be necessary. As a result, there is a simple rule of thumb for comparing different market designs with respect to economic efficiency: a market design that leads to a lower usage rate of wind power is less efficient than one with a higher volume.[43]

Electricity markets are currently organised on a zonal basis in Europe. The borders between the price zones largely are the same as country borders, although some countries have multiple zones and some zones extend across borders. The configuration of price zones impacts the operational decisions of generation companies and consumers, such as the dispatch of generation and the timing of flexible consumption, and potentially also their investment decisions. An electricity price zone is characterised by a single price for electricity at any moment, regardless of the occurrence of network congestion within the zone. There may be different prices, however, in markets with different time frames such as day-ahead, intra-day and balancing markets in a price zone. In our analysis, we make the simplifying assumption that there is a single market price. The reason is that the question that we address concerns the financial impact of the main governance choices, not the details of short-term trading. We will only consider two time steps, one with high and one with low wind generation, in order to make it easy to follow the analysis.

If there is sufficient cross-border network capacity to facilitate all the power flows that result from the market transactions, the prices in neighbouring zones may converge to the same price. If not, we consider the border to be congested. In most North Sea countries, congestion between price zones is handled through market splitting or market coupling, a form of implicit auctioning of available network capacity, while congestion within price zones is handled ex post, i.e. after day-ahead market clearing, through the redispatching of generation units by the TSO. Because this combination of congestion management methods does not make optimal use of available

[43] There is an exception to this rule of thumb, but this is out of the scope of this report. In some cases in which wind and thermal generators are part of the same market, it may be beneficial to ramp wind generators down more gradually in case of a decline in wind speed so as to provide more efficient but slower fossil-fuel generators time to ramp up, instead of relying on faster but more costly and more polluting quick-start units.

generation capacity, the congestion management is not optimal. As a result, the configuration of the borders of the price zones affects the levels of the zonal prices and of the revenues of the generators.

Because onshore network congestion is not the subject of this study, we assume in our calculations, that it is handled optimally. One should keep in mind, however, that if the meshed offshore grid provides a parallel route to a congested onshore route between a low-priced and a high-priced market zone, there will be interactions between the flows in the meshed offshore grid and onshore and therefore also economic impacts. If onshore network congestion is handled less efficiently, this may cause higher flows through the meshed offshore grid. The positive side of the coin is that by providing additional network connections, not only between member states but also within them, the meshed offshore grid increases the robustness and resilience of the onshore grid.

Because the offshore network is a direct current system, we assume that the system operator can control the power flows within the meshed offshore grid. Finally, we assume perfect competition in the entire system, which implies the absence of market power. This means that market prices are expected to be equal to the marginal cost of generation. (In case of limited power supply, the price could also be determined by the willingness to pay of demand, including storage facilities, but that is out of the scope, as mentioned above.)

To sum up, we make the following assumptions in our analysis:

- We consider two separate moments in time: one in which the wind turbines generate at maximum capacity, and one at which they generate at half capacity.
- The variable operational costs of wind parks are assumed to be zero.
- The technology used for the transmission of electricity enables control over the power flows.
- There is no congestion within the onshore price zones in our examples.
- Congestion between price zones is handled through a form of auctioning.
- There is no abuse of market power, i.e. no strategic behaviour.

In summary, given the above assumptions, the short-term economic efficiency (i.e. dispatch efficiency) of the meshed offshore grid is maximised if the dispatch of wind energy is maximised, given demand and grid constraints. We will review a number of market design options, all of which meet the criterion of dispatch efficiency. The discerning criteria therefore will be related to the welfare effects: what is the income distribution between the offshore wind generators, the TSOs, the consumers and the governments that are involved? Our examples are developed to illuminate these welfare distribution aspects.

PRICING OPTIONS FOR OFFSHORE WIND ENERGY

We identified four different principles for pricing electricity that is generated by offshore wind farms. These three options are based on earlier work on the topic, such as the North Seas Countries' Offshore Grid Initiative (2012) study of market arrangements for offshore wind and on the application of onshore market design.

- **Option 1: national price zones.** The national price zones are extended into the North Sea in accordance with the EEZs of the North Sea countries (Figure 21). This means that wind parks receive the electricity price of onshore price zone in which they are located.[44] This option is the status quo.
- **Option 2: a single offshore price zone.** A new price zone is created at sea. This encompasses all wind parks that are connected to the meshed offshore grid on the North Sea. The idea behind this option is that when the meshed offshore grid becomes more developed, the national prices and the zonal configuration based on the countries' exclusive economic zones become arbitrary. A single offshore zone could be a simple solution.

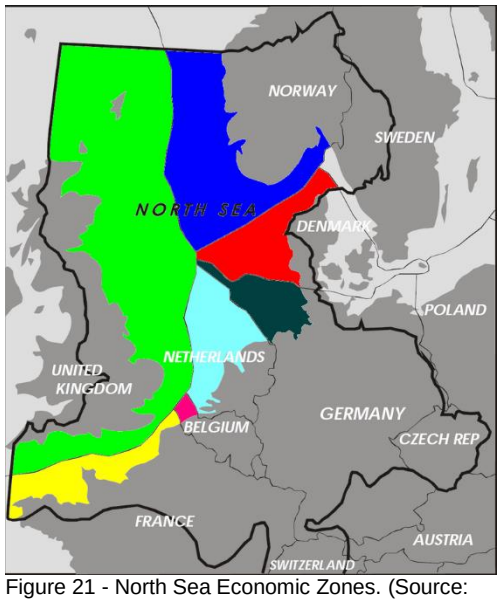


Figure 21 - North Sea Economic Zones. (Source: https://en.wikipedia.org/wiki/File:North_sea_eez.PNG)

- **Option 3: small price zones.** By defining price zones with the size of individual wind parks or small clusters of parks, the prices will reflect the local marginal cost of generation. This will avoid some of the key disadvantages of the earlier options.

NUMERICAL EXAMPLES

We will now introduce the numerical example which we will use to demonstrate the above four sets of market rules. The example is not intended to be realistic, but instead to show the key characteristics of the different options while being simple enough to be able to reproduce the quantitative results manually. Our example setup has three Countries A, B and C, each of which has its own price zone, in order to allow for the possibility of parallel flows. Firstly, there is a wind park located between countries A and C that is connected to both, as in Figure 22. If it produces a full capacity, its output needs to be split between the two countries.

[44] This rule is not unambiguous in case countries have multiple price zones, as in case of Country A. We will disregard this issue for now in order to explore whether this pricing principle is worth pursuing at all.

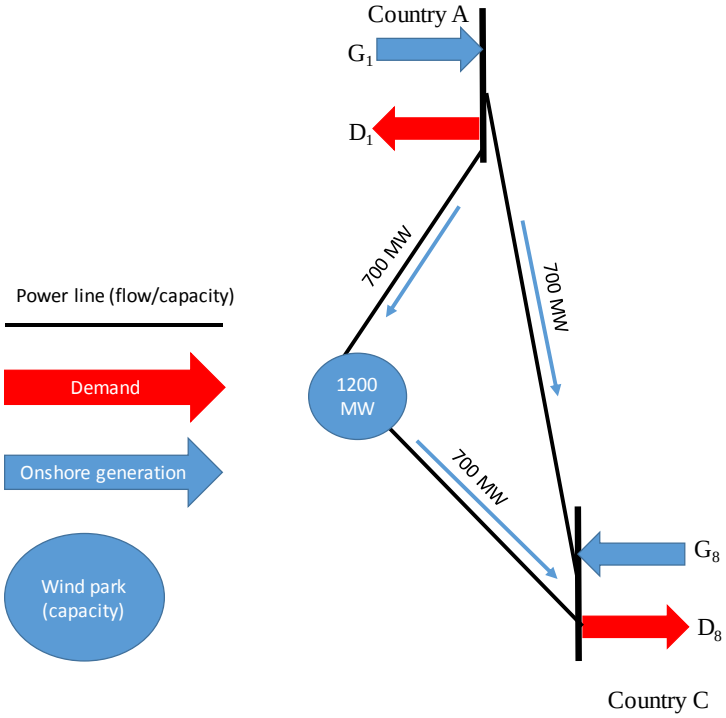


Figure 22 - Example set-up: wind park connected to two countries

The second part of the example consists of a string of wind parks exists in parallel to an interconnector between Countries A and B (Figure 23). The purpose of this part of the example is to analyse the impact of network congestion within a meshed offshore grid. While the actual North Sea meshed offshore grid will not look like this, the example is designed to show the impacts of the various pricing rules.

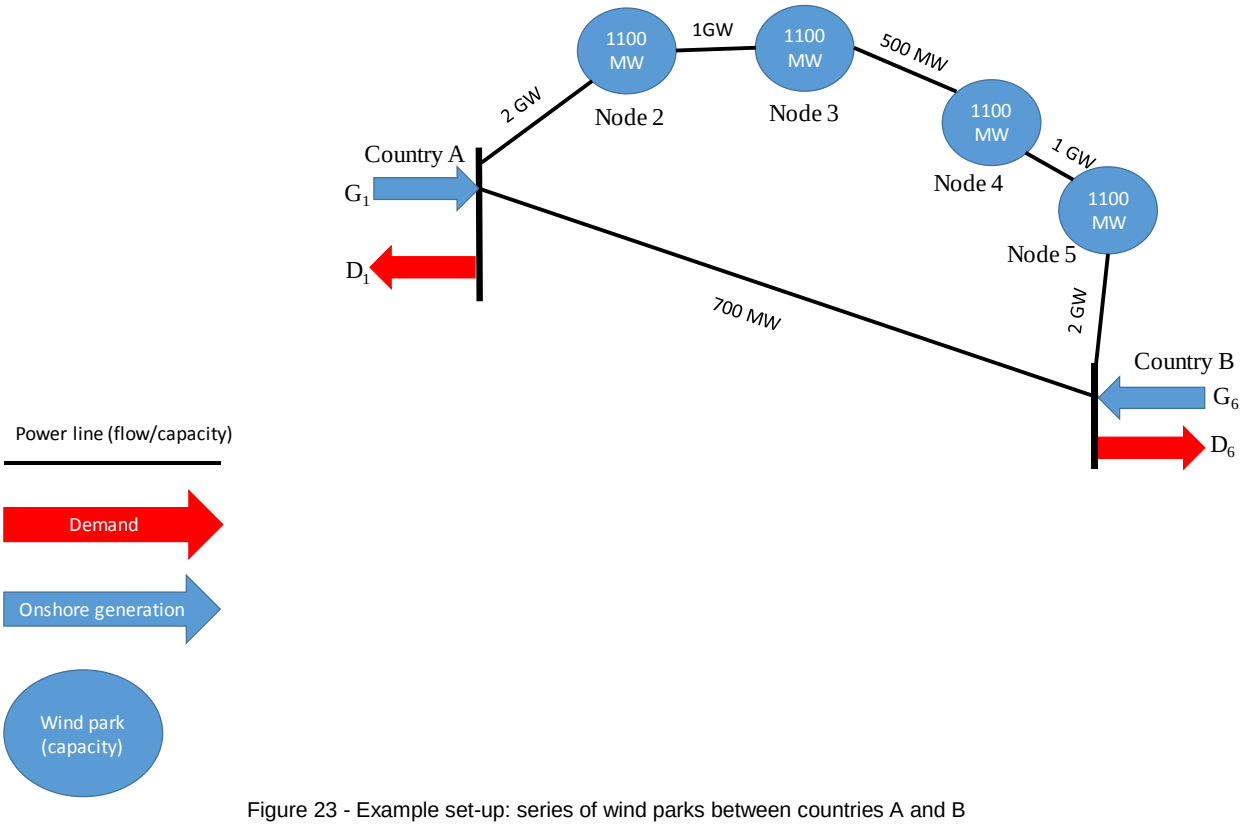


Figure 23 - Example set-up: series of wind parks between countries A and B

Combining Figure 22 and Figure 23, we arrive at the system that is depicted in Figure 24, which consists of eight nodes (Country C, Country B, Country A and five wind parks) that are connected to each other by transmission lines as shown in Figure 24. We label all nodes in our examples, because they are grouped differently in the different market designs. In Figure 24, the capacities of the wind parks (blue balls) indicate their maximum generation capacity. In the following figures, we will indicate the actual generation (which may be curtailed) as well as the maximum generation capacity given the current wind speed as X/X MW. Note that the second value is not the installed generation capacity, but the potential output under current wind conditions. The difference between the two figures is the capacity that is curtailed.

Similarly, Figure 24 shows the maximum line capacities, while in the following graphs we will show the actual flows versus the capacity, again as X/X MW. Because power can flow in both directions, we apply the convention that a flow in the direction of the arrow (which is from a node with a lower number to a node with a higher number) is indicated as positive and an opposite flow as negative.

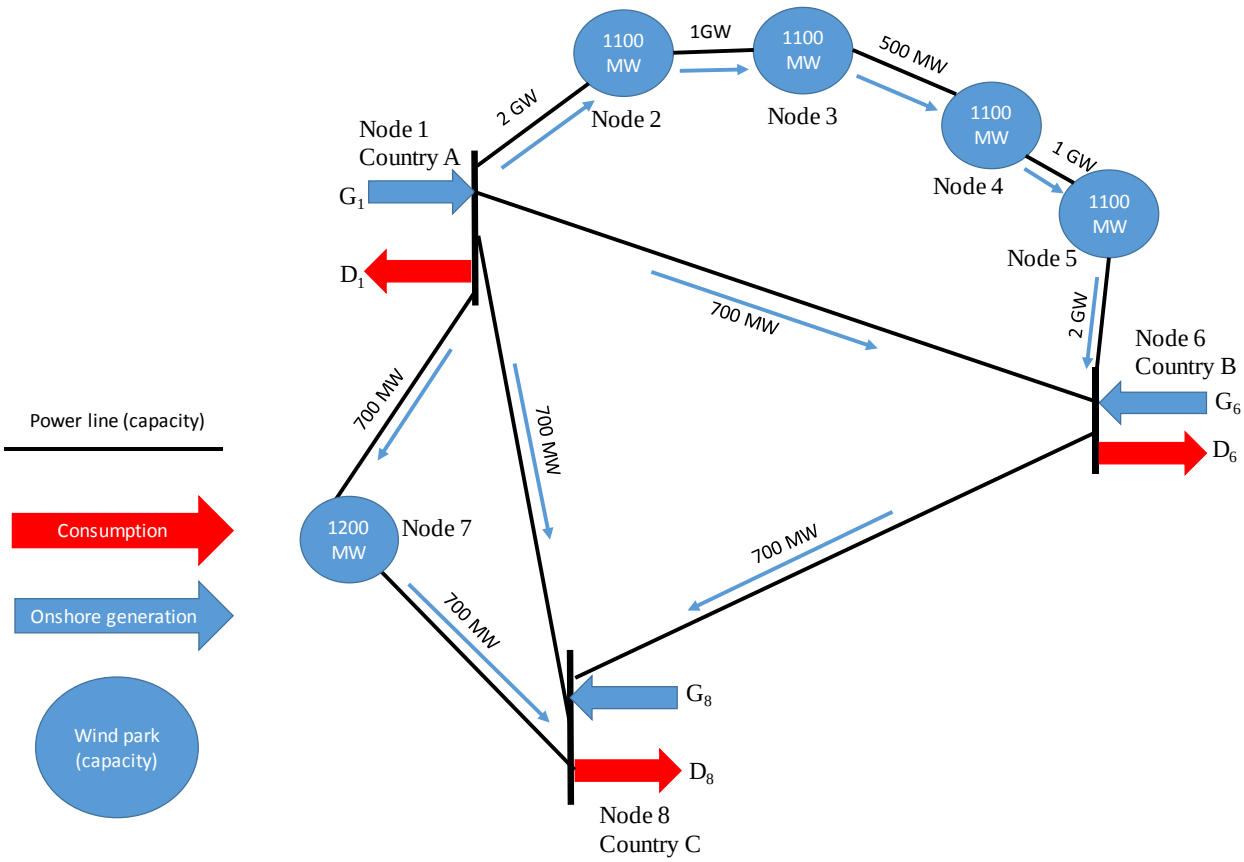


Figure 24 - Example set-up

Please note that the generation and line capacities are the same in all market designs, as are the costs of generation and the demand volumes. The only differences are in the configurations of the price zones. The marginal value of wind generation is equal to the market price at which it is sold, as we assume that the wind energy replaces generation with a marginal cost equal to this price.

We developed a simple optimization model to carry out this analysis. The model minimises the cost of generation, subject to the constraint that all demand must be met and network flows may not exceed line capacities. As the variable cost of wind generation is always lower than the market prices in our examples, the output of the wind parks is always maximised in the model and only constrained by the capacity of the network.

In our example, the price in Country A is always the lowest, the price in Country B is higher and in Country C the highest. The market prices are the same in all our market designs, because as long as the dispatch is the same and congestion is managed efficiently, the supply and demand situations are the same in all the countries and therefore their prices are the same. The difference lies in the remuneration of the wind parks.

Within PROMOTioN, the grids are designed explicitly to evacuate the generated energy. In this sub-project and for illustration, we dimensioned the maximum capacity of the wind parks higher than the available network capacity. Consequently, when the wind parks produce at their maximum rate, the output of the northern four parks (Nodes 2-5) needs to be limited to 1000 MW per park/node on average. The reason for this over dimensioning is the intuition that the average cost per unit of electricity produced from the meshed offshore grid is minimised if the wind parks are over dimensioned to some degree because it leads to a higher utilization rate of the network. However, in our examples, the capacities of the wind parks and network elements have not been optimised, so the amount by which our wind parks are over dimensioned is arbitrary. We provide these examples to demonstrate the workings of different market designs but do not present a likely configuration of a real meshed offshore grid.

OPTION 1: NATIONAL PRICE ZONES

This market design assumes that the national bidding zones are extended to include the wind parks in the respective countries' Exclusive Economic Zones in the North Sea. Figure 25 presents the situation in the case that the wind parks produce at their maximum capacity of 1100 MW. From Nodes 2 and 3 the power flows to Country A (Node 1), hence the flows on these lines are indicated as negative. Line 1-2 is congested (in the direction of Node 2 to Node 1/Country A, hence the used capacity is indicated as negative). This means that wind park 3 needs to be curtailed: its output is limited to 900 MW, versus a maximum of 1100 MW. Different solutions are possible, e.g. curtailment in Node 2 and less curtailment in Node 3.

If generation needs to be curtailed, this raises two questions: which parks should be curtailed and should they be compensated? If the wind parks have exactly the same cost, there is no economic reason for preferring one solution over the other. However, if energy losses in transmission and variable operating costs, such as wear and tear of the wind turbines, are not ignored, the least-cost solution may be to curtail only the furthest generator, namely the one in Node 3, unless this park has significantly lower variable costs. The same is true for the wind parks in Nodes 4 and 5: the park furthest from demand is curtailed in our example, but a different rule could be applied. It is possible to share the curtailment more evenly, however, e.g. by curtailing all four wind parks in Nodes 2-5 by 100 MW each. This would increase network losses, but lead to a more even distribution of revenues among the wind park operators. This leads to the question of whether and how to compensate for curtailment. If the wind park developers overplanted, they should carry the risk of curtailment, but if curtailment results from the combined volume of wind generation relative to the total network capacity, there may be an argument for the network operator to compensate them, in this case by paying them the market price of their zone for the electricity that they did not generate.

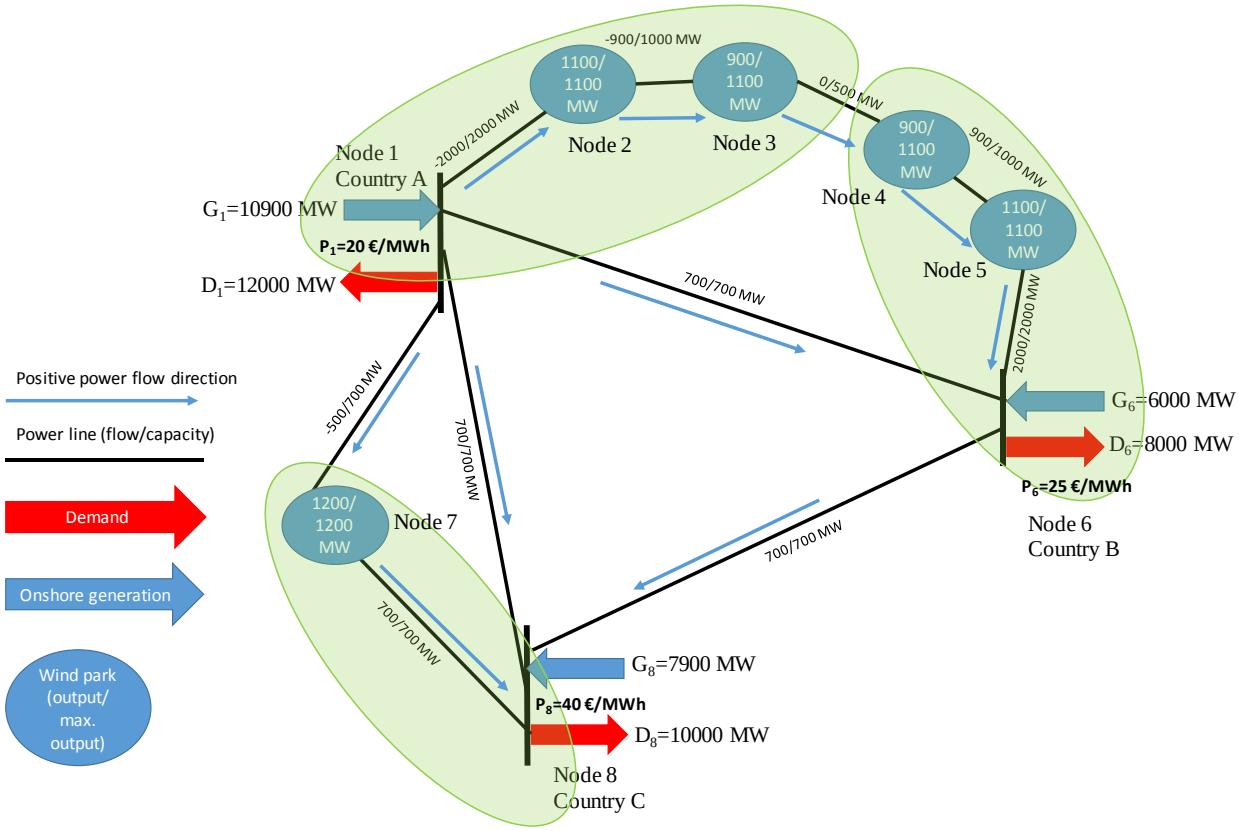


Figure 25 - Wind parks are part of national price zones, high wind

Now we will return to the power flows in our example. As the market price in Country C is highest, the network flows are directed towards this country as much as possible. Flows also go to Country B, as this has the second highest price. The produced wind energy only flows to Country A to the extent that there is not enough network capacity to the higher-priced countries. Therefore, 700 MW of the output of the wind park in Node 7 flows to Country C (Node 8), which is the maximum capacity of Line 7-8. The remaining 500 MW flows via the other connection of Node 7 to Country A (Node 1).

Despite the rule that wind parks bid into their price zones, efficient congestion management will result in the flows as depicted in Figure 25. These are the economically optimal flows; they are the same for all market designs. For instance, because Line 5-6 is congested, the wind parks in Nodes 2 and 3 cannot supply directly to Country B. Instead, their power flows to Country A, but Line 1-6 (the interconnector between Countries A and B) is fully used in the direction of Country B, so the net result is still that the maximum possible amount of power flows to Country B. This is socially optimal, as the higher price in Country B means that the wind energy has a higher benefit in terms of avoided cost of generation. However, for the wind parks in Nodes 2 and 3, this means that they receive the lower price of Country A, even though part of their output may be sold to the higher priced market of Country B.

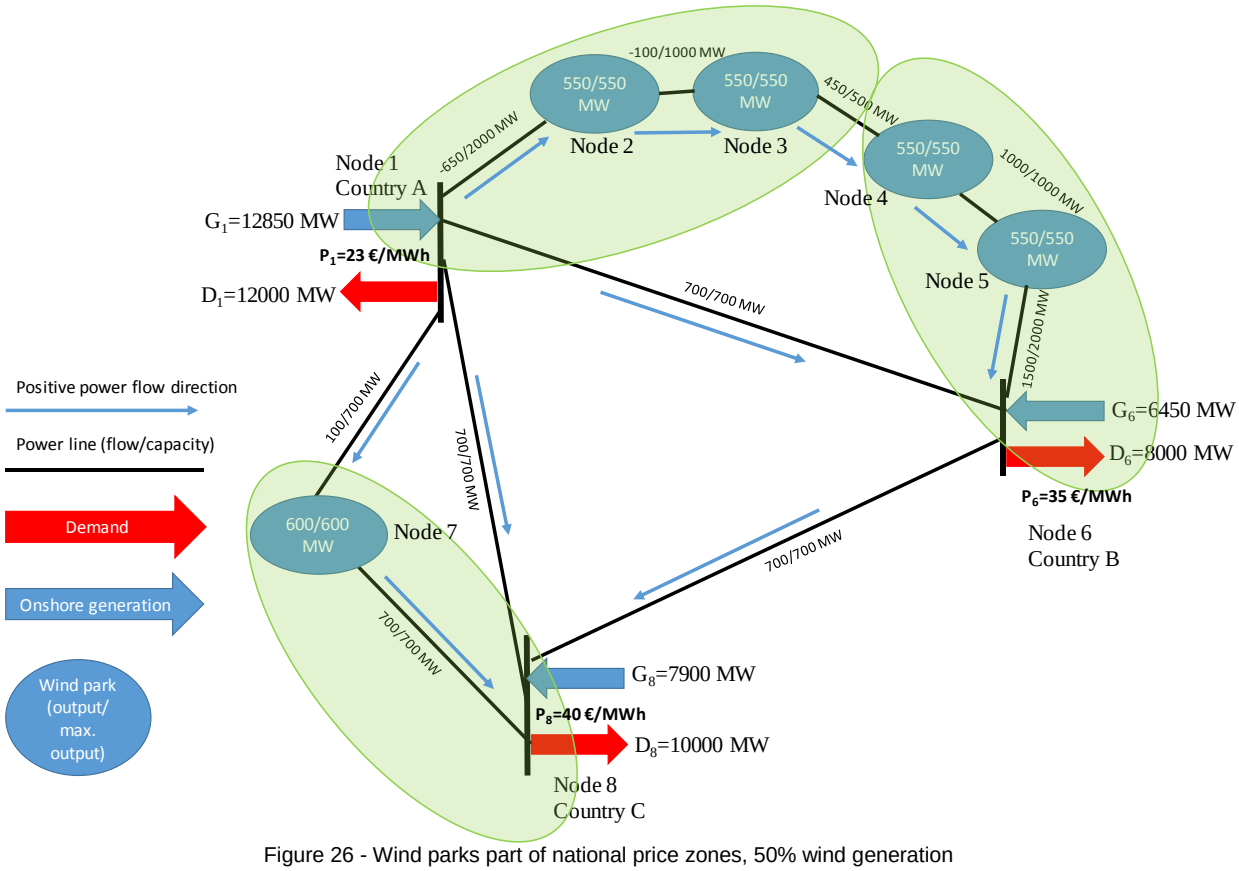


Figure 26 - Wind parks part of national price zones, 50% wind generation

The wind park in Node 7, which lies in the zone of Country C, also exports to Country A in this case. This is less intuitive, as Country A has a lower market price. However, only a little more than half the maximum output of this park can be transmitted in each direction, so if there is much wind, its output will always need to be split. In this case, the wind park benefits from the zonal configuration, but the result is a counterintuitive flow from the high-priced Node 7 to the lower priced Country A. Someone, presumably a network operator, is paying the wind park in Node 7 a price of 40 €/MWh for 500 MW and is selling this in Country A for a price of 23 €/MWh! From a welfare maximization point of view this is rational, as the alternative would have been to curtail the wind park in Node 8 and increase the more expensive generation in Country A. However, reaching this welfare-optimal outcome in this market design requires trading from a high to a low price zone, which would require some kind of financial input. The beneficiary of this is the wind park in the high price zone, which receives the high price for its full output, even if not all its output can be delivered to Country C. (As an aside: in our example, the cost of buying power in Node 7 and selling it in Country A is offset by the congestion rents from Line 1-8, buying in Country A and selling in Country C. However, if no party is willing to pay the wind park in Node 7 for exporting to Country A, the alternative is that the wind park reduces its output to the volume that it can sell to Country C, namely 700 MW. This reduces overall welfare, as wind generation is unnecessarily curtailed.)

Figure 26 shows the same scenario in a case with less wind, when the wind parks produce at 50% of their maximum capacity. (We assume that the wind force is the same throughout the system.) Now, the 'windconnector' to which the park in Node 7 is connected is used to export some power from Country A to Country C, as the wind park's output is less than the cable capacity. As a consequence, Line 7-8 is still congested.

The park in Node 3 mainly produces for Country B now, but receives the lower price of Country A because of its location. The market prices in Country A and Country B are slightly higher than in the case of full wind capacity,

while the price in Country C remains the same. The reason for the higher prices is that more onshore capacity needs to be used, so more expensive generators need to be dispatched now. The price increases in our example are rather small due to the relatively small volume of wind energy in our example in comparison to the onshore markets. In reality, the impact on wholesale prices will be much more significant if the volume of wind energy at sea grows as is foreseen in this project.

In Table 9, the wind park revenues are shown; the wind parks are indicated with a W and their nodal number.

Table 10 shows the congestion rents per power cable. The flows on the cables are indicated with an F and the numbers of the nodes which they connect. (Remember that the flow direction is considered positive if it is from a node with a lower number to one with a higher number.) $P_{low\ node}$ is the electricity price in the node with the lower number, $P_{high\ node}$ the price in the node with the higher number. The negative congestion rent in the high wind scenario result from the flow between the wind park in Node 8, which has the price of Country C, and Country A.

Table 11 shows the wind park revenues in the low-wind scenario, which are a little more than half because, although the wind power is exactly half, there is no wind curtailment and the market prices are slightly higher. Congestion rent is significantly higher in this case, as can be seen in Table 12, because the capacity of the meshed offshore grid that is not used for evacuating wind power is used as interconnection capacity.

Table 9 - Wind park revenues, national price zones, high wind

	OUTPUT	PRICE	REVENUE
	MW	€/MWh	€/h
W2	1100	20	22 000
W3	900	20	18 000
W4	900	25	22 500
W5	1100	25	27 500
W8	1200	40	48 000
			138 000

Table 10 - Line flows and congestion rent, national price zones, high wind

LINE	FLOW	$P_{LOW\ NODE}$	$P_{HIGH\ NODE}$	CONGESTION RENT
	MW	€/MWh	€/MWh	€/h
F12	-2000	20	20	0
F23	-900	20	20	0
F34	0	20	25	0
F45	900	25	25	0
F56	2000	25	25	0
F17	-500	20	40	-10 000
F78	-700	40	40	0
F16	700	20	25	3 500
F67	700	25	40	10 500
F18	700	20	40	14 000
				18 000

Table 11 - Wind park revenues, national price zones, low wind

	OUTPUT	PRICE	REVENUE
	MW	€/MWh	€/h
W2	550	23	12 650
W3	550	23	12 650
W4	550	35	19 250
W5	550	35	19 250
W7	600	40	24 000
			87 800

Table 12 - Line flows and congestion rent, national price zones, low wind

LINE	FLOW	$P_{LOW\ NODE}$	$P_{HIGH\ NODE}$	CONGESTION RENT
	MW	€/MWh	€/MWh	€/h
F12	-650	23	23	0
F23	-100	23	23	0
F34	450	23	35	5 400
F45	1 000	35	35	0
F56	1 550	35	35	0
F17	100	23	40	1 700
F78	700	40	40	0
F16	700	23	35	8 400
F68	700	35	40	3 500
F18	700	23	40	11 900
				30 900

OPTION 2: SINGLE OFFSHORE PRICE ZONE

In this market design, we assume that all wind parks are part of a single offshore price zone. The rationale is that if the extension of onshore price zones into the North Sea yields counter intuitive results such as negative congestion rents and different prices for neighbouring wind parks, a new offshore price zone may produce better outcomes. From a market point of view, the offshore wind price zone is unusual because there is no electricity demand, so there is no internal equilibrium between supply and demand. Therefore, the market price is determined by the demand for imports from this zone into the neighbouring price zones.

Commensurate with economic theory, we let the price in the offshore zone be determined by the marginal value of generation in this zone, which is the market price at which the last MWh of wind energy from the offshore price zone can be sold. Because power transmission to Countries C and B is constrained by the network, part of the wind power from the offshore zone needs to be sold in Country A. Therefore, the price in Country A is the marginal value of generation and this price becomes the price for the entire offshore zone. See Figure 27.

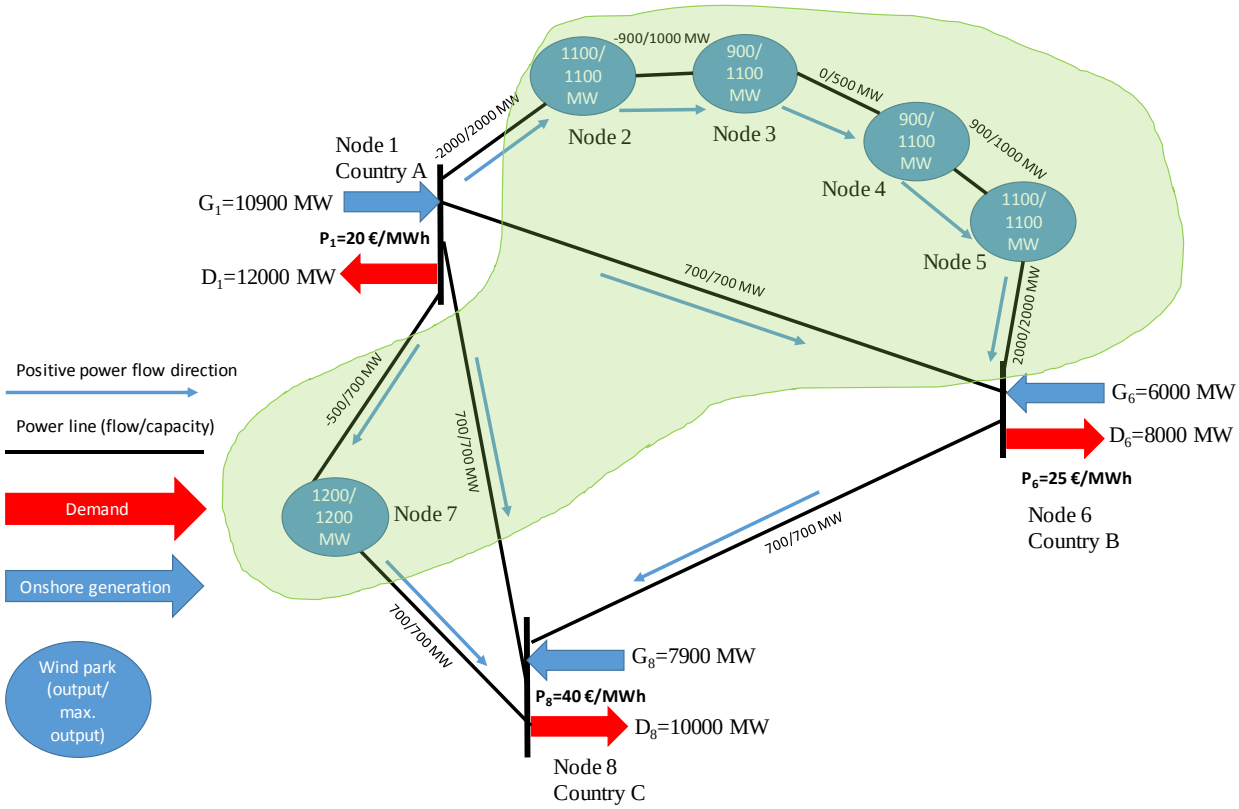


Figure 27 - A single offshore price zone, high wind

Again, there is a need for curtailing wind farms. As the physical conditions are the same in our examples, they need for curtailment is the same as well. Similar issues arise as in case of national price zones, namely which parks to curtail and whether to compensate them. As the market price for wind energy is likely lower in this market design, the cost of compensation will also be lower.

While this market design does not result in flows from high to low priced zones, the revenues of the offshore wind generators are lower than in the other market designs that we investigate. This would mean that financial support for offshore wind would need to be higher. As the market prices are still the same in the three countries, the difference in wind park revenue is captured by the network operators in the form of increased congestion rent.

Figure 28 shows that even when the wind parks produce at only 50% of their capacity, they still deliver some of their power to the cheapest price zone. (The flows are the same as in the National Price Zone model) As a result, the price in the offshore price zone is equal to the lowest connected market price, i.e. the price of Country A. How often the price would be this low in practice would depend on the share of wind at sea in the national markets and on the configuration of the meshed offshore grid, namely the degree to which the output could be directed towards the most expensive markets. Due to the lower supply of wind, the price in Country A is higher than in the high wind scenario, offsetting the lost sales volume from the offshore wind parks somewhat.

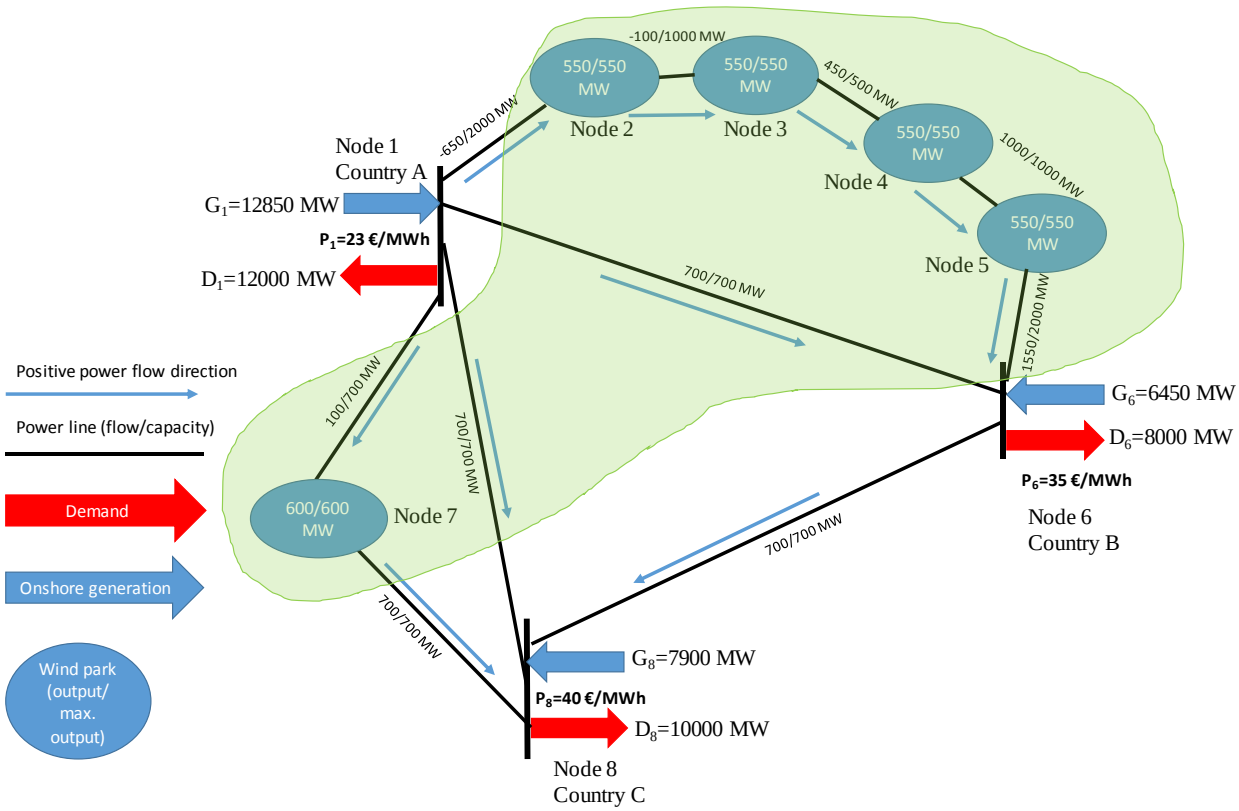


Figure 28 - A single offshore price zone, 50% wind capacity

Table 13 shows the offshore wind revenues in the high wind case and Table 15 in the low wind case. They are substantially lower than in the national price zone model. Table 14 and Table 16 show the corresponding congestion rents. The sum of wind park revenues and congestion rent is the same in all high-wind scenarios: the figure is 156,000 €/h in the high-wind scenario and 118,700 €/h in the low-wind scenario. This is equal to the consumer payments (price*consumption volume) minus the onshore generators' revenues (price*generation volume).

The lower revenues are inherent to this market design, as they are a consequence of the need to adjust the offshore price to the lowest-priced market to which electricity is delivered. A related disadvantage of this model is that wind parks that are serving high-priced markets receive less revenue than they could receive in a different market design, and may therefore argue for a different definition of the offshore price zone. The boundaries of this zone are indeed arbitrary, which brings us to the next market design, in which price zones are defined according to the network topology.

Table 13 - Wind park revenues, single offshore price zone, high wind

	OUTPUT	PRICE	REVENUE
	MW	€/MWh	€/h
W2	1100	20	22 000
W3	900	20	18 000
W4	900	20	18 000
W5	1100	20	22 000
W8	1200	20	24 000
			104 000

Table 14 - Line flows and congestion rent single offshore price zone, high wind

LINE	FLOW	$P_{LOW\ NODE}$	$P_{HIGH\ NODE}$	CONGESTION RENT
	MW	€/MWh	€/MWh	€/h
F12	-2000	20	20	0
F23	-1000	20	20	0
F34	0	20	20	0
F45	1000	20	20	0
F56	2000	20	25	10 000
F17	-500	20	20	0
F78	-700	40	20	14 000
F16	700	20	25	3 500
F67	700	25	40	10 500
F18	700	20	40	14 000
				52 000

Table 15 - Wind park revenues, single offshore price zone, low wind

	OUTPUT	PRICE	REVENUE
	MW	€/MWh	€/h
W2	550	23	12 650
W3	550	23	12 650
W4	550	23	12 650
W5	550	23	12 650
W8	600	23	13 800
			64 400

Table 16 - Line flows and congestion rent, single offshore price zone, low wind

LINE	FLOW	$P_{LOW\ NODE}$	$P_{HIGH\ NODE}$	CONGESTION RENT
	MW	€/MWh	€/MWh	€/h
F12	-650	23	23	0
F23	-100	23	23	0
F34	450	23	23	0
F45	1 000	23	23	0
F56	1 550	23	35	18 600
F17	100	23	23	0
F78	700	23	40	11 900
F16	700	23	35	8 400
F67	700	35	40	3 500
F18	700	23	40	11 900
				54 300

OPTION 3: SMALL PRICE ZONES

As the national price zones provide arbitrary prices to wind parks and may require subsidised flows to achieve economic efficiency and a single offshore price zone leads to lower overall revenues, we will now investigate the option of creating small price zones. This option is similar to nodal pricing (locational marginal pricing), which is considered to be a theoretically optimal way to determine power plant dispatch within network constraints (cf. Neuhoff et al., 2013). For this reason alone already it merits investigation. Nodal pricing market design, as it has been developed and implemented in the USA, involves more aspects than we will discuss here, such as energy balancing and ancillary services. As we wish our market design to be as compatible with current European markets, we propose an extension of the current zonal onshore market design, but with such small zones that some of the disadvantages of the above options are avoided. Refer to Figure 29.

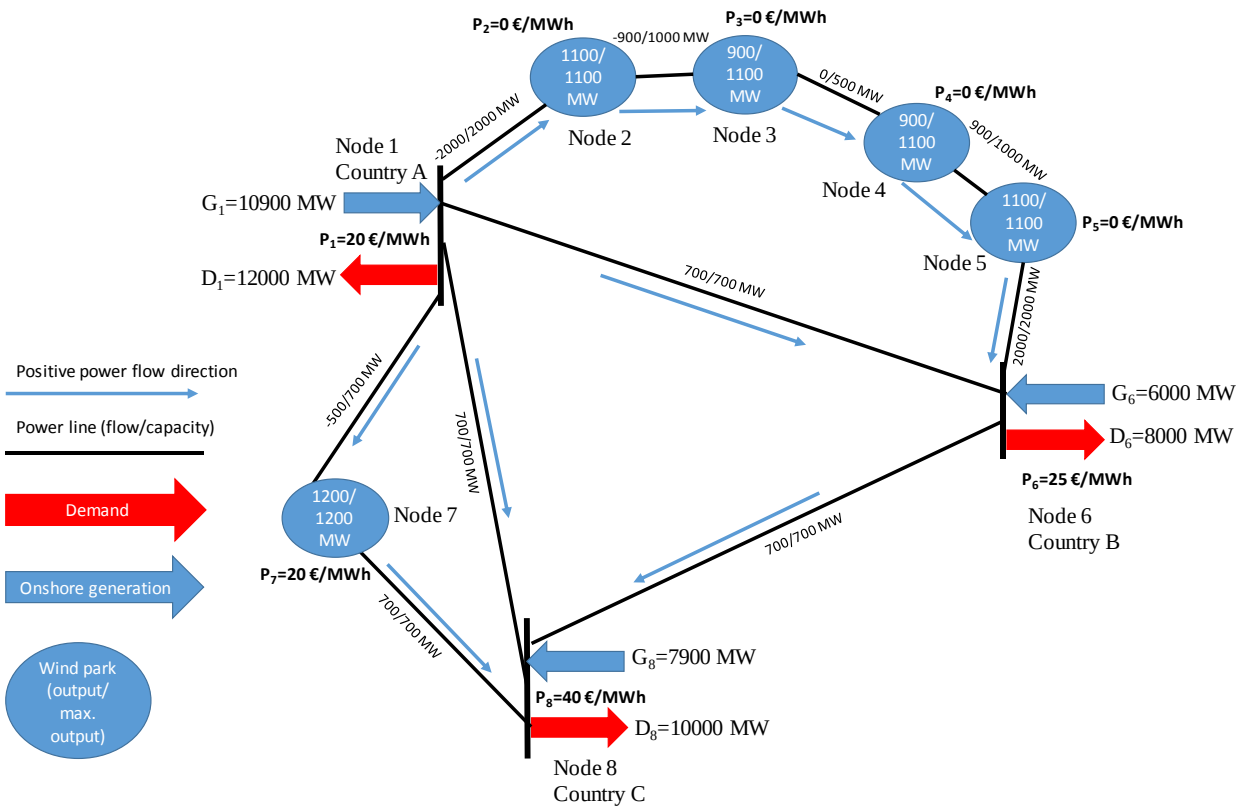


Figure 29 - Small price zones, high wind generation

Each price zone comprises one or a small number of wind parks without the potential for network congestion between them, for instance a single offshore station with connected wind parks. In our example, each price zone comprises only one node. The price in each zone is determined by supply and demand, i.e. by the marginal value of generation in that node to the system as a whole. This means that, in the absence of any local demand such as from storage or power-to-X, the price is equal to the price of the onshore market to which the wind park's power can be evaluated without congestion; if the wind park needs to be curtailed, the zonal price is equal to the marginal cost of generation, which is close to zero.[45] At that price, the wind farm operators will be indifferent whether they are curtailed or not, which removes the questions of how to choose which farm to curtail (if there is a choice) and whether to compensate the wind farms.

[45] Nodal pricing algorithms typically also contain provisions for power plants with a minimum load, ramping constraints, start and stop costs, and parallel flows through a meshed AC network. None of these issues occur in an offshore DC grid, in which we assume the power flows are controllable. As a result, the price in a zone is determined by demand, constrained only by the available network capacity.

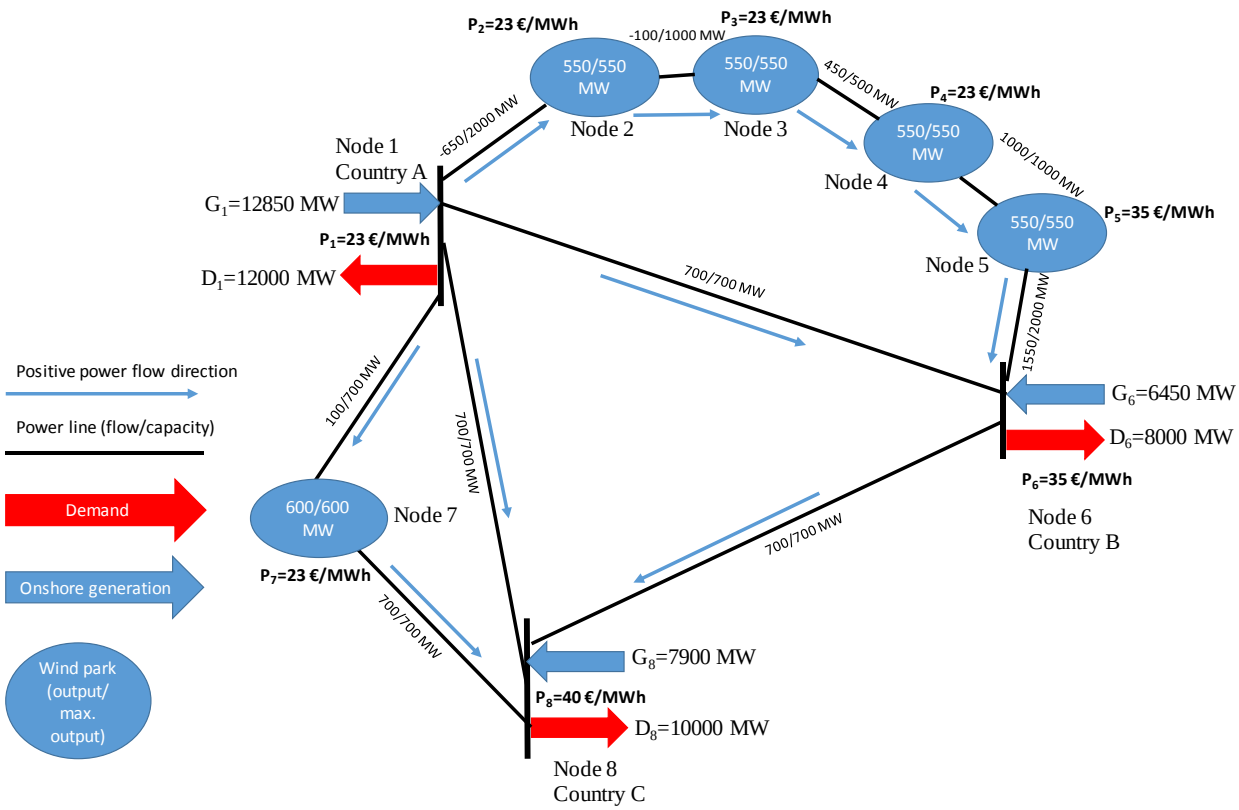


Figure 30 - Small price zones, 50% wind generation

Figure 30 presents the results for this market design. The economic dispatch is efficient, as in all our examples, and the line flows are the same as well. A notable outcome is that the price in wind nodes 2-5 is zero. This is due to the fact that the maximum wind generation capacity is larger than the network capacity. Consequently, an extra unit of wind generation at each of these nodes would have no value, as it could not be transmitted to the onshore markets. Therefore, the price is zero. This results in low generator revenues and commensurately high congestion rents during hours with oversupply (See Table 17, Table 18, Table 19 and Table 20). Depending on the grid design – it is a design choice to which degree the offshore wind parks are able to produce more electricity than can be transported to shore – this may not occur often. We will return to this issue in the comparison and evaluation section

Table 17 - Wind park revenues, many small zones, high wind

	OUTPUT	PRICE	REVENUE
	MW	€/MWh	€/h
W2	1 100	0	0
W3	900	0	0
W4	900	0	0
W5	1 100	0	0
W8	1 200	20	24 000
			24 000

Table 18 - Line flows and congestion rent, many small zones, high wind

LINE	FLOW	$P_{LOW\ NODE}$	$P_{HIGH\ NODE}$	CONGESTION RENT
	MW	€/MWh	€/MWh	€/h
F12	-2 000	20	0	40 000
F23	-1 000	0	0	0
F34	0	0	0	0
F45	1 000	0	0	0
F56	2 000	0	25	50 000
F17	-500	20	20	0
F78	700	20	40	14 000
F16	700	20	25	3 500
F67	700	25	40	10 500
F18	700	20	40	14 000
				132 000

Table 19 - Wind park revenues, many small zones, low wind

	OUTPUT	PRICE	REVENUE
	MW	€/MWh	€/h
W2	550	23	12 650
W3	550	23	12 650
W4	550	23	12 650
W5	550	35	19 250
W8	600	23	13 800
			71 000

Table 20 - Line flows and congestion rent, many small zones, low wind

LINE	FLOW	$P_{LOW\ NODE}$	$P_{HIGH\ NODE}$	CONGESTION RENT
	MW	€/MWh	€/MWh	€/h
F12	-650	23	23	0
F23	-100	23	23	0
F34	450	23	23	0
F45	1000	23	35	12 000
F56	1550	35	35	0
F17	100	23	23	0
F78	700	40	23	11 900
F16	700	23	35	8 400
F67	700	35	40	3 500
F18	700	23	40	11 900
				47 700

In the low-wind case – and whenever there is enough network capacity to evacuate all generated electricity to shore – the results of a market design with small price zones is more intuitive. Without curtailment, the zonal prices become equal to the onshore prices to which they are connected without constraints. Node 5 receives the price of Country B, as it is connected by an uncongested line. Line 4-5 is congested, and as a result all parks 'upstream' of this line receive the price of Country A, as any additional output in these nodes would flow to this country. Node 7 also receives the price of Country A, even though it produces less than the line capacity from Node 7 to Country C. The reason is that the remaining space on Line 7-8 is used to export electricity from Country A to Country C, which causes the line to be congested. (Again: an additional MW of output in Node 7 would reduce exports from Country A to Country C and therefore reduce the cost of generation in Country A; thus the marginal value of generation in Node 7 is the price of Country A.)

COMPARISON AND EVALUATION

COMPARISON OF THE NUMERICAL EXAMPLES

We will now compare the effects of the four market arrangements in our example setup. We assumed that onshore markets and onshore network congestion are economically efficient. If there is no offshore power consumption (e.g. in the form of hydrogen production), the main impact of the offshore market design is on the distribution of revenues between network operators and wind generators.[46] Although the total societal benefits will not change between the options, in practice there are reasons why the distribution of revenues between the network operator and offshore wind generators does matter. First of all, the congestion rents may accrue to a TSO in a different country than the one that is paying the renewable energy subsidies, as a result of which the application of these rents towards the subsidies may be complicated. Secondly, higher subsidy payments to offshore wind parks may reduce the public and political acceptance of this source of electricity generation, even if the higher subsidies are offset by equally higher congestion rents that can be considered to offset the welfare effects of the congestion rents at a macro level. Importantly, higher congestion rents and the associated lower offshore wind generator revenues may reduce the probability that the wind parks become profitable without subsidies. This may be a reason to prefer a market design with low congestion rents. Thirdly, offshore power conversion, e.g. into hydrogen, would require efficient economic signals, especially in case of network congestion and local energy surpluses.

Extending national electricity price zones into the North Sea (Option 1) appears to be an intuitive solution, as this is currently the case almost everywhere, as nearly every offshore wind farm is connected to only one country. The North Seas Offshore Grid Initiative (2012) tends towards this model. However, this market design leads to arbitrary differences in incomes between wind parks, depending on the price zone in which they happen to lie. In a future scenario, wind parks that lie close together and have similar cost structures and similar options for evacuating their power may receive very different prices, depending on the onshore conditions. This may result in arbitrary incentives to locate in one national economic zone of the sea instead of another and may therefore reduce the economic efficiency of the development of offshore wind. It may also lead to situations in which power needs to flow from a higher to a lower price zone, if dispatch is to be economically efficient. In this case, the TSO or another party needs to pay the price difference, as was shown in Section 0. (On the other hand, there are many other national distortions of the construction costs and electricity prices, such as taxes and labour law for construction crews.)

[46] There are other aspects to market design, such as the balancing market, which we have not discussed.

Creating a separate offshore price zone (Option 2) removes the problem of negative congestion rents but also reduces wind park revenues. Moreover, it does not provide efficient local incentives, e.g. for curtailment, storage or power-to-X conversion. If wind generation needs to be curtailed, the presence of a positive price for a larger area will discourage the development of local flexibility options such as offshore energy storage or power-to-gas conversion. Assuming that only part of wind generation in a node would need to be curtailed, the remaining generation would still receive the zonal price, raising the electricity cost of local energy storage or power conversion to the general market price, even though the local marginal value of wind generation would be zero. Finally, there is the question of how to define the limits of the zone: would it cover all of the North Sea, would it extend towards the Baltic and the English Channel…? The larger the zone, the larger the differences in market value of the generated electricity are likely to be, and therefore the larger the economic distortion of prices that deviate from the local marginal cost of generation will be.

The small price zones market design (Option 3) appears the most attractive solution to these issues. The price zones should be defined in such a way that there is no network congestion within a zone. In case a wind park is connected to only one onshore market, this solution converges with the national price zone model. However, as soon as a wind park is connected to multiple markets, the advantages of this model become apparent. Without congestion within a price zone, the price of each zone can be set equal to the marginal social value of power generation in that zone. This means that there will not be counter-intuitive flows from high to low price zones and the incentives for local flexibility will be economically efficient. The definition of the zones is a function of network capacity and therefore unambiguous. In case of curtailment, the zonal market price signals the fact that the local marginal value of generation is (nearly) zero; given this market price, wind farm operators will be indifferent whether they are curtailed or not.

At the end of Section 0, we mentioned that in addition to the welfare effects that were the subject of the numerical examples, we should consider the impact upon investment in offshore wind parks and design considerations such as the impact upon installations that convert electricity to other energy carriers (‘power-to-X’, whether to be used as such or whether to be converted back to electricity). These considerations will be discussed in the next two sections. In Section 0 we will discuss options for compensating wind farm operators in case curtailment reduces their revenues unacceptably. In Section 0 we will review what implementation of this market design would look like if we start from the current situation.

INVESTMENTS IN OFFSHORE WIND PARKS

If offshore wind generators continue to be remunerated through some form of tendering of contracts for differences, as is the current practice in Germany, the UK, the Netherlands and Denmark, the effect of the market design investment decisions in wind parks is likely limited. The governments and network providers decide both the quantity of wind generation and the parks’ locations through the design of the meshed offshore grid and the permitting and tendering processes. A caveat should be made that a market design that leads to a lower market price means that more support is needed and that fewer offshore wind farms can be built for a given budget; the fact that there are higher congestion revenues which reduce the need for public funding elsewhere in the system does not automatically translate into more budget for the offshore wind farms.

To the extent that market prices affect investment in offshore wind, for instance in case of limits to the subsidy or unsubsidised investment, small price zones are preferred as their prices indicate where in the meshed offshore grid the (marginal) value of new wind capacity is highest. For instance, if subsidies are auctioned over a large area, wind park operators will tend to choose the most valuable locations (which provide the highest market

prices) because there they can request the lowest subsidies. In this way, the locational incentives are economically efficient, even in the presence of the risk-mitigating effects of the subsidy tenders. However, the magnitude of this effect may not be large, as the meshed offshore grid operator and the government together have the main say in where new wind parks will be sited.

OPERATIONAL CONSIDERATIONS

We did not review operational issues such as the relation between the sequence of short term markets (day-ahead, intra-day and balancing) and congestion management. Given the uncertainty in weather forecasts, offshore wind park operators will need to be able to update their schedules. Generally, the closer to real time trade takes place, the better for the offshore wind generators.

Schröder (2013) suggests that national price zones are the preferred solution because this allows wind generators to pool with other (onshore) generation in order to reduce their imbalances. However, congestion of the meshed offshore grid will complicate this, even if the congestion is not so large that it leads to curtailment, but only to some generated wind being exported to lower-priced zones. Moreover, this model would discourage any offshore development of energy conversion or storage. In the many small zones market design, it could still be made possible for wind park operators to pool their imbalances within their price zones. Pooling between zones could also be facilitated, but would require the reservation of network capacity for balancing energy flows. It might be more efficient for them to participate in national balancing markets if they are efficiently organised.

The introduction of facilities that convert power to other energy carriers such as hydrogen ('Power-to-X') could change the technical and economic dynamics of the offshore grid substantially. Such an energy carrier may be transported to the shore via its own infrastructure or it can be converted back to power at times when there is little wind generation. Both options allow for a more efficient use of the offshore transmission infrastructure, as they facilitate the usage of peaks in generation, thereby reducing the need for either curtailing wind generation or for over dimensioning transmission capacity, while re-conversion to electricity also makes it possible to use the network better during low-wind periods.

The only reviewed market design that provides efficient operational incentives to Power-to-X facilities is the small zone market design. The reason is that it sets the price in the node of the Power-to-X facility equal to the local marginal value of power, which can be zero in case of curtailment. As a result, the Power-to-X facility has an optimal incentive to absorb surpluses, as opposed to a market design in which the price is averaged out over a larger are, as in case of national and separate offshore price zones. In this case, prices in small price zones also indicate the optimal location in the meshed offshore grid for building such facilities. In the market designs with large zones, the smoothing out of prices over a geographic area removes this aspect as well. If the Power-to-X facilities were located in Node 3 or 4 and its capacity were less than the curtailed volume, the market price would remain zero in these nodes. If it consumed more than the curtailed volume of wind generation, then at least one power line to the onshore markets would no longer be constrained and the nodal price would become 20 €/MWh in the example of Figure 29.

An advantage of the small zones model is that there is no longer a need for priority access for renewable energy to the network. Because wind generation has the lowest marginal generation cost, wind park operators can always bid lower than other generators, aside from solar generation, as a result of which it will generally receive the available capacity in the meshed offshore grid first. An exception is a scenario with very much renewable energy in which the meshed offshore grid is used to transport a surplus of onshore solar and wind energy to another country, in which case the onshore price may also be zero. In this case, the total volume of generated

wind and solar energy exceeds the demand plus export capacity of the country and some of it needs to be curtailed. As the market price will be close to zero, the curtailed generators should be indifferent, although there still may be a need for a system that decides which generators will be curtailed.

It is possible to include network losses in the determination of offshore zonal prices, as is done in some nodal pricing algorithms. Parks that are located further from the market will receive a lower price, as less of their output will reach the market. In case there is a need for curtailment, parks that create larger network losses will be curtailed before other parks if offshore wind parks operators bid a positive price.

COMPENSATING OFFSHORE WIND PARK OPERATORS FOR CONGESTION RENT

It was already mentioned that a potential disadvantage of the small zones market design is that it may lower the revenues of the offshore wind farms in case there is frequent curtailment. In our examples, this scenario was perhaps exaggerated by the presence of significant network congestion and high wind, but it may become a real issue as overplanting wind farms is economically efficient. It is possible to return the congestion rents to the offshore wind generators without losing the economic benefits of marginal cost pricing (which causes the price in a zone to become zero in case there is excess supply).

Offshore wind parks could be provided with a contract for differences between their zonal price and the onshore market price of their economic zone. They would receive this price difference (in €/MWh) for the volume of electricity that they produce (in MWh) for every hour in which they are active. Note that this is different from a Financial Transmission Right, as the financial compensation only pertains to actually generated electricity, up to the contracted volume. The grid operator, who is the counterparty for the contracts, should ensure that the volume of the contracts (in MW) does not exceed the volume of grid capacity that he can reliably provide, so the contracts for differences relate only to actually produced electricity.

The effect of this arrangement is that the wind farm operators receive the onshore price of their zone, but only for the volume of generated energy that can be evacuated. In case of a need for curtailment, the excess supply in the offshore price zone will cause the price to drop to zero, which would make the wind farm operators indifferent to being curtailed for the volume of generation that is not covered by the contract for differences, while they would still receive a fair market price for their non-curtailed output. A second benefit arises in the presence of energy storage or power conversion facilities in the offshore zone, as they have an incentive to consume the excess generation that would otherwise be curtailed.

If we return to the situation in Figure 29, the grid operator could provide the wind park operator in Node 7 with a contract for differences between the price in Node 7 and the price in Country C. The volume of the contract would be 700 MW, even though the park has a capacity of 1200 MW, because the net capacity between the park and Country C is 700 MW. So in the high wind scenario, the wind park in Node 7 would be paid 700 MW x (40-20) €/MWh. This is equal to the congestion rent on the line between this park and Country C, so the net result is financially neutral for the grid operator. The wind park could receive a second contract for differences with Country A, for a volume of 500 MW, which would protect it in case the market price in A was higher than in C.

The contracts for differences for zonal prices also reduce the risk of curtailment. They do not remunerate the curtailed energy but they protect the wind farm operators from low revenues when their nodal price is lower than the onshore price. If there is only one wind park in a node, the wind farm operator could solve the problem through self-curtailment, but in case of multiple wind parks in a given node, the contracts for difference will

provide fair remuneration to the volume of generation capacity that can be evacuated and zero revenue to the remainder, which the wind farm operators will then be willing to curtail.

For instance, again in the situation of Figure 29, 200 MW of the electricity that can be generated in Nodes 2 and 3 needs to be curtailed. In the figure, this takes place in Node 3. The market price is zero in both nodes. If the operator in Node 2 has a contract for difference with the market price in Country A of 1100 MW and the one in Node 3 a contract for difference with a volume of 900 MW, the wind farm in A will have an incentive to produce 1100 MW. The farm in Node 3 receives the market price of country A only for a volume of generated power of up to 900 MW, so it will not object to curtailing the remaining 200 MW. The contracts could also have been allocated differently in this case: both wind parks could have received a contract for differences of 1000 MW, in which case both farms would have curtailed 100 MW. We propose that the operator of the meshed offshore grid allocates the contracts to the wind farm developers at the time when they receive their construction permits and connection rights. The contract for differences should be part of the package for which the wind park operators bid because it adds value to the wind park.

In a situation with less wind, when the park produces less than its full capacity and the zonal price is positive, the contract for differences may still benefit park operators. In the example case of Figure 30, the price in Node 7 would be 23 €/MWh, but the contract for differences with Country C would give the park owner the right to an additional (40-23 €/MWh), providing him with a total revenue of 40 €/MWh for the 600 MW that he can produce at that moment.

In conclusion, contracts for differences provide the park operators with fair market value for the energy that they can sell onshore. Park operators may decide themselves to install more generation capacity than the network can evacuate during peak generation moments, in order to be able to produce more wind energy when there is less wind. At times with excess generation, the zonal price will be zero and the park operators will be indifferent to curtailing wind generation that is not covered by a contract for differences, so curtailment will not need to be compensated.

IMPLEMENTATION OF THE SMALL ZONES MARKET DESIGN IN THE CURRENT SITUATION

The examples that we used were construed to show cases in which wind parks are shared between countries and in which wind parks are connected in series in a grid that does not always have the capacity to evacuate all wind energy. While these cases may occur in a highly meshed offshore grid, the near future of the North Sea wind industry will be characterised by a simpler topology. It is our goal that the market design functions in both a simple and more intricately meshed grid, with sufficient as well as with periodically tight network capacity. The above examples showed that the small zones model functions best in meshed grids with or without congestion. Now we will show that it also functions well in the simpler topologies with which the development of a meshed offshore grid will begin.

We start with the example that is shown in Figure 31. Applying the principles of the ‘many small zones’ market design to a number of wind parks that have only single connections to the shore gives the same results as the national price zones: because the parks can only sell in one market, they receive that market’s price. Thus Wind Parks 1 and 3 would receive 23 €/MWh, the price of Country A, and Wind Park 2 would receive 30 €/MWh, the price of Country B. In case of over planting and congestion, the price in the offshore wind zones would drop to zero, but the compensation measure would return the price to the national price.

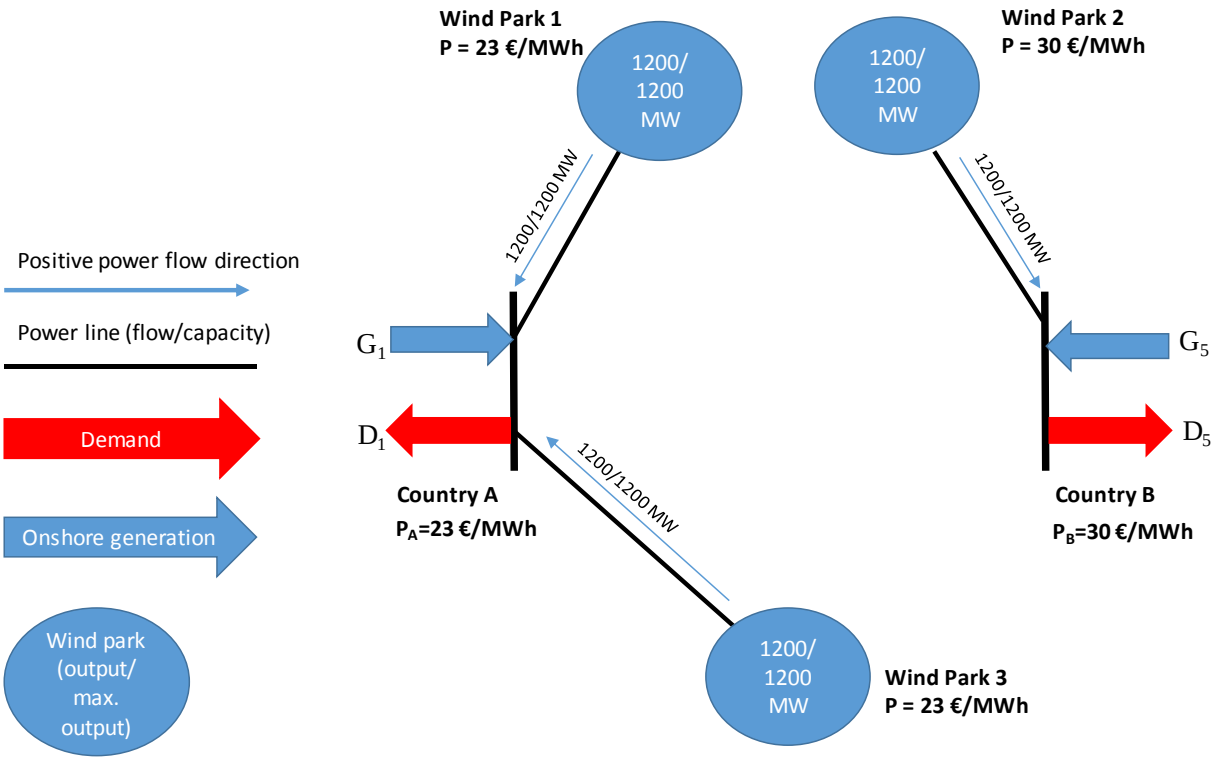


Figure 31 - Wind parks with single connections

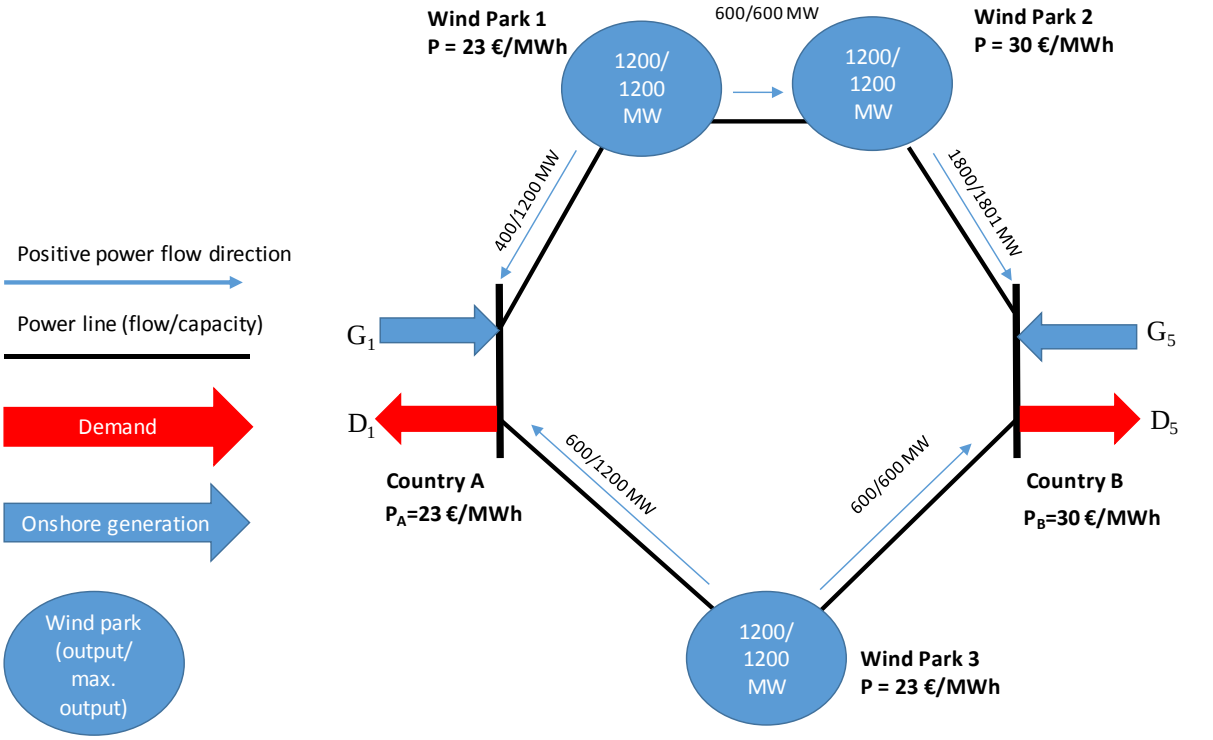


Figure 32 - Simple network, small price zones

Now if we add some connections, a simple degree of meshing develops. Let us assume that a 600 MW link is built between Wind Parks 1 and 2, that the connection between Wind Park 2 and the mainland of Country B is strengthened to 1801 MW (just large enough so it is never congested) and that Wind Park 3 is connected to Country B with a 600 MW, as is depicted in Figure 32. Now more power flows to the higher price zone, but the wind park revenues remain the same. The reason is that the new transmission links to the higher priced zones are congested, as a consequence of which Wind Parks 1 and 2 still deliver some power to Country A. Therefore,

the price in Country A is the marginal value of generation in Wind Parks 1 and 2. In this example, the results are the same as in case of national price zones because the congestion is on the transmission cables between the countries' zones.

Now if there is less wind in this configuration and there is no network congestion, then all the parks will deliver to the high-priced zone and receive that price, as is shown in Figure 33. Now the advantage of the flexibility of the small price zones market design becomes apparent: while the volume of wind generation is lower, Parks 1 and 2 are able to capture the higher price of Country B, thereby maximizing their revenues.

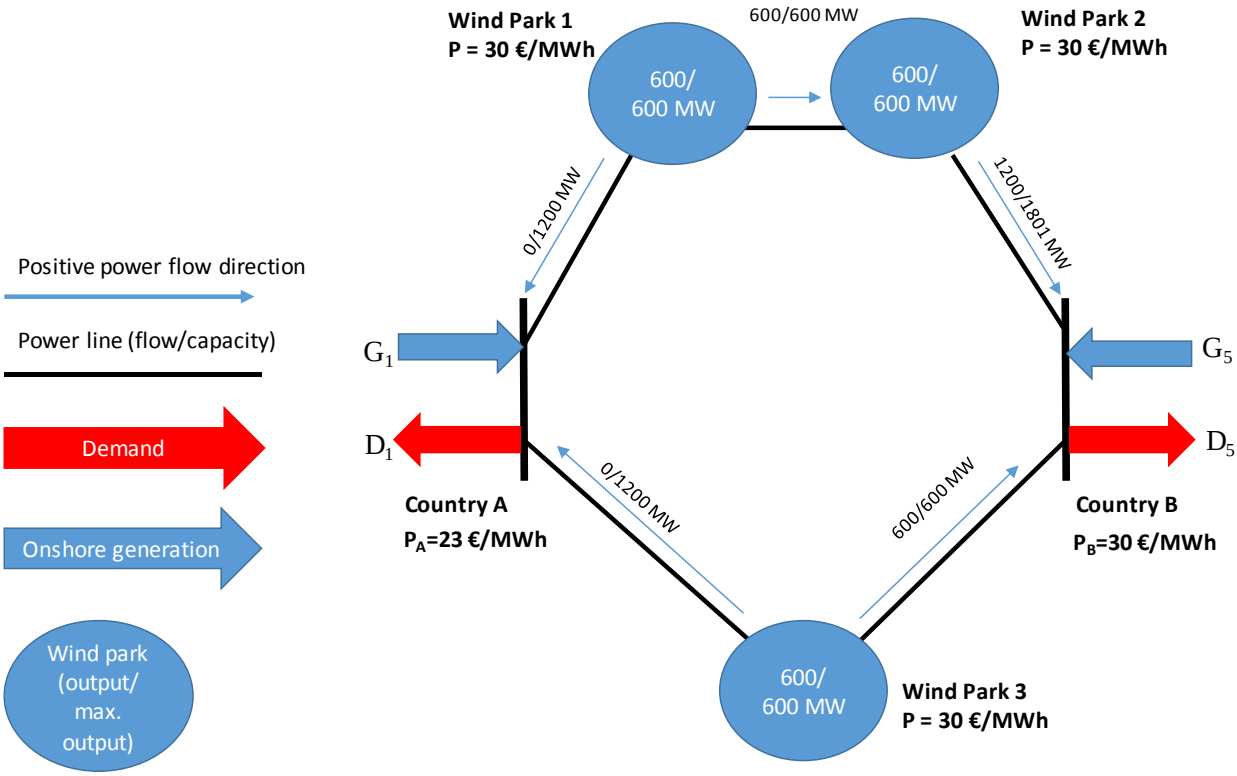


Figure 33 - Simple network, small price zones, less wind

LEGAL CONSIDERATIONS

The small bidding zones market design and its application to hybrid projects raises two legal questions. The first concerns the legal status and classification of the power cables between bidding zones. The second question is whether the small bidding zones market design complies with the substantive rules of EU energy law. The two parts will be discussed separately below.

LEGAL STATUS OF THE ASSETS

There are three options for the legal status of the cables between bidding zones under EU law.[47] The first option is to consider them as part of the national transmission network of the coastal state. This means that they will be incorporated in the regulated asset base (RAB) of the responsible TSO.[48] This is the way the grid components of Kriegers Flak Combined Grid Solution are categorised. The second option is to consider them as interconnectors, but this only applies to cross-border transmission infrastructure. Thus, not all power cables in a meshed grid will

[47] National law follows EU law to a large extent, but there may be national differences with regard to the rules on whether a cable can be considered part of the national transmission network.
[48] Assets in the RAB receive income from the tariffs paid by the grid users (consumers or producers, depending on the national rules). The level of the income is determined by the NRA. For hybrid assets, the (nationally determined) income rules may have to be adjusted regarding the specific usage of such assets.

be considered as interconnectors, only cables that physically cross a border. Considering an infrastructure link as an interconnector entails that it must adhere to the specific rules for interconnectors as laid down in EU Energy Law. (See below.) Interconnectors are either part of the RAB of the involved TSO and regulated as such, or they are exempted (merchant) interconnectors if they have obtained an exemption from the Electricity Market Regulation.[49] The third possible option is to consider them as 'offshore hybrid assets', as defined in the Electricity Market Regulation.[50] As there is no substantive law concerning the third option, this is not yet available for hybrid projects within the coming few years.

Different parts of the infrastructure may be given a different legal status. One may imagine a situation in which the connection from the onshore price zone to an offshore price zones is considered as part of the national transmission grid, whereas a network link between two offshore price zones that crosses a border between two EEZs will be considered as an interconnector. On the other hand, the complete offshore electricity network could also be considered as one indivisible infrastructure, which would then automatically be an interconnector due to the definitions in EU law. The categorization is necessary to determine which substantive rules of EU and national energy law are applicable.

SUBSTANTIVE RULES

There are no major legal impediments in EU law to the small bidding zones market model. Nevertheless, some national rules will need to be changed. The following substantive rules are important for cross-border infrastructure:

- For any cross-border electricity infrastructure, 70% of the capacity should be available to the market, to which all market participants have non-discriminatory access.[51] The small zones market model is compatible with this rule. In practice, the OWFs that are connected to the small bidding zones will be able to access the transmission infrastructure as normal market participants, because they will be able to bid in lower than other market participants and thus gain access. The only exception to this situation is when there are negative prices in one of the countries. However, this situation rarely occurs, and typically only for limited time. Moreover, negative prices are a market failure that is already addressed separately, so their occurrence is expected to diminish in the future.

  Link to the legal status of the assets: This rule applies to regulated assets, such as the national electricity grid and regulated interconnectors. If an asset receives an exemption for new interconnectors, the project developer may deviate from the rules concerning non-discriminatory third party access, which means that he may give precedence to OWFs connected to it. However, because the OWFs will be able to evacuate their electricity in normal market situations, there is less need for exemptions.
- In the small zones market design, congestion revenues arise when the transmission capacity between two bidding zones is not sufficient to meet demand. A hybrid project that connects multiple bidding zones may therefore generate congestion rent. EU Law prescribes that congestion income be used with priority for guaranteeing the availability of the assets and/or for maintaining or increasing cross-zonal capacities

[49] Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity, article 63. There is a list of rules to which an interconnector should comply to be able to receive an exemption. The exemption allows interconnectors to deviate from some important rules, as will be explained below. A merchant interconnector cannot receive regulated income, thus, congestion is its sole source of income.
[50] Ibid., recital 66.
[51] Ibid., art. 16(8).

by optimizing the use of existing interconnectors.[52] (The rule that congestion income should be applied to the construction of new interconnection capacity has been scrapped.[53])

Link to the legal status of the assets: This rule applies to regulated interconnectors only. If the asset receives an exemption for new interconnectors, the project developer may deviate from the rules on how congestion income can be used. However, since the rules are more lenient now, there is less of a need to deviate from the rules.

- The bidding zone review rules dictate that "bidding zone borders shall be based on long-term, structural congestions in the transmission network. Bidding zones shall not contain such structural congestions unless they have no impact on neighbouring bidding zones (…)".[54] From the perspective of this article, the small bidding zones model is more suitable than the other market models, as structural congestion is to be expected on hybrid assets (there is no copper plate between the onshore grid and the OWF), and by their nature, the congestion has an impact on neighbouring bidding zones.
- The national rules concerning support schemes for OWFs connected to a small bidding zone will need to be changed. The electricity that is generated by offshore wind farms will no longer automatically flow to the onshore grid of the coastal state. In some countries, this is a requirement for support: OWFs only receive support for the amount of MWh that reach the onshore grid. The support scheme rules need to be changed in such a way that OWFs have sufficient certainty about their income, regardless of the direction of the flows of electricity. Moreover, the support schemes should allow the form of Contract for Difference bidding proposed in section 5.4 to offset congestion rents.

CONCLUSIONS

Splitting the meshed offshore grid into small price zones, while returning the congestion rents to the wind farm operators, appears to be the most attractive market design for a meshed offshore grid. The price zones would be defined by the existence of network congestion, like in Nordpool. Wind farms without congestion between them would receive the same price. This model can be implemented from the start of the development of a meshed offshore grid, when most parks have single connections to the shore. In this phase, the results will resemble the national price zone model. However, when the offshore electricity network becomes meshed and in case electricity is stored and/or converted to another energy carrier offshore, it becomes necessary that the local electricity price offshore reflects the local marginal value of electricity. National price zones do not provide this incentive and may cause situations in which economically efficient dispatch would require trading power from a high price to a low price zone. A single offshore price zone avoids the latter, but still does not provide efficient incentives for power conversion.

A degree of over dimensioning of the wind parks, as compared to the grid capacity, is rational because it increases the utilization rate of the network. (However, in PROMOTioN, the goal has been to avoid curtailment altogether by providing sufficient network capacity.) A disadvantage of allowing congestion is that congestion reduces the revenues of the wind park operators. We propose to compensate the wind farm operators for these congestion costs by allocating contracts for differences to them for the difference between their offshore zonal market price and a reference onshore price. This improves the business case for offshore wind and reduces the

[52] Ibid., article 19. This is the case for cross-border links. Whether it is also the case for internal lines depends on the national rules concerning congestion rents.
[53] Regulation 714/2009, art. 16(6).
[54] Regulation (EU) 2019/943, art. 14.

need for financial support, while maintaining the economic efficiency of the price signal. The contracts should be awarded on a competitive basis. In case the wind park developers bid for the permission to develop a park in a certain location (often including the network connection), the contract for differences should be included as part of this package.

We base these conclusions on a set of simple numerical examples, extended with a qualitative assessment of the market design options. In these examples we make certain assumptions, as a result of which the economic efficiency of the dispatch of generation is not affected by the choice of pricing rule. This is the case if the wind parks require subsidy, if network congestion is handled efficiently onshore as well as offshore, and if the onshore markets are organised efficiently. A result of these assumptions is that the generation dispatch and network flows are the same under all reviewed pricing rules, as a result of which the prices in the onshore price zones are also the same in all examples. The differences lie in the revenues of the wind parks and the network operators. They are communicating vats: lower revenues for the wind park operators mean higher congestion revenues for the network operators and vice versa. At first glance one might conclude that there is not much difference, therefore, but:

- Lower market revenues for offshore wind parks entail a higher need for financial support.
- All market designs other than one with small price zones (or locational marginal pricing) discourage investment in flexibility options such as energy storage and power-to-gas within the meshed offshore grid.

From a legal perspective, the cables between bidding zones will have to adhere to the rules on availability and congestion rents. There are no major impediments to the small bidding zone model in EU law. Instead, EU law promotes an organization of the bidding zones according to structural congestions, which makes the small price zones model more appropriate than the other models from a legal perspective. In order to allow for the contracts for differences, some national legislation on the organization of support schemes will have to be changed.

As a follow-up, we recommend a study of the performance of the proposed market design in a simulation model with a realistic meshed offshore grid topology would provide insights in the expected impacts of this market design on the revenues of wind parks and the network operator. As a start, past data from Kriegers Flak (wind generation and market prices) can be used to simulate how this market design would have performed in that case.

VI. APPENDIX – GRANT AGREEMENT PROJECT OBJECTIVES

The project "Progress on Meshed HVDC Offshore Transmission Networks" (PROMOTioN) addresses the challenges for developing meshed HVDC offshore networks by setting six clear, ambitious objectives (Table 21). The overarching objective is to develop the technologies for meshed HVDC offshore grids to enable large scale, commercial application. All PROMOTioN partners are convinced that successfully addressing these six ambitious objectives will significantly accelerate the deployment of meshed HVDC offshore grids in the North Sea area and other continental power corridors. Successful completion of the project will be a major step forward in commercialising HVDC transmission grids. A particular strength of PROMOTioN is the ability to take into account different perspectives by bringing together all relevant HVDC manufacturers, network operators, wind farm developers, consultants and academia with a common vision and goals.

Table 21 - Overview of the project's six core objectives and the associated work packages

#	Core project objectives	Work Package
1	To establish interoperability between different technologies and concepts by providing specific technical and operational requirements, behaviour patterns and standardization methods for different technologies	WP 1, WP 2, WP 3, WP 4, WP 5, WP 6
2	To develop interoperable, reliable and cost-effective technology of protection for meshed HVDC offshore grids and the new type of offshore converter for wind power integration	WP 2, WP 3, WP 4, WP 5, WP 6
3	To demonstrate different cost-effective key technologies for meshed HVDC offshore grids and to increase their technology readiness level by investigating and overcoming early adopter issues and pitfalls	WP 8, WP 9, WP 10
4	To develop a new EU regulatory framework, both in accordance with EU wide energy policy objectives and those of the Member States, and to increase the economic viability of meshed HVDC projects by providing a suitable financial framework	WP 1, WP 7, WP 12
5	To facilitate the harmonization of ongoing initiatives, common system interfaces and future standards by actively engaging with working groups and standardization bodies and actively using experience from the demonstrations.	WP 11
6	To provide a concrete deployment plan for "phase two" in bringing key technologies for meshed HVDC offshore grids into commercial operation in Europe, taking into account technical, financial and regulatory aspects	WP 7, WP8, WP 12

To deliver the first objective (interoperability) technical requirements and standards must be specified for HVDC technologies that enable both the HVDC network itself to operate stably, and to enable the HVDC network to interact with the existing power transmission and energy supply/demand infrastructure. These are both currently insufficiently defined and are likely to be topology specific.

The second objective is to prepare enabling technologies to be ready for large scale application. The lack of standardised approaches for grid protection is a significant barrier to HVDC technologies achieving higher TRL, as operational system security is a key priority of all European transmission system operators. In this project, the key enabling technologies will be prepared for large scale operation within meshed HVDC offshore grids. Consequently, PROMOTioN will develop standardised approaches for using these supplementary technologies with a particular focus on the protection of meshed HVDC offshore grids.

The third project objective aims to demonstrate enabling HVDC technologies. Demonstration will be performed in a relevant operational environment in order to investigate their behaviour under realistic conditions, to assess and optimise their performance and to overcome early adopter issues and pitfalls. The demonstrations in PROMOTioN do not only focus on a single aspect, but comprises of three technologies. Demonstrations include the demonstration of advanced protection systems for meshed HVDC offshore grids and the demonstration of HVDC breakers performance and the associated test methods and procedures.

The project's fourth objective aims at reducing the financial and regulatory risk of meshed offshore DC grids, both during development and operation. In order to facilitate networks' large scale commercial application, a new EU regulatory framework will be developed. Proposed regulations will be in accordance with EU wide energy policy objectives and as well as the Member States involved, and will enable a secure and efficient transnational operation of the grid. Furthermore, financial aspects will be addressed, by building a financial framework which enables the bankability of these large scale investment projects and enables the build-up of suitable revenue streams.

A further aspect of major importance is the harmonization of ongoing activities at European and international scale. A number of different stakeholders, working groups and standardization bodies are aiming to achieve consensus on different technical aspects of DC technologies development. However, in some areas there is a lack of a common perspective and an urgent need to align. Based on the results from the demonstration phase, PROMOTioN aims to facilitate the harmonization of ongoing initiatives, common system interfaces and future standards by actively engaging with working groups and standardization bodies to facilitate large scale commercial deployment.

The sixth and final objective of PROMOTioN is development of a concrete deployment plan, outlining the required actions beyond the project itself to bring meshed HVDC offshore grids into large scale, commercial application after 2020. A particular emphasis will be put on the activities associated with this objective, as they tie together the outcomes and deliverables of all project parts. Results of PROMOTioN will be transformed into specific action steps. The work packages associated with the sixth core objective will reduce planning and investment risks by providing additional insight from the results of other existing studies and identifying best scenarios for infrastructure decisions in the North Sea region and other European priority areas.