D12.4 - Final Deployment Plan

PROMOTioN – Progress on Meshed HVDC Offshore Transmission Networks
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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.

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DOCUMENT INFO SHEET

Document Name: **Final Deployment Plan**
Responsible partner: TenneT TSO B.V.
Work Package: WP12
Work Package leader: TenneT, John NM Moore
Task: T12.3
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DOCUMENT HISTORY

Version	Date	Main modification	Author
1.0	26 February 2020	Change of D12.3 into D12.4	Hannah Evans
2.0	23 July 2020	Final review version	Hannah Evans/ John Moore/ Cornelis Plet/ Jelle Van Uden/ Laurens de Vries / Christina Brantl
3.0	14 Sept 2020	Final version	Hannah Evans/ John Moore/ Jelle Van Uden

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
12.4	Final Deployment Plan	Report	PROMOTioN	54

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LIST OF ABBREVIATIONS

ACRONYM	FULL NAME
AC	Alternating Current
ACCB	Alternating Current Circuit Breaker
ACER	Agency for the Cooperation of Energy Regulators
AIS	Air Insulated Switchgear
BAU	Business As Usual (Grid Concept)
BIL	Basic Insulation Level
BRP	Balance Responsible Party
BSP	Balance Service Provider
CAPEX	Capital Expenditure
CBA	Cost-Benefit Analysis
CBCA	Cross-Border Cost Allocation
CEF	Connecting Europe Facility
CENELEC	European Committee for Electrotechnical Standardization
CO_2	Carbon Dioxide
DC	Direct Current
DCCB	Direct Current Circuit Breaker
DCL	Direct Current transmission Line
DMR	Dedicated Metallic Return
DRU	Diode Rectifier Unit
EB GL	European Electricity Balancing Guideline

EC	European Commission
EEA	European Economic Area
EEZ	Exclusive Economic Zone
EIA	Environmental Impact Assessment
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSO-G	European Network of Transmission System Operators for Gas
EPC	Engineer, Procure and Construct
EU	European Union
EUR	European Distributed Hubs (Grid Concept)
FB	Full Bridge
FRT	Fault Ride Through
FTR	Financial Transmission Rights
GIS	Gas Insulated Switchgear
GW	Gigawatt
HB	Half Bridge
HSS	High Speed Switch
HUB	European Centralised Hubs (Grid Concept)
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IED	Intelligent Electronic Device
IGBT	Insulated Gate Bipole Transistor
IMO	International Maritime Organisation
ISO	Independent System Operator
KPI	Key Performance Indicator

LCC	Line Commutated Converters
LOLE	Loss of Load Expectation
MMC	Multi-Modular Converter
MOG	Meshed Offshore Grid
MOSA	Metal Oxide Surge Arrestor
MSP	Marine Spatial Planning
MV	Medium Voltage
NAT	National Distributed Hubs (Grid Concept)
NRA	National Regulatory Authority
NSEC	North Seas Energy Cooperation
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
QA	Quality Assurance
QC	Quality Control
RAB	Regulated Asset Base
Radial	A radial connection is a point to point connection without multi-terminal or meshing is applied.
RCC	Regional Coordination Centre
RES	Renewable Energy Sources
SCFCL	Short Circuit Fault Current Limiter

SF_6	Sulphur hexafluoride gas
SM	Sub-Module
SO	System Operator
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
UNCLOS	United Nation Convention on the Law of the Seas
UK	United Kingdom
VARC	VSC Assisted Resonant Current
VSC	Voltage Source Converter
WG	Working Group
WP	Work Package
XLPE	Cross-Linked Polyethylene

EXECUTIVE SUMMARY

INTRODUCTION

At the end of 2019, 22.1 GW of offshore wind capacity was installed across Europe with 90% 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 the installed capacity continues to grow, with a clear pipeline of projects stretching into the 2020s across the North Seas countries [2]. Currently, most of the existing offshore wind generation (~16 GW) is transmitted to shore using point-to-point High Voltage Alternating Current (HVAC) connections. As distance to shore increases, the need to use High Voltage Direct Current (HVDC) connections increases, in order to avoid the high amount of reactive compensation equipment necessary for HVAC power. Additionally, as the cost of transmission increases due to longer distances, it is increasingly important to maximise the use of offshore transmission assets. Therefore, a meshed or multi-terminal offshore grid is proposed as a solution, where multiple windfarms are connected to offshore transmission assets which may also operate as interconnectors between countries – so-called Hybrid Assets. This evolution from point-to-point connections towards multi-terminal and meshed grids is an attractive option which could satisfy European Union (EU) goals to efficiently integrate renewable energy and increase interconnection, while maximising social benefit.

The PROMOTioN programme (Progress on Meshed HVDC Offshore Transmission Networks) has advanced the HVDC technology required to design, build, operate and protect meshed HVDC transmission grids, namely HVDC grid and converter control systems, direct current circuit breakers (DCCBs), HVDC grid protection systems and HVDC Gas Insulated Switchgear (GIS)[1]. Alongside this, recommendations have been developed for the legal & governance frameworks needed for a meshed offshore grid (MOG), the necessary economic and financial rules required to attract sufficient investment and fairly remunerate owners, operators and users of the grid, and the market and governmental actions necessary to facilitate an ordered roll-out.

This document, Deliverable 12.4 - Final Deployment Plan, brings together these findings and recommendations into a roadmap to 2050, describing the steps required to develop an offshore grid capable of integrating offshore wind farms and evacuating large quantities of wind energy to shore, as well as providing interconnection between countries bounding the North Seas, and providing onshore AC grid reinforcements by means of offshore DC connections[2]. The aim of this document is to translate these recommendations into practical and executable next steps for the European Commission and other stakeholders to overcome barriers and advance the deployment of a MOG.

This document includes an overview of the development of possible MOG configurations, 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 stakeholder groups. This document concludes with a roadmap, which provides an overview of recommendations and when they need

[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] It should be noted that the PROMOTioN project did not model international or intranational onshore transmission constraints.

to be implemented to facilitate a smooth development of an offshore grid. An overview of the different topics that are combined to produce this Deployment Plan is given below and in Figure 1. The results from a cost-benefit analysis (CBA) on four different grid configurations under three offshore wind deployment scenarios were reported in Deliverable 12.2. From these approaches, a proposal for expected general expansion of the offshore grid was developed.

- Through development of the different technologies within PROMOTioN, recommendations on their availability and applicability within the grid are given.
- Linked to the point above, the need for a number of Short Term projects to test novel technologies has been identified. These are also incorporated in this Deployment Plan.
- Analysis of non-technological recommendations and market and governmental requirements complete the combination of different aspects in the Deployment Plan.

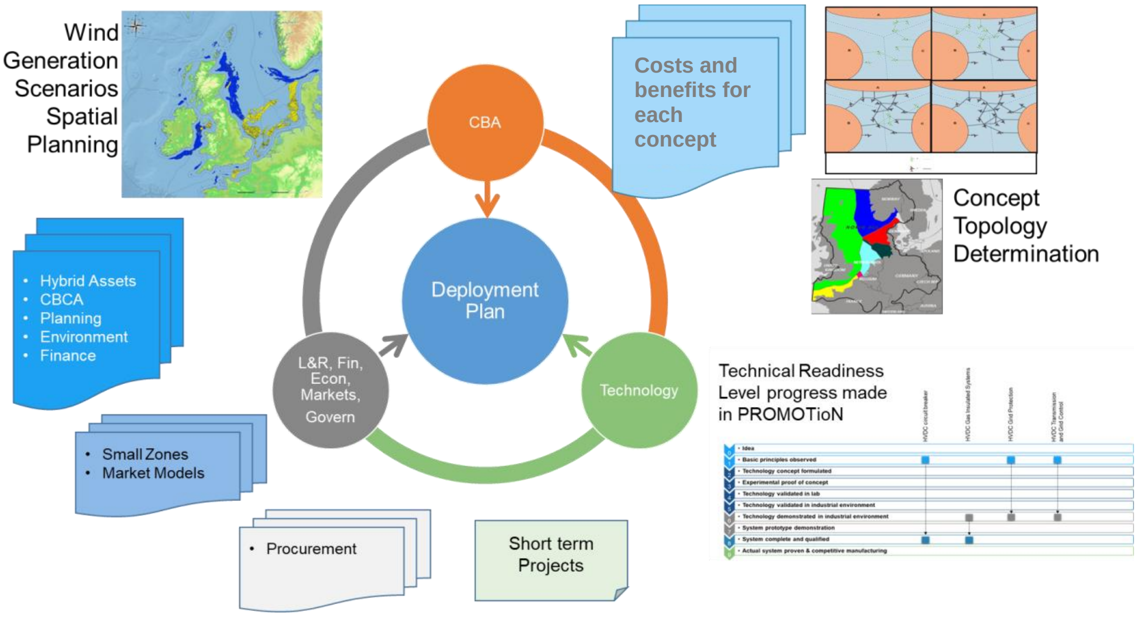

Figure 1- Overview of the elements incorporated in the Deployment Plan.

DEVELOPMENT OF THE OFFSHORE GRID

In Deliverable 12.2, four offshore grid expansion governance scenarios, or *concepts*, were analysed under three different offshore wind deployment scenarios, to produce 12 grid topologies showing the development of the grid from 2020 to 2050 in five-year time steps. The concepts ranged in their regulatory and technological complexity, allowing the exploration of 3 dimensions. The start point for all is the point-to-point grid connection (business as usual). The three dimensions are as follows:

1. The first dimension is to integrate multi-terminal and meshed grids;
2. The second dimension considers "small" 2 GW hubs to grids centred around artificial islands
3. The third dimension compares the evacuation within the National Exclusive Economic Zone (EEZ) to grids where evacuation is to the nearest landing point. A concept called here "European meshing," which is reliant on intense international cooperation.

Simulating the development of an offshore grid under the offshore wind deployment scenarios highlighted similarities and differences between the grids developed. The costs and benefits of these concepts were also analysed, using a CBA methodology developed within PROMOTioN[3].

The analyses in Deliverable 12.2 concluded that the differences between the concepts in terms of investment costs were not material. However, our analysis indicated that when constraints on meshing are relaxed, specific multi-terminal configurations arise early on in every concept, such as establishing offshore interconnectors between windfarms.

Additionally, aggregating the connection points of multiple windfarms offshore and transporting the power to shore with an individual point to point (otherwise known as radial) transmission circuit is a competitive topology and arises in all concepts. For this analysis, PROMOTioN assumed that the next generation of offshore HVDC transmission systems would settle on a voltage level of ±525 kV, with 2 GW of power transmission capacity and the configuration of an, HVDC bipole with fixed return. The selection of 2 GW is related to state-of-the-art cable technology and onshore constraints assuming a loss of only 1 GW transmission capacity in bipolar systems in case of a single faulted element.

Also, the cost reduction of using islands with larger power concentration in place of platforms became apparent in this analysis[4]. Within PROMOTioN, we did not fully optimise the location of the hubs and wind location and roll out was the same as for other concepts. Optimisation of these factors may make the concept more attractive still.

The advantages of removing constraints on evacuation of wind generated in one EEZ to a landing point in another resulted in less cable length required. However, the increased complexity and cost of hub equipment resulted in similar cost for European and National solutions.

All multi-terminal and meshed solutions indicated an improvement in benefits. Meshing of the grid, where appropriate, generally leads to lower curtailment and a higher security of supply[5]. Realising targeted benefits, however, may also require a change in the market setup around bidding zones or a new regulatory approach. Application of novel technologies will also be necessary.

While the analysis focused on four distinct grid development concepts, in reality the offshore grid is expected to consist of elements of all four of the PROMOTioN concepts, as they are geographically and temporally applied based on political preference and increased benefits. The recommendations in this roadmap are therefore generally applicable to all concepts however they are also designed to be able to steer towards the more economically appropriate concept.

The development of each topology can be split into three periods that all show similar development. The first period of 2020-2030 marks the start of the roll-out of the multi-terminal and meshed grid, during which time point-to-point connections still dominate and the multi-terminal and meshed topology of the grid is concentrated in small areas. During 2030-2040, grid development takes off and more multi-terminal and meshed topologies start to appear. The period 2040-2050 marks the end of the analysed timeframe, where

[3] Described in Deliverable 7.11, where an updated and modified version was developed of the ENTSO-E CBA methodology for the evaluation of new assets.
[4] This is explored in the HUB concept, described in Appendix i
[5] Note that the analysis highlighted high curtailment in later periods. This occurs in all concepts. This may be partially due to limits in the onshore modelling, it may indicate that some form of energy storage or Power to X is required to balance the system.

experiences gained in the previous periods can be applied to complete the integration of a large amount of offshore wind, and to inspire the repowering of the by then decommissioned offshore transmission corridors.

2020 – 2030

The first period in the development of the grid is characterised by the deployment of the first 525 kV 2 GW HVDC components and the construction of relatively simple, multi-terminal grid topologies. These topologies are limited to the national EEZs. Potential cross-border synergies are realised with the establishment of the first hybrid assets[6] located between windfarms that are close to the border of the EEZs. These topologies will provide the first opportunities to apply and test interoperability and control systems and may require the first application of HVDC protection. However, for simple topologies whose failure does not have a large impact on the connected AC systems, dedicated DC-side protection with HVDC Circuit Breakers (DCCB) may not be required. This period is also a period where the instruments for international cooperation are put in place to better align the short term Ten Year Network Development Plan (TYNDP) process with longer term system planning, provide longer term coordinated offshore generation planning and roll out the control and Governance mechanisms. It may also be prudent to consider the implementation of a small bidding zone market model.

In the PROMOTioN concept where the construction of artificial islands is allowed, artificial islands are already constructed in this period in all six predefined locations. However, PROMOTioN realises that construction of these islands may not be feasible by 2030. In reality, planning is still in a nascent stage despite ambitious targets e.g. for an island off the West coast of Denmark before 2030 [3].

To enable the increased rate of construction in 2030-2040, the availability of sufficient production capacity of the key technologies, most notably cables, and the availability of sufficient installation vessels and skilled personnel must be assessed in the light of global transmission and offshore wind roll out scenarios and increased where necessary. A long-term view of a clear pipeline of HVDC transmission projects must be created in order to enable manufacturers to make the necessary investments in production capacity. Pilots for international initiatives to improve vertical and horizontal coordination with the aim of reducing the time and effort required for planning and permitting should be initiated to ensure they are mature by 2030.

2030 – 2040

The second period in grid development sees an acceleration in the rate of offshore wind deployment, complemented by more complex cross-border multi-terminal connections and meshing. It is in this period where industrially proven protection devices will be required, interoperability between different vendors will be necessary, introducing increased technical complexity into the grid. This not only requires advanced procurement models, it is also anticipated that thorough testing of complex technology prior to installation will be required. This will make the small bidding zones market model more imperative.

Artificial islands may be established during this period and have their hosting capacity grow throughout this period to allow a significant amount of offshore wind to be connected. Bilateral or trilateral agreements may

[6] Hybrid assets are transmission systems (Interconnector cable) connections combining the functions of evacuation from an OWF and interconnection between bidding zones.

no longer be suitable, as increased meshing means more countries are connected via the same network. As a consequence, current prevailing market models and support and subsidy schemes may no longer be effective mechanisms for encouraging the deployment of offshore wind and will therefore need to be changed.

2040 – 2050

The last period in the development of the grid is a continued development of the complex topologies in the grid. Multiple overlaying multi-terminal and meshed grids may 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 production and construction process. Where possible, more interconnection capacity is established between countries, enabling the full integration of the North Seas markets.

The earlier windfarm and grid investments will reach maturity and will require life extension investment or decommissioning. The existing transmission corridors can then be repowered with technology compatible with the meshed HVDC grid.

LEGAL, REGULATORY, MARKET AND FINANCING RECOMMENDATIONS

DEVELOP A MIXED PARTIAL AGREEMENT FOR REGIONAL COOPERATION

The development of a HVDC offshore grid is a series of complex projects, including cross-border projects, with high investment requirements. Strong co-operation between countries at both a political and operational level will be necessary to develop consistent 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 time, 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 Offshore Wind Farm (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)

DESIGNING DEDICATED MARKET SCHEMES FOR OFFSHORE GRIDS

Currently, OWFs are connected to the country in whose EEZ they are located. The power generated is evacuated to shore and the OWF participates in that country's electricity market (national price zones). In an increasingly multi-terminal and meshed offshore grid, it may be more economic for the energy generated to be evacuated directly to a different country. For this reason, different market designs for OWFs in a multi-terminal and meshed grid may be necessary.

Indeed, current national price zones may cause situations in which economically efficient dispatch would require trading power from a high price to a low price zone (counter trading) and/or redispatch. A massive use of such congestion management measures could distort the market and does not provide efficient economic incentives to develop the generation in optimal locations for the overall system. Furthermore, national price zones do not provide natural incentives to develop power conversion devices (such as power to gas) or storage offshore, where it could be needed. On the other hand, a single offshore bidding zone is not relevant, because offshore grids will be far from a “copper plate” model.

Splitting offshore grids into several bidding zones appears thus to be an attractive option for an offshore electricity market providing efficient economic incentives. It is not yet clear if moving towards an extreme version of a split of offshore grids into small bidding zones, i.e. per individual OWF market model, would be desirable for all part of the offshore grids, or if a zone gathering several offshore hubs would be more appropriate. Indeed, very small zone markets could face several challenges, such as reduced liquidity, increased price volatility, discrimination between OWFs within a country, and possibility of market power. Consequently, further studies should be carried out on the division of offshore grids into small bidding zones and on mechanisms that could be put in place to ensure both a fair (re)distribution of the socio-economic welfare and favourable conditions for the development of offshore wind farms (e.g. contracts for difference, financial transmission rights, options), before a decision is made on the implementation of market schemes used for offshore grids.

In particular, this should ensure that a small bidding zone arrangement provides the right remuneration structure to incentivise the deployment of offshore wind and efficient build out of transmission assets. These studies should be prioritised to minimise the number of multi-terminal grid projects built under bespoke ‘exemption’ business models which may not easily be integrated into a wider multi-terminal and meshed transmission network. Similarly, OWFs supported by national subsidy schemes may struggle to be subsequently integrated into a different bidding zone model and support mechanism. It should be possible to implement the small bidding zones model without any change to the existing network codes, and without requiring offshore hybrid assets to be defined in legislation because transmission assets between wind farms may be classed as interconnectors. However, as highlighted below, these two concepts (i.e. offshore hybrid assets and interconnectors) should be developed in parallel before a final decision is made. Finally, it must be emphasized that the integration of a flow-based market model for offshore grids with many offshore bidding zones in the current pan-European market coupling algorithms might impact the computational performances.

CREATE A ROBUST LEGAL DEFINITION OF OFFSHORE HYBRID ASSETS

An offshore hybrid asset combines the connection of OWFs with the interconnection between multiple countries. They are the building blocks of the MOG and, by enabling a connection to be multi-functional, have the potential to reduce the total length of offshore cable required to connect a given level of generation capacity.

Under the current market model, whereby the market price for offshore wind is determined by the EEZ in which it is situated, a legal definition of an ‘offshore hybrid asset’ is necessary at both an EU and international level in order to distinguish MOG assets from locally connected wind farms and interconnectors between countries which have their own legal definitions and regulatory frameworks.

Indeed, the absence of a definition for hybrid assets increases the risk that infrastructure would not be used efficiently, and that 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. However, the offshore hybrid asset definition does not yet provide the legal certainty needed for the construction of an offshore grid (under the current market model), as it only creates an exemption 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 definition of ‘offshore hybrid asset’ should be progressed by adopting it 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. This regulatory approach could be tested on a pilot project.

This should be developed in parallel with further studies on the small bidding zones market model, to ensure there is a well-developed alternative plan, should the small bidding zones approach be impractical. Both the ‘offshore hybrid asset’ definition and the small bidding zones model, aim to efficiently use infrastructure and encourage deployment of offshore wind.

In the long term, international consensus on the definition of an 'offshore hybrid asset’ and the extent of jurisdiction states have for hybrid assets would provide greater legal certainty to all MOG connected countries, both inside and outside the EU. PROMOTioN therefore recommends that a common agreed definition of ‘offshore hybrid asset' is included in the mixed partial agreement mentioned above. The level of detail to be defined in the definition of ‘offshore hybrid asset’ will be dependent on the market model adopted.

DEVELOP LONG-TERM PROJECT PIPELINES AND STREAMLINE THE PLANNING PROCESS

Planning and permitting procedures are perceived as a key risk in large infrastructure projects and can cause offshore infrastructure projects to be delayed by several years. A long-term view of proposed offshore wind projects would increase the likelihood of the transmission network being constructed and utilised efficiently. Using a zoned or single-site approach for marine spatial planning, whereby planning authorities select zones or specific sites for offshore wind farms can help create long-term predictability. In addition, a streamlined and preferably common/aligned permitting process will be necessary to deliver and connect these offshore wind projects in a timely manner. PROMOTioN makes the following recommendations with regards to planning:

- **Streamline and align the permitting process to reduce the risk of legislative change during project development.** In addition, 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 the cable permitting process, but coordinate the projected commissioning dates**. This principle will also become increasingly relevant in multi-terminal and 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**. This applies to single- and multi-jurisdiction projects, for both OWF and grid development
- **Move towards joint Environmental Impact Assessments (EIAs) for cross border projects, initially through a pilot project.** The criteria for EIAs and for mitigation measures differ per country and EIAs have to be made on a national level[7]. 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. 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.
- **Allow for technology-agnostic planning**: The development and planning process for offshore transmission assets can take a number of years. By including some flexibility within planning permits to allow for technology developments, projects can deliver the most cost-effective solution available at the point the design is finalised, not at the point planning permission is first applied for[8].

AUTHORISE APPROPRIATE ANTICIPATORY INVESTMENTS

The decision to allow anticipatory investments must weigh up the potential cost saving of the anticipatory investment (compared to the cost of incremental expansions) with the likelihood that the anticipatory investment will be utilised. Several aspects of building a meshed offshore grid may require an anticipatory investment, from building an (initially) oversized platform or transmission cable, to investing in an artificial hub to accommodate future OWF deployments. The certainty provided by allowing anticipatory investment complements the improvements in the Planning and Permitting processes set out above.

Remuneration for cross-border anticipatory investment asset owners should be decided by the meshed offshore grid regulator (possibly a cooperation of a selection of National Regulatory Authorities, NRAs). The rate of remuneration and return on investment should balance the obligation to provide cost-effective networks for consumers, with the need to make transmission assets a viable investment.

Specifically, PROMOTioN recognises that for a grid to develop, platforms soon to be built and installed should be ready for expansion. This will facilitate the positioning of DCCBs where necessary and/or an additional Direct Current (DC) cable connection. This requires anticipatory investment and regulatory approval of this. The initial approval for an extendible platform has been approved for the Ijmuiden Ver project, which anticipates a later connection to the UK or other platforms.

ENABLE NATIONAL REGULATORY AUTHORITIES TO COOPERATE TO REGULATE THE OFFSHORE GRID

The MOG will need to be regulated by a single entity or through cooperation of relevant NRAs. After examining all options, PROMOTioN recommends that the regulatory structure of the MOG should be set through the cooperation of the bordering 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

[7] 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.
[8] Note: the standards and harmonization should be driven by Grid codes and other technical interoperability constraints, rather than specific proposals for a grid element.

acceptable than setting up a new MOG-wide institution whilst still delivering the benefits of a coordinated approach. These NRAs should agree on transmission tariffs paid by OWFs, the revenue paid to transmission owners, incentives for innovation, the process for (and cost of) connecting to the MOG and operational requirements such as safety standards and day-to-day operational rules. Most importantly, these NRAs should set up agreements on how benefit (and cost) sharing can be achieved. Such cooperation can evolve over time, if coastal states are willing to increase the amount of cooperation. Note that this proposal is largely in line with proposals already made in the Clean Energy Package 2018, albeit this is intended to steer the onshore grid, and some aspects may require review for the new offshore situation.

DEVELOP GRID-WIDE SUPPORT SCHEMES FOR OWFS

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.

Whilst support schemes for OWFs are still in place, cooperation mechanisms for renewable support could overcome potential barriers. 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” to countries that are unable to reach their targets.
- **Joint Projects**: An agreement between two or more countries to jointly development renewable energy projects.
- **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.

PROMOTioN 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.

ENSURE SUFFICIENT INVESTMENT CAN BE ACCESSED

Delivering sufficient transmission infrastructure to evacuate projected offshore wind generation and meet interconnection demands will require several billion euros of investment over the next 30 years. Financing models may need to accommodate different types of investors and different financial structures. Financing investment from the balance sheet or through public funds alone will probably not be practicable.

PROMOTioN recommends that several different financing structures may be adopted to enable diverse sources of finance to invest in transmission assets. Special Purpose Vehicles (SPVs) for individual transmission projects and/or broadening ownership of transmission assets allows additional finance to be raised whilst reducing the risk to the parent company.

DEVELOP CONSISTENT DECOMMISSIONING GUIDELINES FOR OFFSHORE ASSETS

To provide consistency on guidelines for decommissioning of offshore wind assets (turbines and offshore grid assets), guidelines should be agreed upon at an international level such as International Maritime Organisation (IMO) or OSPAR[9]. To inform this, further research into the environmental impact of decommissioning OWFs and offshore electricity cables is necessary.

GOVERNMENT RECOMMENDATIONS

ENSURE THE QUALITY AND QUANTITY OF 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 that will be needed by the industry.

SUPPORT THE ESTABLISHMENT OF A 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 support to support investment in key supply chain assets could enable this.

TECHNOLOGY RECOMMENDATIONS

PROJECT AND PLANNING COORDINATION

The responsibility of coordinating/planning projects and allowing the anticipatory investments for multi-terminal extension lies with international associations such as DG Energy, ENTSO-E, ACER, national governments, national regulating authorities, Transmission System Operators (TSOs) and developers. Many of the aspects which need to be coordinated could and should be part of a North Sea Treaty, as described in Section 4.2.1.2, and be registered in a TYNDP-like process.

UPDATE SYSTEM OPERATION GUIDELINES

The current system operation guidelines are intended for the interconnected AC transmission network. It is very unlikely that international multi-actor HVDC networks will be realised in the absence of similar regulations to include the specifics of interconnected HVDC transmission networks. It is strongly recommended to prioritise updating the ‘Regulation (EU) 2017/1485 — guideline on electricity transmission system operation’ to include specific HVDC guidelines and definitions.

ENABLE MULTI-PURPOSE INFRASTRUCTURE USE

In all concepts that allow meshing, the topology will evolve gradually from a few multi-terminal connections to a more complex topology. Eventually, a backbone will interconnect several multi-terminal connections. 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 and multi-terminal connections. The technical HVDC systems necessary for wind power evacuation and interconnection may have different

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

technical and functional requirements. It is therefore recommended to ensure technical compatibility for both types of use and enable the future hybrid interconnection in cases where this is economically efficient i.e. when two OWFs are in the vicinity of each other.

UPDATE TYNDP PROCESS TO IDENTIFY BENEFICIAL MULTI-TERMINAL GRID EXTENSIONS

To date, potential multi-terminal HVDC grid extensions have often not been realised, not due to the immaturity of technology, but due to the incompatibility of regulatory frameworks, project purpose and governance, project ratings and project planning. The main benefit of MOGs compared to multiple point-to-point connections of offshore wind is the combined use of infrastructure for different purposes, thereby increasing asset utilisation, reducing losses and improving availability. In order to be able to exploit this possibility, coordination between different project proposals for offshore HVDC infrastructure is necessary at an early stage so that potential synergies between projects can be identified and evaluated fully.

Notification of proposals for new HVDC transmission infrastructure should be mandatory between the North Sea states in order to create transparency in project planning. The requirements and process for notification should be described in a North Sea treaty (as recommended above). A process similar to, or even fully integrated with, the TYNDP may be developed.

ESTABLISH HUBS IN PLACES WITH HIGH WIND ENERGY GENERATION DENSITY

As shown in the CBA (Deliverable 12.2), artificial islands with a large capacity to collect and distribute energy are expected to be a more cost-effective solution than individual HVDC platforms. The OWF capacity at which artificial islands become the preferred solution is variable and dependent on multiple factors, such as the position of connected OWFs relative to the island and its onshore connection point. PROMOTioN has not analysed the optimal size of an island (this is probably dependent on spatial planning and different for each proposed island). However, the analysis of the Low wind scenario indicates that relatively small islands of <10 GW hosting capacity seem to have no or limited financial benefit. With a long lead time anticipated for obtaining the right to construct an artificial island, any islands have to be planned well in advance.

Several options for connecting the converters on the island have been considered in PROMOTioN, but have not been studied in further detail. It is therefore recommended to study potential designs of the artificial islands in more detail, including different interconnection options of the converters and the option to install flexibility assets (electrical storage or Power-to-X conversion) on the island.

ALLOW THE APPLICATION OF ANTICIPATORY INVESTMENTS IN THE GRID

In the early phases of evolution of multi-actor and multi-national multi-terminal HVDC grids, the acceptance and approval of anticipatory investments is of paramount importance. PROMOTioN thus recommends National Governments and the EU to investigate the possibilities, conditions and legal frameworks for enabling anticipatory investments and allocate adequate funds and incentives for doing so.

TOPOLOGICAL COMPATIBILITY

HVDC projects can only be connected as a multi-terminal extension if several basic, technology-, vendor- and TSO independent technical requirements are met. Short-term international collaboration and coordination on the topological technical requirements is of paramount importance if HVDC grid elements developing in different locations are to be compatible with one another for future connection. Several aspects will have to be coordinated all at once; these are set out in this section.

STANDARDIZE RATED HVDC VOLTAGES

Power systems operating at different voltage levels (in steady-state and transient conditions) cannot be directly coupled to form one interconnected grid without either loss of performance (derating) of one system or additional Capital Expenditure (CAPEX) (upgrading) invested in the other. In the absence of cost-effective DC-DC converters, a common rated HVDC system voltage must be agreed on. In PROMOTioN, a common voltage level of 525 kV has been assumed for projects in the North Sea, and 320 kV for future projects in the Irish Sea. A final choice of rated voltage should be based on a comparative CBA taking into account full lifetime costs of the offshore grid.

COORDINATE CONVERTER CONFIGURATION

HVDC systems can be configured in monopolar and bipolar arrangements, as explained in Appendix II. From a system perspective, the main difference between monopole and bipole systems is the loss of capacity in case of a pole fault, which is 100% in case of a monopole and 50% in case of a bipole (with dedicated metallic return). While theoretically it is technically possible to connect different converter configurations together into one HVDC power system, this will complicate several aspects, like the previously discussed differences in voltage ranges. Moreover, the behaviour under pole-to-ground faults changes due to the different earthing points leading to a change in system design for short circuit conditions. It is recommended to coordinate the choice of converter configuration and any resulting physical ratings at an early stage of offshore grid development.

COORDINATE SYSTEM EARTHING

The choice of earthing point location determines the voltages at different nodes of the neutral of the HVDC power system, and with that the maximum steady-state pole-earth voltages experienced by the primary equipment. In case of a disconnection of a branch of the HVDC power system which contains the system earthing point, a back-up earthing location should be connected. The location of the system earthing point, back-up locations, and the responsibility to provide earthing should be coordinated and agreed between all parties participating in offshore grid development.

The connection to earth may include an impedance to limit the magnitude of earth fault currents. In symmetrical monopoles, different types of earthing points can be realised. The choice and size of the (equivalent) earthing impedance will affect the magnitude of any overvoltages experienced in the system during faults. Hence, this is closely coupled to the choice of voltage rating and Basic Insulation Level (BIL). It is recommended to coordinate the type and size of the earthing impedance and the method of system earthing.

COORDINATE ANCILLARY SERVICES

Modern HVDC converters are capable of delivering a wide range of Alternating Current (AC) ancillary services such as voltage support, frequency support, black-start functionality and active harmonic filtering. It is recommended to coordinate the need for ancillary services, underlying market models, required technical specifications and necessary additional investments by means of a comprehensive CBA study. Furthermore, new types of ancillary services for DC systems are required to enable an efficient and technology neutral operation of the hybrid AC/DC power system.

ANTICIPATE SPARE BAY AND SPACE REQUIREMENTS

A pre-requisite for multi terminal expansion of existing (offshore) HVDC links is the existence of a physical possibility to host an additional cable connection. Typically, this is referred to as an additional switchgear bay. It is recommended to design offshore platforms with sufficient space to host the equipment necessary for the physical connection of an extension.

STANDARDISE OFFSHORE HVDC PLATFORMS

Within PROMOTioN a choice is made to analyse the development of the offshore grid with amongst others the currently novel 525-kV, HVDC equipment where applicable. The analysis in Deliverable 12.2 concludes that 525-kV 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, as the standardised concept may then be applied throughout the entire area. Standardisation of the technologies will require first a deployment of multiple 525kV offshore HVDC hubs, after which a standardised format may be developed. Within PROMOTioN, the 525-kV 2-GW standardised format is considered throughout the entire period, but with rapid development in technologies in the industry it is assumed that in reality this concept will evolve with time to solutions with higher voltage and/or higher capacity. While this recommendation is steered towards a 525-kV 2-GW HVDC concept (due to the input assumptions made), the recommendation to standardise equipment and infrastructure is valid for other sizes as well.

FUNCTIONAL COMPATIBILITY

ESTABLISH AN (OFFSHORE) HVDC NETWORK CODE

To facilitate the interconnection of multiple HVDC systems to one multi-terminal systems, a set of functional specifications has to be derived, which ensures the compatibility and interoperability of the different components and especially the converters in a DC grid. Such functional specifications are typically set in grid codes. However, existing Grid Codes for HVDC systems specify requirements at the AC point of connection, but have not yet targeted the DC point of connection. In a first step, DC systems were seen as addition to the existing AC transmission grid and the prevailing of single point-to-point links did not yet require corresponding requirements at the DC point of connection. It is recommended to start work on developing and adopting a legally binding DC system network code as soon as possible. Ideally there would be one set of specifications at the DC point of connection in an HVDC grid code, that is applicable regardless of the country to facilitate the coordinated development of a multi-national offshore grid.

ENSURE STABLE OPERATION AND CONTROL OF THE MESHED OFFSHORE GRID

The operation of HVDC grids and any connected offshore AC grids is governed by the characteristics of the converter and the offshore wind turbine and wind farm control systems. The overall system operation therefore needs a central grid control which defines the load flow by setting the control modes, limits, ramp rates and corresponding set points - otherwise the HVDC system will not operate. The operational routines and set points for a DC grid are different from an AC grid, so for the HVDC grid new functions in the “central grid controller” are needed. It is recommended to initiate work on analysing, specifying, designing and demonstrating central grid control, as well as on methods to test it, and frameworks for its governance.

CHOOSE AND IMPLEMENT AN APPROPRIATE PROTECTION SYSTEM

Several protection strategies are evaluated in PROMOTioN. Different fault clearing strategies are characterised by the type and number of HVDC circuit breakers, the locations of HVDC circuit breakers and the type of converters. It is recommended to determine and coordinate the limits to interoperability and any necessary required additional investments to realise interoperability between HVDC transmission systems with different fault clearing strategies, and how any differences can be captured in a technology neutral way in the offshore HVDC system network code.

VENDOR INTEROPERABILITY

ENSURE STABILITY OF CONTROL

Different implementations of digital control systems with the same functional specifications may in some cases lead to unstable behaviour or a loss of performance when they are connected in the same HVDC transmission system. Identifying and solving or mitigating interactions between the control systems due to resonances in and with the system at an early stage is in most cases the most cost-effective way. This can be done through a series of analyses starting with offline simulations. This may be best realised with open or "grey-box" models, which allow for transparent interoperability. However, it may be achieved using the black-box models supplied by vendors and finally validating this by means of hardware-in-the-loop simulations with the actual control & protection replicas of both vendors' systems. It is recommended to standardise the methods for qualifying dynamic performance of multi-vendor HVDC transmission systems.

STANDARDISE COMMUNICATION INTERFACES

Today, most HVDC converter & equipment vendors use their own in-house developed digital communication systems. These are not typically interoperable with one another. The ability of different elements in an HVDC transmission system to communicate i.e. to exchange data and to use the exchanged data, is a pre-requisite for the development of an offshore grid. It is recommended to fully standardise the communication interfaces between equipment of different vendors.

STANDARDISE MECHANICAL INTERFACES

It is recommended to develop standardized interfaces for primary and secondary equipment of different vendors. These standards should include requirements for at least the following aspects: Dimensions, Forces, Materials, Thermal aspects, Required space for installation. The standards should include procedures for how compliance with the requirements should be qualified and demonstrated.

CONTRACTUAL COMPATIBILITY

Different TSOs and developers procure HVDC transmission systems in different ways, often reflecting the risk appetite, in-house experience and financing structures they have. Traditionally, European point-to-point HVDC transmission systems have been procured from EPC (Engineer, Procure and Construct) contractors in which the scope of supply may have been divided into a high-level granularity of both converters (hardware and complete control & protection) and line/cable. The functional requirements of the HVDC link were mostly specified at the AC interfaces of the converters where existing AC grid codes would apply, and performance warrantees regarding project delivery and operational aspects such as losses and availability were agreed. The paradigm change to organic step-wise HVDC grid development requires a different approach towards the procurement of HVDC transmission systems and a much greater role for the purchaser (TSO or developer). It is recommended to develop a best practise or guideline which can be followed to ensure that procurement choices do not exclude future expansion of HVDC transmission systems. The following aspects, among others, should be considered:

- Terminology & definitions – Different vendors sometimes use different (often product branding) terminology for the same components or functions. This may be confusing or misleading in multi-vendor settings and it is recommended to update existing standard terms and definitions to include multi-terminal HVDC grid aspects. A good basis is the technical specification developed by CENELEC (European Committee for Electrotechnical Standardization) 50654 [4], it is recommended to start using this in real HVDC projects as soon as possible to gain experience and fine-tune/mature the specification.
- Procurement strategy – The development of an HVDC transmission systems consists of different main hardware elements and different development phases which could be supplied by different vendors in an effort to get a more competitive tendering. An increasing number of interfaces will lead to increased risk and an increased effort required from the TSO to manage this. It is recommended to ensure that the choice of procurement strategy in one project does not lead to undue or excessive risk management effort for a future extension of that grid.
- System integration responsibility – A procurement strategy should clearly indicate which party is responsible for the system integration. The allocation of this role should not lead to contractual barriers in the context of stepwise offshore grid development. It is thus recommended to study different possibilities and their pros and cons as a guideline for purchasers of HVDC equipment.
- Completeness of requirements – In specifying grid extensions, it is important to have a common understanding of the level of detail, nature and number of requirements to ensure that a balance is struck between what is necessary to enable grid extension, but leave sufficient room for innovation and cost reduction. The CENELEC technical specification could for example be used as a reference.
- Exchange of information – The exchange of information between vendors which is required to enable the successful operation of their equipment in one HVDC transmission system must be enabled and thus formally determined in the contract. This is relevant for equipment that is anticipated to be extended in the future as well as new equipment. It is recommended to develop a guideline or even standard for the parameters, models, interface definitions, and other information which needs to be exchanged as a minimum, the format the timing of the exchange and the method of exchange. This is especially relevant for aspects which have not yet been standardized.
- Warranties, liabilities and conflict resolution – Typically manufacturers give warranties on performance (e.g. losses and availability) and project delivery which are contractually linked to fines and sometimes bonuses if these warranties are broken or met, respectively. The extension of existing infrastructure could affect the contractual requirement of one manufacturer to satisfy these warranties outside his control. To avoid undue penalties or bonuses, it is recommended to take grid extension into account in the formulation of the warranties in the procurement phase. Similarly, clear guidelines should ideally be established on how liability in case of a multi-vendor system should be established and what type of measurements and logs should be kept in order to do so. For any cases that fall outside these guidelines, it is recommended to develop and commonly adopt conflict resolution models.
- Technology qualification, testing & facilities – In a multi-vendor and multi-actor system, the performance of the whole system, and thus the benefit to a user of the system, relies on the performance and quality of individual parts of it. To ensure a minimum level of performance, all technology used in the system should be qualified to a minimum standard agreed between all users

of the system. This applies to the level of Quality Assurance (QA)/ Quality Control (QC) applied during fabrication, the tests done to prove technology meets the requirements, and the type of facilities these tests should be carried out in (capability to recreate suitable physical and functional stresses, and independence are aspects to consider). It is recommended to agree on a common set of technical standards for use in the development of the HVDC grid, to carry out a gap analysis on the scope of currently existing standardisation and to initiate technical standardisation activities in missing disciplines.

FURTHER RESEARCH, DEVELOPMENT & DEMONSTRATION

The PROMOTioN consortium is of the opinion that from a technical perspective there are no fundamental showstoppers towards the development of meshed multi-terminal offshore HVDC grids. However, several fields of further research have been identified that may lead to more cost-effective, environmentally friendly, optimally integrated and increased functionality development and usage of the multi-terminal and meshed offshore HVDC grid.

INITIATE FULL-SCALE MULTI-VENDOR, MULTI-PURPOSE, MULTI-TERMINAL HVDC NETWORK PILOT

Individual technology elements have been demonstrated to have achieved sufficient maturity for deployment in real HVDC grids. The integration of these technology components into one functioning system has only been shown by demonstration, and even though there is no doubt that it is technically possible, many issues with regard to multi-vendor implementation remain to be addressed. To achieve this and install the confidence in the technology, the PROMOTioN consortium recommends the development of a full-scale pilot, which, procured on a commercial basis through competitive tendering, not only demonstrates the technology maturity but also realises the potential benefit of multi-vendor, multi-purpose multi-terminal HVDC network solutions, compared to their point-point counterfactual case. PROMOTioN has identified and analysed several potential sites in north-west Europe that could be suitable for such a pilot. The analysis has been further described under the short-term projects section.

EXPLORE THE NEED FOR FLEXIBILITY IN THE SYSTEM

The availability of flexibility options, in particular energy storage, at the onshore hosting points has a strong effect on the ability to realise offshore grid integration synergies. Increasing onshore hosting capacity significantly reduces the total cable length required for all concepts but is more beneficial for the multi-terminal and meshed grid concepts, than the ‘Business As Usual’ purely point-to-point connected concept. 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 not only 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 due to onshore grid congestion or low demand. It is also structural curtailment. For these reasons it 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. It is recommended to carry out an integrated offshore grid planning study, taking into account onshore AC grid constraints and options for flexibility.

INTEGRATED AC/DC SYSTEM STUDIES

The PROMOTioN physical scope has been conveniently limited to the onshore landing points of the offshore HVDC grid. It is however clear the integration of large amounts of power delivered by the offshore HVDC grid into the existing onshore AC grid is a formidable challenge, and will have strong influence on the topology and functionality of the offshore HVDC grid. The ability of AC grids to host the HVDC connections points is limited due to capacity constraints, constraints due to changing technology, constraints due to changing behaviour and roles of grid users. System integration, in the widest sense of the word, considering the path from generator to consumer, is the key aspect. Whereas EU projects such as PROMOTioN and BestPaths have delivered technical and regulatory solutions for HVDC grids, and MIGRATE and GARPUR have focused on the evolution of AC grids, it is highly recommended to initiate research and development considering the system integration of large-scale pan-European HVDC grids into the incumbent but rapidly changing AC grids.

New tools and modelling approaches for representation of large HVDC systems and integrated system studies need to be developed. Currently, time domain grid integration studies of HVDC systems can take many hours to run per scenario, many scenarios need to be considered, and the results are evaluated by hand to determine if operation is for example grid code compliant. The sheer amount of processing time required makes it almost impossible to do so for a large integrated grid. New simulation approaches, automated evaluation, and new modelling techniques should be developed in order to study the interaction between AC and DC systems for different time frames and contingencies and thereby facilitate the integration of large HVDC grids into existing AC grids.

Successful operation of integrated HVDC and AC grids will require the development of control and communication concepts for integrated system operation. The real-time dispatch of variable renewable energy sources, storage and ancillary services should integrate vertically through the different layers of European and national transmission as well as distribution and take into account the ability of consumers, variable energy sources and storage options in different levels of the power system to contribute to system stability. In addition, the coordination should be integrated horizontally between different countries and users of the power system, fully utilising the possibilities offered by automated digital control systems. Next to developing the technical solutions, research should be initiated regarding the governance and regulation of the integrated power system operation i.e. which party owns and operates the different power system operation aspects and what market models can offer an appropriate risk-reward balance.

OFFSHORE WIND FARM ADVANCED CAPABILITIES

Offshore wind farms are envisaged to take up a significant share of the future generation mix and thereby replace conventional generation. PROMOTioN has shown that the ancillary services of conventional power plants such as reactive power support, power oscillation damping, frequency support and black start operation can in principle also be delivered by HVDC connected offshore wind farms. To realise these abilities will require modifications to turbine and converter control systems, auxiliary power supply arrangements and the system control and communication systems. It is recommended to carry out further research, development and demonstration work on how to realise, qualify and further enhance offshore wind farm ancillary service technologies, and crucially, how to integrate them into the offshore HVDC grid and the wider AC/DC power system.

HVDC HUB TOPOLOGY

PROMOTioN did not study different types of HVDC hub implementations and their pros and cons in great detail. When implementing hubs, different designs with respect to the number of and type of bus bars, and the number and connection of HVDC circuit breakers can be adopted that have different impacts on the level of redundancy and selectivity of fault clearing. It is recommended to carry out a full lifecycle costs and benefits analysis to determine the applicability of AC vs DC hubs in different scenarios. Furthermore, it is recommended to establish technical design considerations for DC hubs, especially in the light of power system redundancy requirements and protection.

DC SWITCHGEAR DEVELOPMENT

Further development of HVDC switchgear is foreseen to be necessary in order to improve reliability, improve operation, reduce environmental impact and reduce costs.

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). This 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, demonstrating their long-term viability whilst offering solutions for the often vendor-specific operation and maintenance aspects of these different alternative gases. In addition, several key components which are necessary for offshore HVDC grid development such as high-speed switches and pre-insertion resistors do not currently exist as gas insulated components. Similarly, test requirements and procedures for these components need to be developed and standardised. 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 a commercial application at 320 kV and a full scale pilot at 525 kV.

With regard to HVDC circuit breakers, several prototypes have been developed and PROMOTioN has demonstrated that the technology is in principle ready for application. However, due to the use air insulated components in many HVDC circuit breaker technologies, and due to the sheer number of components required, they are typically rather large devices and require a substantial footprint. Offshore, this footprint comes at a significant cost which hampers the uptake of these devices. It is recommended to carry out further research on HVDC circuit breaker topologies with the aim of reducing their cost and footprint. Potential avenues are the use of gas insulated components, novel types of valves, improving speed of operation, etc.

INTEROPERABILITY OF CONTROLS AND PROTECTION

Interoperability between control and protection systems, particularly when supplied by different vendors, is seen as a significant hurdle towards HVDC grid development. This concerns pre-dominantly the communication interfaces, but also mechanical and electrical interfaces and dynamic performance. It is recommended to focus significant effort onto standardisation activities that address these issues and carry out further research on control & protection strategies that are less prone to issues due to different vendor implementations. Examples of such approaches are the open-source implementation (and licencing) of control & protection layers of converters that have an impact on the system behaviour (i.e. upper level controls).

RESEARCH THE NEED FOR DC/DC CONVERTERS IN THE SYSTEM

A major obstacle to connecting HVDC grids with different voltage levels is the absence, low technology maturity and potential cost of DC-DC transformers. Currently, a DC-DC conversion would need to be done using a back-back DC-AC-DC conversion, similar to frequency converters between different synchronous AC zones. This makes it costly to connect HVDC grids with different voltage levels and optimise those for a class of power ratings and transmission distances. Furthermore, DC-DC converters may be a necessity in more complex multi-terminal and meshed HVDC grids to control power flows.

Research, development and demonstration into cost-effective options for HVDC to HVDC conversion is thus essential. 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 2050.

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 necessary. When each recommendation is necessary is based on the development of the grid topologies of Deliverable 12.2 over time. For each of the periods below, a short description of the roll-out is included.

An indication of the time required to implement each of the recommendations is given. 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.

THE PERIOD 2020 – 2030

Out to 2030, roll out of offshore transmission largely follows current practices, except for the use of 525-kV 2-GW HVDC components (not yet deployed in 2020) and the need for anticipatory investments. However, many of the technological recommendations should already be implemented in order to allow the grid to naturally evolve into an offshore grid with multi-terminal and meshed elements. In order to allow a multi-purpose, multi-actor, multi-vendor, multi-national MOG to develop, the assumption of compatibility needs to be turned into reality through the formulation of a set of explicit technology and purpose-agnostic minimum requirements which all actors in the MOG development need to adhere to. Therefore, even in the early stages of grid development, the key technology recommendations will be required to be implemented. For example, the establishment of an offshore HVDC network code and alignment on HVDC system ratings can facilitate meshing of the grid in later periods as it will allow grid developers to independently develop the offshore grid according to similar characteristics. Many of the technology recommendations should be implemented as soon as possible. In our prognosis we construct island hubs early on. Due to a long regulatory lead-time up to the construction of an island hub, this is optimistic. The first hub may only be operational by 2030 at the earliest, with only a short period between construction and operation once the regulation is settled.

As much of the offshore grid development in this period is similar to the current offshore grid practices, many of the same regulations can still apply in this period. However, a pilot project to test the small bidding zones model should be established and a decision made about its wider rollout. Additionally, due to some locally multi-terminal and meshed configurations, anticipatory investments should be allowed in some North Sea countries, where there is a high degree of certainty that neighbouring windfarms or interconnection will be constructed.

The planning of offshore wind generation sites will require a more extensive planning and coordination to gain maximum benefit from potential meshing and or large hub or islands. This may need to be delegated to smaller groups to have more goal directed and pragmatic action. This should also bridge to a strengthened role for umbrella organisations such as ENTSO-E and ACER to coordinate improved coordination between bottom-up short term plans and longer term system plans. This should also implement a coherent regulatory environment.

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 the EEZ in which 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.

Finally, 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, the progress made and the concerned stakeholders is presented in Table 1 below.

Table 1- Actions, their timing and the stakeholders in the period 2020 – 2030. (Prep = Start Preparations, Impl = Start Implementation, Nec = Necessary by).

ACTION	PREP	IMPL	NEC	PROGRESS	EXPLANATION	IMPLEMENTER	INFLUENCER	USER
North Sea Treaty: Develop a Mixed Partial Agreement for Regional Cooperation	2020	2025	2030	None	Required content identified in PROMOTioN but no progress on drafting of a treaty.	EC and National Governments	EC, National Governments, NRAs, Transmission Owners and OWF developers	NRAs, TSOs and OWF developers
Market model trials: Carry out pilot and decide on introducing the small bidding zones market model	2020	2024	2025	Final	The small bidding zones model is consistent with the EU's Clean Energy Package but a trial project is needed to test its practicality.	NRAs	EC, National Governments, TSOs and developers, System OWF developers	TSOs and developers, OWF developers,
Market model implementation: Introducing the small bidding zones market model	2025	2027	2030	Final	No change in transmission asset regulation required, changing the market setup requires some time.	NRAs	OWF Developers, TSOs, NRAs, Governments, EC	Utilities, TSOs
Offshore hybrid asset: Create a robust legal definition of Offshore hybrid assets	2020	2028	2030	Ongoing	There is a definition in the Recitals of the Electricity Regulation, but a detailed approach to regulating these assets has not been implemented. This should be developed in parallel with market model solutions.	EC (Short-Term), EC and National Governments (long term)	EC, National Governments, NRAs, Transmission Owners and OWF developers	NRAs, TSOs and OWF developers
Project Pipelines: Develop long-term project pipelines and streamline the planning process	2020	2025	2030	Ongoing	Although implemented in the North Sea states separately, there is no alignment yet among the states.	EC, NRAs	OWF Developers, TSOs, NRAs, Governments, EC	TSOs, OWF developers
Anticipatory investments: Authorise appropriate anticipatory investments	2020	2022	2025	Ongoing	Decisions on anticipatory investment are taken at a national level	Governments (in some cases delegated to NRAs)	Transmission Owners and Operators, NRAs, OWF Developers	TSOs, OWFs
Grid Regulation: Enable National Regulatory Authorities to cooperate to regulate the offshore grid	2020	2025	2030	Ongoing	Concept of Regional Cooperation Centres in place, but no decision on who regulates a MOG.	NRAs	EC, National Governments, NRAs, ACER (Coordination)	NRAs, TSOs, OWF developers

ACTION	PREP	IMPL	NEC	PROGRESS	EXPLANATION	IMPLEMENTER	INFLUENCER	USER
Investment models: Ensure sufficient investment can be reached	2020	2025	2027	Ongoing	In progress – allowed in some countries.	TSOs, National Governments, NRAs	TSOs, National Governments, Financial institutions, NRAs, Consumer Groups	TSOs, Financial Providers
System operation guidelines: Update system operation guidelines	2020	2022	2023	Ongoing	Research started within PROMOTioN. As early implementation can facilitate multi-terminal and meshing in later periods, this recommendation should be implemented as soon as possible.	DG Energy, ENTSO-E, ACER, national governments, national regulating authorities, TSOs and developers		TSOs and developers
Multi-purpose infrastructure: Enable multi-purpose infrastructure use	2020	2023	2025	Ongoing	Research started within PROMOTioN. As early implementation can facilitate meshing in later periods, this recommendation should be implemented as soon as possible.	DG Energy, ENTSO-E, ACER, national governments, national regulating authorities, TSOs and developers		TSOs and developers
TYNDP process: Update TYNDP process to identify beneficial multi-terminal grid extensions	2020	2023	2025	Ongoing	Research started within PROMOTioN. As early implementation can facilitate meshing in later periods, this recommendation should be implemented as soon as possible.	DG Energy, ENTSO-E, ACER, national governments, national regulating authorities, TSOs and developers		TSOs and developers
Hubs: establish artificial islands in places with high wind energy generation density	2020	2025	2030	Ongoing	Research started within PROMOTioN. As early implementation can facilitate meshing in later periods, this recommendation should be implemented as soon as possible.	DG Energy, ENTSO-E, ACER, national governments, national regulating authorities, TSOs and developers		TSOs and developers
Anticipatory investments: Allow the application of anticipatory investments in the grid	2020	2025	2027	Ongoing	Research started within PROMOTioN. As early implementation can facilitate meshing in later periods, this recommendation should be implemented as soon as possible.	DG Energy, ENTSO-E, ACER, national governments, national regulating authorities, TSOs and developers		TSOs and developers
Topological compatibility: Ensure the implementation of the recommendations that lead to topological compatibility	2020	2022	2025	Ongoing	Research started within PROMOTioN. As early implementation can facilitate meshing in later periods, this recommendation should be implemented as soon as possible.	DG Energy, ENTSO-E, ACER, national governments, national regulating authorities, TSOs and developers		TSOs and developers

ACTION	PREP	IMPL	NEC	PROGRESS	EXPLANATION	IMPLEMENTER	INFLUENCER	USER
Offshore HVDC network code: Establish an offshore HVDC network code	2020	2022	2025	Ongoing	Research started within PROMOTioN. As early implementation can facilitate meshing in later periods, this recommendation should be implemented as soon as possible.	ENTSO-E	ACER, TSOs and developers, manufacturers and standardisation bodies	TSOs and developers
Stable operation and control: Ensure stable operation and control of the Meshed Offshore Grid	2020	2022	2025	Ongoing	Research started within PROMOTioN. As early implementation can facilitate meshing in later periods, this recommendation should be implemented as soon as possible.	TSOs and developers	Manufacturers, OWF developers	TSOs and developers
Vendor interoperability: Implement the recommendations that lead to vendor compatibility	2020	2022	2025	Ongoing	Research started within PROMOTioN and EC. As early implementation can facilitate meshing in later periods, this recommendation should be implemented as soon as possible.	ENTSO-E, TSOs and developers	Manufacturers, OWF developers	TSOs and developers
Contractual compatibility: Develop a best practise or guideline to guarantee contractual compatibility	2020	2025	2027	Ongoing	Research started within PROMOTioN	ENTSO-E, TSOs and developers, NRAs	Manufacturers	TSOs and developers

THE PERIOD 2030 – 2040

As the rate of grid development increases over this period, the solutions for the control systems and DCCBs necessary for protection should be ready for deployment. Additionally, interoperability issues and multi-vendor integration of infrastructure should be understood. 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 the further studies of the small bidding zones market model are successful, they should be rolled out more widely during this period. The alternative is to progress with the development of a regulatory regime for offshore hybrid assets.

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, and potentially the introduction of small bidding zones, the remuneration of offshore wind farms 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. The recommendations to the stakeholders and their progress are presented below in Table 2.

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 multi-terminal and meshed grids to create a highly complex multi-terminal and meshed grid. Research on decommissioning impacts should lead to the development of guidelines for OWFs and transmission infrastructure in this period, if not before. This action is presented in Table 3 below.

THE PERIOD 2020 – 2050

Some recommendations will run from the start up to the end of the analysed period. This includes the research on protection systems and all recommendations included in the technology section on further research, development and demonstration. The recommendations, their timing and the stakeholders are presented in Table 4 below

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Table 2 - Actions, their timing and the stakeholders in the period 2030 – 2040. (Prep = Start Preparations, Impl = Start Implementation, Nec = Necessary by).

ACTION	PREP	IMPL	NEC	PROGRESS	EXPLANATION	IMPLEMENTER	INFLUENCER	USER
Skilled personnel: Ensure the quality and quantity of skilled personnel	2025	2035	2035	Ongoing	No specified programs for HVDC transmission implemented.	Governments	Schools/Universities/Supply Chain/ TSOs/OWF developers	Supply Chain/ TSOs and developers
Supply chain: Support the establishment of a supply chain	2030		2035	Ongoing	Although there are European manufacturers, there is no specific supply chain set up.	Governments	Manufacturers OWF developers/ TSOs/ others	OWF developers/ TSOs and developers
Support schemes: Develop grid-wide support schemes for OWFs	2025	2030	2035	Ongoing	The EU has frameworks for joint supports schemes which can be built upon	Governments/ NRAs	TSOs/OWF Developers/ Consumer Groups	OWF developers

Table 3- Actions, their timing and the stakeholders in the period 2040 – 2050. (Prep = Start Preparations, Impl = Start Implementation, Nec = Necessary by).

ACTION	PREP	IMPL	NEC	PROGRESS	EXPLANATION	IMPLEMENTER	INFLUENCER	USER
Decommissioning Guidelines: develop consistent decommissioning guidelines for offshore assets	2020	2045	2045	Ongoing	National Guidelines are in place. Harmonisation required but decommissioning guidelines not necessary in the near future.	IMO or OSPAR	National Governments, OWF Developers, TSOs, Third party construction, NRAs, EC	TSOs, OWF Developers

Table 4 - Actions, their timing and the stakeholders in the period 2020 – 2050. (Prep = Start Preparations, Impl = Start Implementation, Nec = Necessary by).

ACTION	PREP	IMPL	NEC	PROGRESS	EXPLANATION	IMPLEMENTER	INFLUENCER	USER
Protection strategy: Choose and implement an appropriate protection system		2020	2050	Ongoing	The protection strategy can be chosen by each TSO separately, according to PROMOTioN analysis. Which strategy is necessary where is still to be further researched.	TSOs	Manufacturers	TSOs
Further research: Further technological research, development and demonstrations		2020	2050	Ongoing	Further technological research, development and demonstration recommendations will be carried on within the analysed period. These could run up to and even past 2050, or be completed anywhere within the period.	DG Energy, ENTSO-E, TSOs, manufacturers and developers		TSOs and developers, manufacturers

ROADMAP TO A MESHED OFFSHORE GRID

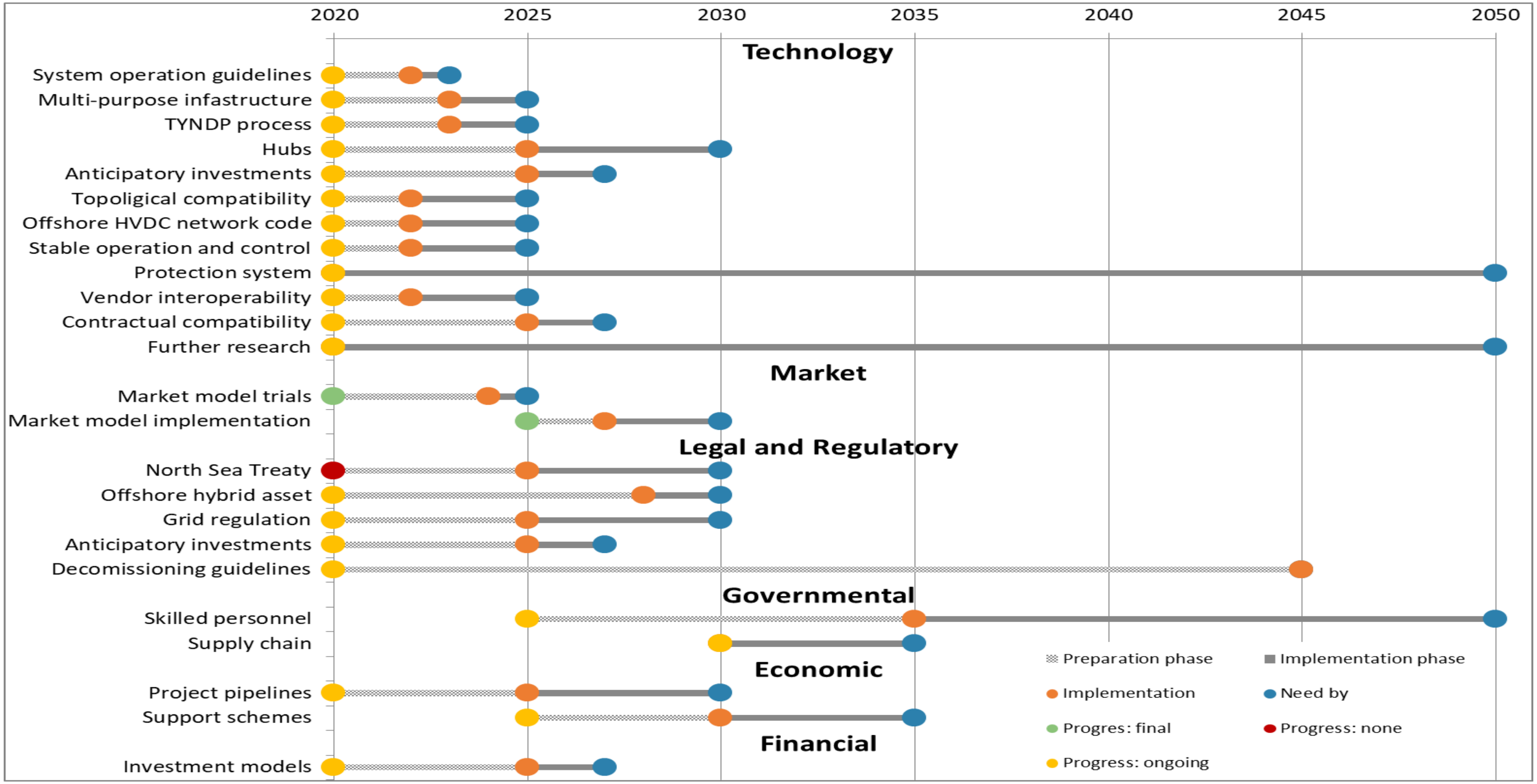


Figure 2- Roadmap to a Meshed Offshore Grid, presenting the recommendations, their progress and their timing.

DOCUMENT STRUCTURE

This report is the culmination of over four years of research into the technical, legal and regulatory, economic, Governmental, market and financial requirements for constructing a Meshed Offshore Grid (MOG) in the Northern Seas. It summarises the findings from the wider PROMOTioN (Progress in Meshed HVDC Offshore Transmission Networks) project. While PROMOTioN has clearly advanced the necessary technologies and understanding of the non-technical issues, there is still a long path to delivering an offshore grid capable of evacuating energy to shore at the scale required to achieve 2050 climate goals. This document presents a roadmap for delivering transmission networks in the North Sea cost effectively and at scale. This document is split into seven chapters followed by appendices:

1. Introduction
2. Cost-Benefit Analysis of a Multi-Terminal Offshore Grid
3. 2020 – 2030: Current development plans
4. Development of a meshed grid

Different TSOs and developers procure HVDC transmission systems in different ways, often reflecting the risk appetite, in-house experience and financing structures they have. Traditionally, point-to-point HVDC transmission systems have been procured from EPC (Engineering, Procurement and Construction) contractors in which the scope of supply may have been divided into a high-level granularity of both converters (hardware and complete control & protection) and line/cable. The functional requirements of the HVDC link were mostly specified at the AC interfaces of the converters where grid codes would apply, and performance warrantees regarding project delivery and operational aspects such as losses and availability were agreed. The paradigm change to organic step-wise HVDC grid development requires a different approach towards the procurement of HVDC transmission systems and a much greater role for the purchaser (TSO or developer). **It is recommended to develop a best practise guideline which can be followed to ensure that procurement choices do not exclude future expansion of HVDC transmission systems**. The following aspects, among others, should be considered:

- Terminology & definitions – Different vendors sometimes use different (often product branding) terminology for the same components or functions. This may be confusing or misleading in multi-vendor settings and it is recommended to update existing standard terms and definitions to include multi-terminal HVDC grid aspects a good basis is the technical specification developed by CENELEC 50654 .
- Procurement strategy – The development of an HVDC transmission systems consists of different main hardware elements and different development phases which could be supplied by different vendors in an effort to get a more competitive tendering. An increasing number of interfaces will lead to increased risk and an increased effort required from the TSO to manage this. It is recommended to ensure that the choice of procurement strategy in one project does not lead to undue or excessive risk management effort for a future extension of that grid.
- System integration responsibility – A procurement strategy should clearly indicate which party is responsible for the system integration. The allocation of this role should not lead to contractual barriers in the context of stepwise offshore grid development. It is thus recommended to study different possibilities and their pros and cons as a guideline for purchasers of HVDC equipment.
- Completeness of requirements – In specifying grid extensions, it is important to have a common understanding of the level of detail, nature and number of requirements to ensure that a balance is

struck between what is necessary to enable grid extension, but leave sufficient room for innovation and cost reduction. The CENELEC technical specification could for example be used as a reference.

- Exchange of information – The exchange of information between vendors which is required to enable the successful operation of their equipment in one HVDC transmission system must be enabled and thus formally determined in the contract. **It is recommended to develop a guideline or even standard for the parameters, models, interface definitions, and other information which needs to be exchanged as a minimum, the timing of the exchange and the method of exchange**. This is especially relevant for aspects which have not yet been standardized.
- Warrantees, liabilities and conflict resolution – Typically manufacturers give warrantees on performance (e.g. losses and availability) and project delivery which are contractually linked to fines and sometimes bonuses if these warrantees are broken or met, respectively. The extension of existing infrastructure could affect the contractual requirement of one manufacturer to satisfy these warrantees outside his control. To avoid undue penalties or bonuses, **it is recommended to take grid extension into account in the formulation of the warrantees in the procurement phase**. Similarly, **clear guidelines should ideally be established on how liability in case of a multi-vendor system should be established and what type of measurements and logs should be kept in order to do so**. For any cases that fall outside these guidelines, **it is recommended to develop and commonly adopt conflict resolution models**.
- Technology qualification, testing & facilities – In a multi-vendor and multi-actor system, the performance of the whole system, and thus the benefit to a user of the system, relies on the performance and quality of individual parts of it. To ensure a minimum level of performance, all technology used in the system should be qualified to a minimum standard agreed between all users of the system. This applies to the level of QA/QC applied during fabrication, the tests done to prove technology meets the requirements, and the type of facilities these tests should be carried out in (capability to recreate suitable physical and functional stresses, and independence are aspects to consider). **It is recommended to agree on a common set of technical standards for use in the development of the HVDC grid, to carry out a gap analysis on the scope of currently existing standardisation and to initiate technical standardisation activities in missing disciplines**.

1.1.1 FURTHER RESEARCH, DEVELOPMENT & DEMONSTRATION

The PROMOTioN consortium is of the opinion that from a technical perspective there are no fundamental showstoppers towards the development of meshed multi-terminal offshore HVDC grids. However, several fields of further research have been identified that may lead to more cost-effective, environmentally friendly, optimally integrated and increased functionality development and usage of the meshed offshore HVDC grid.

1.1.1.1 INITIATE FULL-SCALE MULTI-VENDOR, MULTI-PURPOSE, MULTI-TERMINAL HVDC NETWORK PILOT

Individual technology elements have been demonstrated to have achieved sufficient maturity for deployment in real HVDC grids. The integration of these technology components into one functioning system has only been shown by demonstration, and even though there is no doubt that it is technically possible, many issues with regard to multi-vendor implementation have yet to be addressed. To achieve this and instil confidence in the technology, **the PROMOTioN consortium recommends the development of a full-scale pilot, which, procured on a commercial basis through competitive tendering, not only demonstrates the technology maturity but also realizes the potential benefit of multi-vendor, multi-purpose multi-terminal HVDC network solutions, compared to their point-point counterfactual case**. PROMOTioN has identified and analysed several potential sites in north-west Europe that could be suitable for such a pilot. The analysis has been further described under the short-term projects section in Chapter 3.

1.1.1.2 EXPLORE THE NEED FOR FLEXIBILITY IN THE SYSTEM

The availability of flexibility options, in particular energy storage, at the onshore hosting points has a strong effect on the ability to realize offshore grid integration synergies. Increasing onshore hosting capacity significantly reduces the total cable length required for all concepts but is more beneficial for the NAT, EUR and HUB concepts. Additionally, in the benefit analysis of 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 due to onshore grid congestion or low demand. For these reasons it 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. **It is recommended to carry out an integrated offshore grid planning study, taking into account onshore AC grid constraints and options for flexibility.**

1.1.1.3 PERFORM INTEGRATED AC/DC SYSTEM STUDIES

The PROMOTioN physical scope has been conveniently limited to the onshore landing points of the offshore HVDC grid. It is however clear that the integration of large amounts of power delivered by the offshore HVDC grid into the existing onshore AC grid is a formidable challenge, and will have strong influence on the topology and functionality of the offshore HVDC grid. The ability of AC grids to host the HVDC connections points is limited due to capacity constraints, constraints due to changing technology, constraints due to changing behaviour and roles of grid users. System integration, in the widest sense of the word, considering the path from generator to consumer, is they key aspect. Whereas EU projects such as PROMOTioN and BestPaths have delivered technical and regulatory solutions for HVDC grids, and MIGRATE and GARPUR have focused on the evolution of AC grids, **it is highly recommended to initiate research and development considering the system integration of large-scale pan-European HVDC grids into the incumbent but rapidly changing AC grids**.

New **tools and modelling approaches** for representation of large HVDC systems and integrated system studies need to be developed. Currently, time domain grid integration studies of HVDC systems can take many hours to run per scenario, many scenarios need to be considered, and the results are evaluated by hand to determine if operation is for example grid code compliant. The sheer amount of processing time required makes it almost impossible to do so for a large integrated grid. New simulation approaches, automated evaluation, and new modelling techniques should be developed in order to study the **interaction** between AC and DC systems for different time frames and contingencies and thereby facilitate the integration of large HVDC grids into existing AC grids.

Successful operation of integrated HVDC and AC grids will require the development of **control and communication concepts** for integrated system operation. The real-time dispatch of variable renewable energy sources, storage and ancillary services should be integrated vertically through the different layers of European and national transmission as well as distribution, taking into account the ability of both consumers, variable energy sources and storage options in different levels of the power system to contribute to system stability. In addition, the coordination should be integrated horizontally between different countries and users of the power system, fully making use of the possibilities offered by automated digital control systems. Next to developing the technical solutions, research should be initiated regarding the governance and regulation of the integrated power system operation i.e. which party owns and operates the different power system operation aspects and what market models can offer appropriate risk-reward balance.

1.1.1.4 CARRY OUT RESEARCH INTO OFFSHORE WIND FARM ADVANCED CAPABILITIES

Offshore wind farms are envisaged to take up a significant share of the future generation mix and thereby replace conventional generation. PROMOTioN has shown that the ancillary services of conventional power plants such as reactive power support, power oscillation damping, frequency support and black start operation can in principle also be delivered by HVDC connected offshore wind farms. To realize these abilities will require modifications to turbine and converter control systems, auxiliary power supply arrangements and the system control and communication systems. **It is recommended to carry out further research, development and demonstration work on how to realize, qualify and further enhance offshore wind farm ancillary service technologies, and crucially, how to integrate them into the offshore HVDC grid and the wider AC/DC power system.**

1.1.1.5 ANALYSE THE HVDC HUB TOPOLOGY

PROMOTioN did not study different types of HVDC hub implementations and their pros and cons in great detail. When implementing hubs, different designs (e.g. different numbers of and type of busbars, and the number and connection of HVDC circuit breakers) can be adopted that have different impacts on the level of redundancy and selectivity of fault clearing. **It is recommended to carry out a full lifecycle costs and benefits analysis to determine the applicability of AC vs DC hubs in different scenarios**. Furthermore, **it is recommended to establish technical design considerations for DC hubs**, especially in the light of power system redundancy requirements and protection.

1.1.1.6 CONTINUE DC SWITCHGEAR DEVELOPMENT

Further development of HVDC switchgear is foreseen to be necessary in order to improve reliability, improve operation, reduce environmental impact and reduce costs.

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, demonstrating their long-term viability whilst offering solutions for the often vendor-specific operation and maintenance aspects of these different alternative gases**. In addition, several key components which are necessary for offshore HVDC grid development such as high-speed switches and pre-insertion resistors do not currently exist as gas insulated components. Similarly, test requirements and procedures for these components need to be developed and standardised. 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 a commercial application at 320 kV and a full scale pilot at 525 kV.

With regard to HVDC circuit breakers, several prototypes have been developed and PROMOTioN has demonstrated that the technology is in principle ready for application. However, due to the use air insulated components in many HVDC circuit breaker technologies, and due to the sheer number of components required, they are typically rather large devices and require a substantial footprint. Offshore, this footprint comes at a significant cost which hampers the uptake of these devices. **It is recommended to carry out further research on HVDC circuit breaker topologies with the aim of reducing their cost and footprint.** Potential avenues are the use of gas insulated components, novel types of valves, improving speed of operation, etc.

1.1.1.7 FOCUS EFFORT ON INTEROPERABILITY OF CONTROLS AND PROTECTION

Interoperability between control and protection systems, particularly when supplied by different vendors, is seen as a significant hurdle towards HVDC grid development. As discussed in section 4.5.2, this concerns predominantly the communication interfaces, but also mechanical and electrical interfaces and dynamic performance. **It is recommended to focus significant effort onto standardisation activities that address these issues and carry out further research on control & protection strategies that are less prone to issues due to different vendor implementations**. Examples of such approaches are the open-source implementation (and licencing) of control & protection layers of converters that have an impact on the system behaviour (i.e. upper level controls).

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

A major obstacle to realizing synergies in transmission needs using HVDC grids is the absence, low technology maturity and potential cost of DC-DC transformers. Currently, a DC-DC conversion would need to be done using a back-back DC-AC-DC conversion, similar to frequency converters between different synchronous AC zones. This makes it impossible or costly to connect HVDC grids with different voltage levels and optimize those for a class of power ratings and transmission distances. Furthermore, DC-DC conversion may be a necessity in more complex meshed HVDC grids to control power flows.

Research, development and demonstration into cost-effective options for HVDC to HVDC conversion is thus essential. 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.

5. Stakeholder actions for the development of a Meshed Offshore Grid
6. Conclusions
7. Bibliography

   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:

1. 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.

2. An overview of the current offshore wind deployment plans, including upcoming multi-terminal and meshed or hybrid asset projects. This is followed by details of the grid topology to 2050 under each of the four grid concepts.
3. Details of the technical developments and decisions still required to deliver the 2050 topologies, and recommendations on how to deliver these.
4. Recommendations and rationale for the legal, regulatory and financial frameworks for a multi-terminal and meshed grid and who should deliver these recommendations.
5. A discussion on different market models for a multi-terminal and 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.

1 INTRODUCTION

At the end of 2019, 22.1 GW of offshore wind capacity was installed across Europe with 90% of this capacity concentrated in the Northern Seas [1] (North Sea, Irish Sea, English Channel, Skagerrak Strait and Kattegat Bay). This is a 10-fold increase over the last decade and the installed capacity continues to grow, with a clear pipeline of projects stretching into the 2020s across the North Seas countries [2]. Currently, most of the existing wind generation (~16 GW) is transmitted to shore using point-to-point High Voltage Alternating Current (HVAC) connections. As distance to shore increases, the need to use High Voltage Direct Current (HVDC) to minimise the losses from transmitting electricity increases. Additionally, as the cost of transmission increases due to longer distances, it is increasingly important to maximise the use of offshore transmission assets. Therefore, a meshed or multi-terminal offshore grid is proposed as a solution, where multiple windfarms are aggregated and connected to offshore transmission assets which also operate as interconnectors between countries. This evolution from point-to-point towards multi-terminal connections and meshed grids is an attractive option which could satisfy EU goals to efficiently integrate renewable energy and increase interconnection, while maximising social benefit.

The PROMOTioN programme (Progress on Meshed HVDC Offshore Transmission Networks) has advanced the HVDC technology required to design, build, operate and protect multi-terminal and meshed HVDC transmission grids; namely control systems, DC circuit breakers, HVDC protection systems and Gas Insulated Switchgear (GIS)[10]. 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 3 shows the impact of this research and testing on the Technology Readiness Level (TRL) of the technologies examined within PROMOTioN [5]. Figure 4 summarises the work package (WP) structure.

Alongside the technical work packages, work package 7 developed legal & regulatory, economic, financial, governmental and market solutions[11] to remove non-technical barriers and accelerate the development of an HVDC multi-terminal and Meshed Offshore Grid (MOG) in the North Seas.

[10] Diode Rectifier Units, a type of converter, were initially studied in a separate Work Package 8 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.

[11] Also developed in Work Package 12.

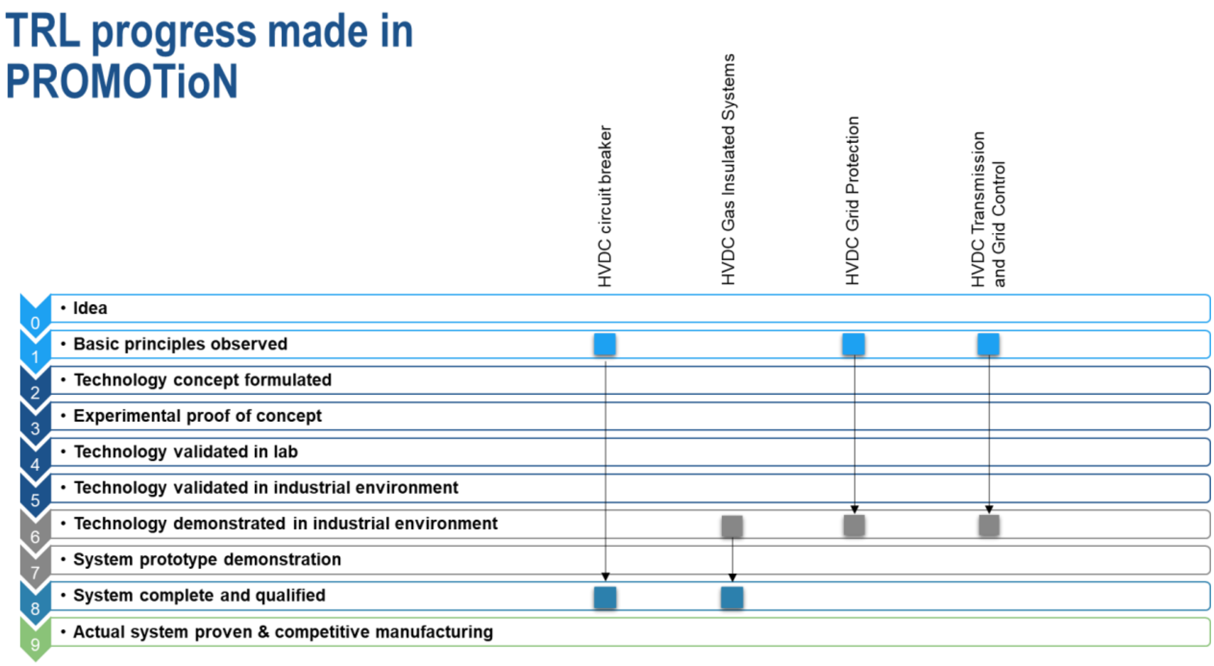


Figure 3 Technologies and their Technology Readiness Level. Those with arrows to open boxes indicate progress made within PROMOTioN (TRL before and after).

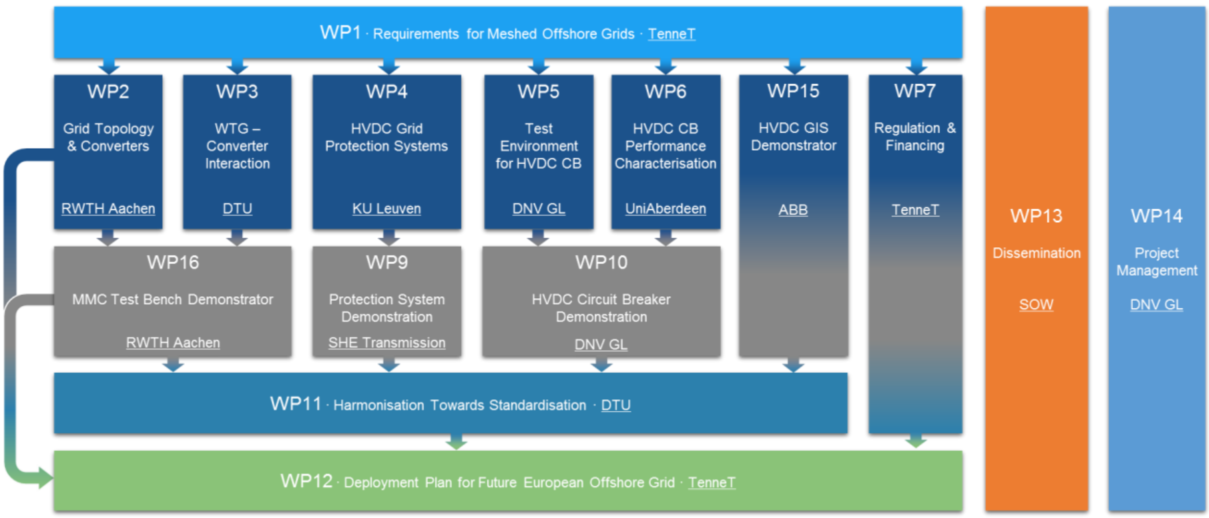


Figure 4 - PROMOTioN Project Structure as of November 2018.

This deliverable is part of WP12, which has sought to consolidate findings from across the PROMOTioN project in order to develop a deployment plan of what tasks need to be completed and in which order to construct a Meshed Offshore Grid.

This document, Deliverable 12.4 - Final Deployment Plan, is a roadmap to the future, describing steps required to develop an offshore grid to evacuate offshore wind energy to shore and to provide interconnection between countries bounding the North Seas. It uses the conclusions of prior work in all PROMOTioN work packages, and to a limited extent other research programmes, to identify the milestones required to develop a MOG.

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 fourth of five reports from this work package and finalises the deployment plan for a Meshed Offshore Grid. The preceding deliverables, Deliverables 12.1, 12.2 and 12.3 are described in more detail below, along with a summary of the remaining WP12 deliverable – Deliverable 12.5.

1.1.1 DELIVERABLE 12.1 – PRELIMINARY ANALYSIS OF KEY TECHNICAL, FINANCIAL, ECONOMIC, LEGAL, REGULATORY AND MARKET BARRIERS AND RELATED PORTFOLIO OF SOLUTIONS

Deliverable 12.1 was a literature review of the work completed prior to and interim findings within the PROMOTioN project at the time of writing [21 December 2017]. This document defined the scope for much of the research done in PROMOTioN. 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. Deliverable 12.1 also includes a literature review of other research in this area.

1.1.2 DELIVERABLE 12.2 – OPTIMAL SCENARIO FOR THE DEVELOPMENT OF A FUTURE OFFSHORE GRID

Deliverable 12.2 details the outputs of the CBA carried out on four potential and different offshore grid designs (concepts) under alternative offshore wind deployment scenarios. The outcomes of this CBA feed into this deployment plan along with recommendations from other work packages. The concepts highlight how wind generation should be planned, and which topology will give social benefit. These concepts do not provide a hard and fast solution.

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 should be located based on GIS studies and current exclusion zones, and thus forecasts offshore wind generation. It also describes how the topologies are derived and specifies a grid architecture for each option, at 5 year intervals up to 2050. These concept-scenario combinations (topologies) show a range of possible options for grid development, but they are not mutually exclusive; in reality the grid may draw on all four concepts (see Section 1.2.2 and Appendix I for further details). The document also explains the underlying assumptions, design choices and reasoning behind these topologies. Again, these choices represent current best knowledge, a combination of available and planned future technology. PROMOTioN anticipates that a global transmission industry may develop differently from our predictions. 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 and sensitivities found the recommendations in this document.

1.1.3 DELIVERABLE 12.3 - THE PRELIMINARY DEPLOYMENT PLAN

Deliverable 12.3 presented a draft deployment plan on what is required and when in order to facilitate the construction of a multi-terminal offshore network with a goal to support 2050 climate goals. 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 concludes the work that has been done in the WP12 and presents the final recommendations for the deployment plan of the HVDC MOG. The recommendations will incorporate feedback on Deliverable 12.3 drawn from a broad stakeholder consultation as well as final conclusions from other work packages as these come to conclusion.

1.1.5 DELIVERABLE 12.5 - SHORT TERM PROJECTS REPORT

This report is a summary of studies done by PROMOTioN on behalf of partners for real potential projects. Scope varies per project and is dependent on the partner needs. Because of the sensitivity of this information the document is available to the EC and partners only.

1.2 APPROACH OF WORK PACKAGE 12

This section introduces the offshore wind deployment scenarios and grid concepts used to build the grid topologies.

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 examined three different offshore wind deployment scenarios for the North Seas by 2050 - Low (90 GW), Medium (150 GW) and High (205 GW). Each scenario is developed in five year time steps.

Table 5 depicts an overview of the three offshore wind 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.

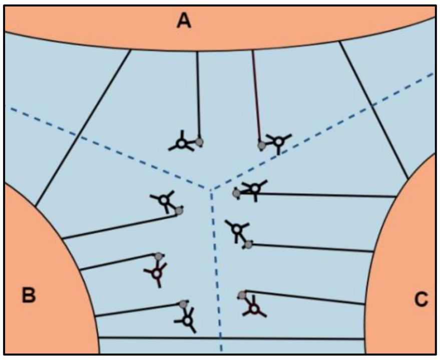
Table 5 - Overview of three deployment scenarios used in PROMOTioN (values in GW).

	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

It is important to state here that both the planned generation capacity roll out and wind locations are kept the same in all scenarios, in order to have objective comparison of the concepts. However, it is considered that this may be unreasonable. In reality, it can give benefit to adjust OWF build-out based on planning around a specific concept.

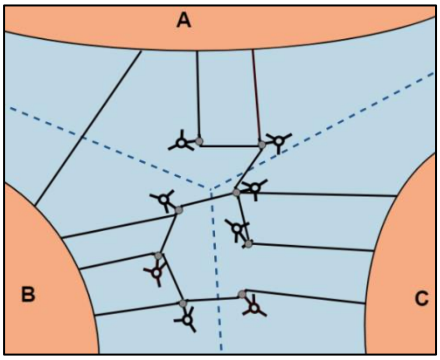
1.2.2 GRID DEVELOPMENT CONCEPTS

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 5 below provides a simplified representation of each concept. In each of these representations, the same windfarms are connected according to the philosophy of each concept. These representations are deliberately technology-agnostic and merely display the high-level differences between each of the concepts. PROMOTioN would like to stress that in reality any grid that is constructed will more likely be a combination of these options rather than possess elements of merely one single concept. These Grid Development Concepts are described in more detail in Appendix I and in Deliverable 12.2.



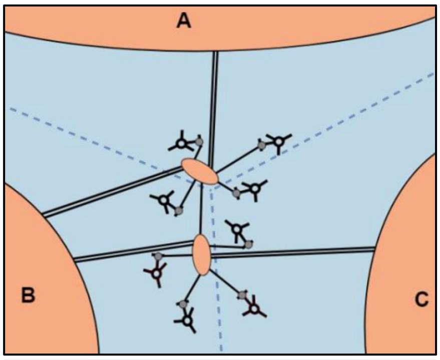
Business as usual (BAU)

The offshore wind farms (OWFs) are connected to the grid point-to-point. This may be in separate point-to-point connections, but some OWFs might also be bundled to reach a critical size of 2 GW in order for power to be evacuated along standardised 525 kV 2 GW bipole cables, which have not yet been deployed. This scenario is not therefore a continuation of current business-as-usual practices, but rather a continuation of current trends. Power exchange between countries is facilitated by separate point-to-point interconnection.



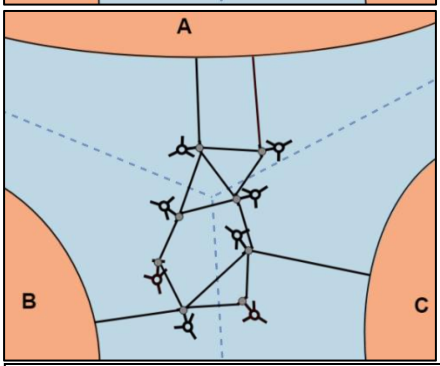
National Distributed Hubs (NAT)

This concept is based on a national approach to offshore grid construction. The scope of the national offshore grid is first and foremost to evacuate the generated wind power from each country's EEZ to its onshore grid. The national offshore grids may also be strategically connected to each other. During low wind conditions these connections provide trading capacity between the national onshore grids. Dedicated interconnectors may exist in parallel to these connections for energy trade between countries.



European Centralised Hubs (HUB)

This concept proposes the creation of several AC "central hubs" to which several OWFs are connected. Power is evacuated to shore via strong DC connections connecting different countries. These hubs also provide trading capacity between countries during periods of low wind generation, which enables trading and/or dispatching to different connected regions.



European Distributed Hubs (EUR)

This concept includes small, platform-sized hubs which are spread out across the North Seas and connected to each other via DC connections and to nearest landing points independent of EEZ. These hub connections provide interconnection between countries during periods of low wind generation.

Figure 5 - Illustration of the different concepts.

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 is an assessment of the costs and benefits of an investment decision in order to assess the welfare change attributable to it [6] 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 methodology describes how the different concepts can be scored on a range of 'Key Performance Indicators' (KPIs) with which the costs and benefits can be assessed. An overview of the costs and benefits is presented below in Table 6 for the quantitative KPIs and Table 7 for the qualitative KPIs. This is an aggregation of the costs and benefits over the entire analysed period. For more insight into the analysis that led to these results, refer to Deliverable 12.2.

In terms of Capital Expenditure (CAPEX) and Operating Expenditure (OPEX), the HUB concept provides the best alternative to the BAU concept due to its usage of artificial islands in lieu of HVDC platforms. The cost analysis also showed that this is true for the High and Central wind scenario, but not for the Low wind scenario, where the number of HVDC platforms displaced by the artificial islands is too low to create a cost advantage[12]. The NAT and EUR concepts have slightly higher CAPEX and OPEX costs than BAU. This is due to the fact that the reduction in cable length is only minor and does not fully compensate the additional protection system costs increase due to the meshing of the grid. While protection costs are between 2-9% of infrastructure costs, the space costs on platforms also need to be included.

All concepts show some benefits compared to BAU, although some of the concepts have worse scores than the BAU scenario on specific KPIs. For example, the HUB concept scores worse than BAU in all three wind scenarios on KPI B2: Renewable Energy Sources (RES) integration, which evaluates the curtailment of renewables in the system. The onshore landing of power is in the wrong country/locations and energy will need to be transported onshore to the place of consumption. Raising the capacity on strategic interconnectors could remove this impact, such as between Netherlands, Germany, Denmark and Norway.

As one of the main conclusions of the benefit analysis is that the system lacks the ability to fully utilise its potential. The combination of B2: RES Integration curtailment and B6: Loss of Load Expectation (LOLE) indicates that generated energy may be consumed at other times. The installed capacity of hydro-pump storage is not sufficient in later periods as the only storage option available. Thus, more flexible options need consideration. With the current Research &Development status in mind, either battery storage or power-to-X may be considered. Raising the capacity on strategic interconnectors could also be a possibility, such as between Germany, Austria and Switzerland or Germany, Denmark and Norway albeit this may not remove all curtailment. Each concept demonstrates 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

[12] There may be specific situations where there is high wind, where an island solution would be cheaper. The "standardised" constraints and wind generation in the model used will not account for this.

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 has a lower environmental impact (S1), but higher social impacts (S2) than the HUB concept.

Therefore, any choice for a specific concept is not merely a judgment of costs and benefits. There is a trade-off of specific attributes an offshore grid may deliver. All options have relative advantages and disadvantages. PROMOTioN concludes that building using the HUB philosophy, may be the lowest cost option, but its benefits might not be as prominent as in the NAT or EUR concept. While PROMOTioN has developed the tool which may be used to objectively assess a preferred or specific grid concept, some stakeholders would attribute a different ranking to the benefit factors. PROMOTioN has chosen to follow ENTSO-E and does not translate these factors into comparative currency. Rather, the results of our analysis performed on the topologies are presented in the measured units and must be weighted by the respective National and Multinational agencies, in a process which inevitably may include a level of subjectivity. Also, it must be noted that these results should be interpreted within the constraints that PROMOTioN has used within the analyses, as is discussed in Appendix III. The different scenarios cannot easily be compared with each other as the underlying assumptions differ (only a comparison between concept topologies is valid). This is in most cases due to onshore differences and constraints. PROMOTioN has not considered modifying the ENTSO-E planned onshore development, and therefore a conclusion is that the proposals for an offshore grid are influenced by what happens onshore and vice versa. Long term onshore planning may require adjustments dependent on offshore grid plans.

Table 6 .- Overview of quantitative costs (C) and benefits (B) of the concepts. Note: B4 and B5 are not evaluated.

HIGH Wind Scenario						
Cost or benefit	**Cost or benefit**				**Unit**	**Notes**
	BAU	***NAT***	***HUB***	***EUR***		
C1: CAPEX	186,6	196,1	171,9	198,5	bn€	
C2: OPEX	54,5	57,1	55,2	57,8	bn€	
B1: Socio-economic welfare	-	10,4	7,6	0,1	bn€	
B2: Renewable Energy Sources (RES) integration	-	-83.300.000	235.900.000	-77.800.000	MWh	HUB landing points not optimised and would require onshore optimisation
B3: Variation in CO2-emissions	-	-41.000.000	-22.700.000	-6.300.000	t	
B6: Security of supply: Adequacy to meet demand (LOLE)	-	-720	-630	-720	MWh	
CENTRAL Wind Scenario						
Cost or benefit	**Cost or benefit**				**Unit**	**Notes**
	BAU	***NAT***	***HUB***	***EUR***		
C1: CAPEX	121,2	125,3	114,8	130,0	bn€	
C2: OPEX	36,3	38,3	35,9	39,7	bn€	
B1: Socio-economic welfare	-	0,7	-6,7	-1,0	bn€	
B2: Renewable Energy Sources (RES) integration	-	-600	139.800.000	-10.500.000	MWh	HUB landing points not optimised and would require onshore optimisation
B3: Variation in CO2-emissions	-	-10.000.000	61.600.000	17.100.000	t	
B6: Security of supply: Adequacy to meet demand (LOLE)	-	-	-	-	MWh	Same in all concepts
LOW Wind Scenario						

Cost or benefit	Cost or benefit				Unit	Notes
	BAU	NAT	HUB	EUR		
C1: CAPEX	74,8	74,1	74,1	75,1	bn€	
C2: OPEX	23,4	23,2	24,3	23,8	bn€	
B1: Socio-economic welfare	-	3,6	2,1	4,9	bn€	
B2: Renewable Energy Sources (RES) integration	-	4.700.000	41.200.000	5.700.000	MWh	HUB landing points not optimised and would require onshore optimisation
B3: Variation in CO2-emissions	-	-26.300.000	-15.900.000	-25.500.000	t	
B6: Security of supply: Adequacy to meet demand (LOLE)	-	-470	-480	-90	MWh	

[1] For each benefit (B), the BAU concept scores 0. All other concepts are scored relative to BAU. A negative value therefore indicates that the concept delivers benefits, a positive that the concept performs less well on the KPI compared to BAU, except for B1 where the reverse applies.
[2] Note that the Scenarios cannot be seen as a step improvement. Underlying assumptions are linked to the ENTSO-E scenarios: the High Scenario is linked to the Global Climate Action; the Central wind scenario corresponds to the Sustainable Transition Scenario, which retains fossil generation longer. The Low scenario is linked to the Distributed Generation model.

Table 7 - Overview of qualitative benefits of the concepts. Note: B4 and B5 are not evaluated. A low impact means little benefit, high impact means high benefit. These benefits are scored relative to having *no* offshore grid at all.

Cost or benefit	Cost or benefit				Unit	Notes
	BAU	NAT	HUB	EUR		
B7: Security of supply: System flexibility	Low	High	Medium	Medium	Increased flexibility in operation and levelling out uncertainties and variations in wind production.	
B8: Security of supply: System stability (security)	High	Medium	Low	Medium	Improved power oscillation damping, provision of synthetic inertia and black-start (assisting) capabilities and reactive power compensation and active voltage stability support	
B9: Security of supply: resilience	High	High	Low	Medium	Increase in resilience of power system	
S1: Environmental impacts	Vibration, wind effects and spreading of non-indigenous species	Vibration, wind effects and spreading of non-indigenous species	Noise, electro-magnetic fields, artificial substrate, sediment dynamics, wave actions and operational discharges	Vibration, wind effects and spreading of non-indigenous species	Effects of the concepts are described according to their impact on environmental factors.	
S2: Social impacts	High	Medium/low	Low	Medium/low	Space consumption, visual contamination and negative health effects	
S3: Other						
a) Possibility of gradual development	High	High	High	High		
b) Support for European industry	High	High	High	High		
c) Geopolitical advantages	High	High	High	High		
d) Increased European integration	High	High	High	High		

Green is positive, to red negative in impact

From the analyses made in Deliverable 12.2, recommendations have been drawn which are further be incorporated in Chapter 4 below. Note that these recommendations are in the light of PROMOTioN's analysis, in which several assumptions are made and some 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 parallel to the shore and basic point-to-point connections are dominant. Thus, meshing is more focused on national waters and cooperation between countries is low. As OWFs are installed further from shore, multi-terminal and meshed topologies are expected to emerge. A MOG will be formed by interconnecting OWFs and hubs with different onshore systems and other hubs. 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 are 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. 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 multi-terminal and 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):

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

Figure 6 summarises how each group of requirements are connected to the PROMOTioN WPs. More specified details regarding these requirements are described in Deliverable 1.1.

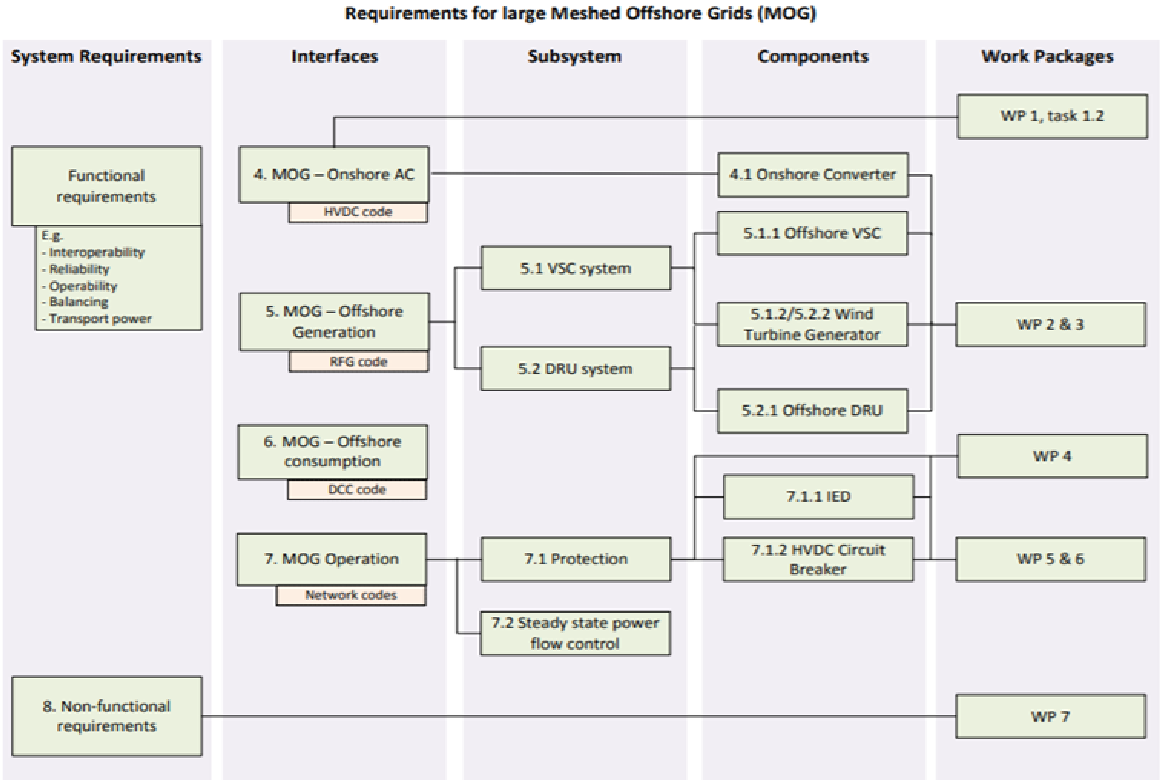


Figure 6 – Requirements for large Meshed Offshore Grids.

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 in Figure 7.

A detailed description of each category of advantages is presented below, based on research carried out in Deliverable 12.2. Note that these categories represent the KPIs in the CBA but are based on a theoretical analysis of these indicators.

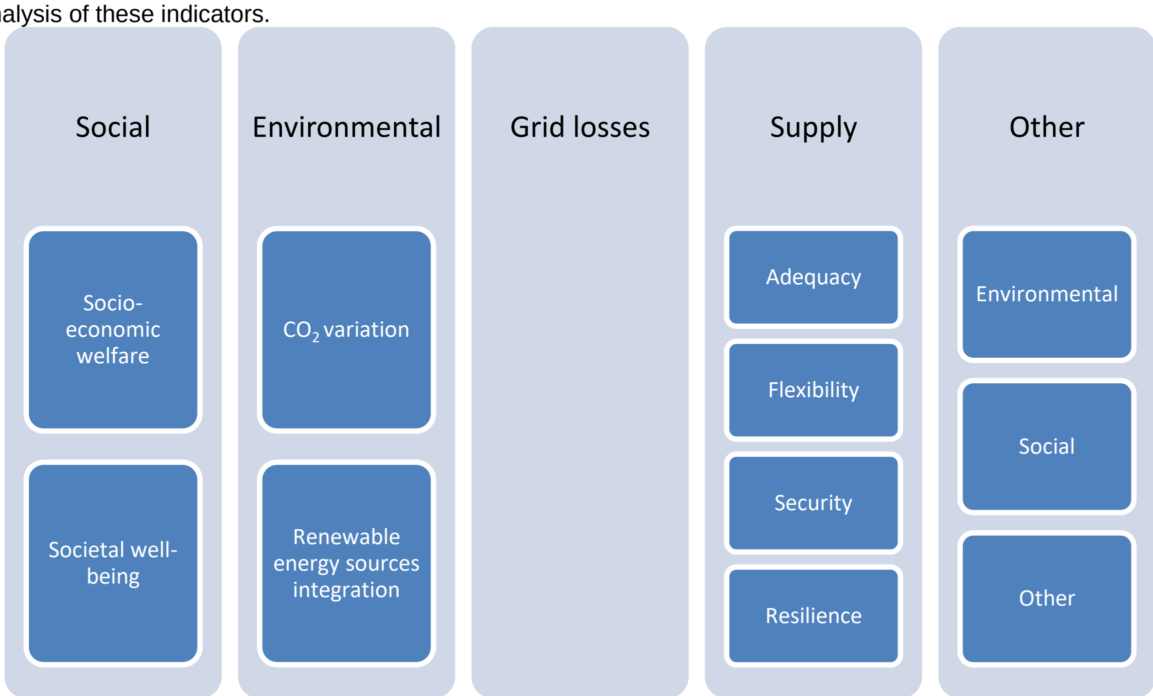


Figure 7 – Key advantages of MOG implementation.

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 is anticipated to 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 multi-terminal and meshed grid topology in which wind evacuation transmission assets are combined with interconnection use will be cheaper than a point-to-point solution with separate point-to-point interconnectors. This difference in costs is a consequence of fewer transmission assets required.[13]
- The MOG will result in an increase in the capacity credit of the offshore wind production. This is a consequence of the fact that the 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 has other benefits like the improvement of local air quality which 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 Carbon Dioxide (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 multi-terminal and 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.
- Within PROMOTioN the design of the EUR and HUB concepts are focused on evacuation to the nearest onshore landing points. This in fact leads to worse results for the HUB concept in RES integration than the

[13] Note: the BAU concept used in PROMOTioN is not a 'pure' point-to-point solution. Multiple OWFs are collected to a hub and the to shore. The Bipole configuration enables partial redundancy. However, the BAU concept has no planned interconnection. However, within our constraints, the savings from fewer cables in meshed solutions do not fully compensate for protection costs.

BAU concept. As an example, a high percentage of German wind generation is landed in Denmark and results in an increased congestion between Denmark and Germany. This disadvantage may be turned to an advantage if in future planning the offshore and onshore grids are both considered more integrally. The MOG may be used to alleviate congestion offshore.

- 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 multi-terminal and 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 multi-terminal and meshed grid can lead to improved utilisation of the potential different RES within the European system. A more 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 multi-terminal and 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 multi-terminal and 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 multi-terminal and 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. Nevertheless, the exact effects of the HVDC MOG on the onshore grid losses are still unclear until different operational strategies are modelled. Additionally, interconnecting and meshing grid elements could result in shorter pathways and more direct flows from the offshore generated wind energy to areas where it is required. For example, wind energy can be transported directly from the offshore grid to another country, rather than having to be transported to the onshore AC grid first, then traded through an interconnector with another country. This therefore decreases the conversion losses in the system.

Integration with the onshore HVDC planned connections may further benefit the system as offshore wind generation may be delivered directly to consumption centres. This has not been researched by PROMOTioN.

2.2.2.4 SECURITY OF 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 point-to-point wind evacuation connections. Since a meshed grid can create alternative paths for power evacuation, an outage of the primary connection to shore would not have any or would have a smaller effect compared to the point-to-point approach. However, due to the low failure rate of subsea cables, this benefit is only marginal.

SECURITY OF SUPPLY: FLEXIBILITY

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

- The multi-terminal and meshed grid would provide larger flexibility in operation than a point-to-point grid topology. This is due to the fact that a multi-terminal and 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. Additionally, as HVDC systems can behave like grid-forming components this would expand the options for system operators to

form their grid as preferred. 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 multi-terminal and meshed grid to level out a large portion of these deviations.
- This was most evident in the EUR and NAT concepts and in our case less so in the HUB solution. However, PROMOTioN concepts did not consider fully interaction and optimisation of the onshore grid – which disadvantaged the EUR and HUB solutions. In reality the two cannot be built in isolation, and there are simple 'fixes' to the onshore grid that would allow similar benefits for the HUB concept.
- The benefits of flexibility were less obvious than anticipated in the EUR concept due to high cable utilisation.

SECURITY OF SUPPLY: SECURITY

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 simple point-to-point topology, a MOG can increase the reliability of this service because of an increased capacity credit of offshore wind. Hence, a multi-terminal and meshed grid can reliably offer this service, whereas a point-to-point developed offshore wind grid would be less capable of doing so. However, the specific constraints for BAU in PROMOTioN made this concept rather robust. The bipole configuration provides for solid security of supply. The focus on evacuation however, actually reduced this in multi-terminal and meshed concepts as more efficient utilisation of cables resulted in less excess capacity. Construction of excess capacity to provide increased benefit of security of supply did not pass the cost benefit optimisation. Therefore, for our specific concepts, this remains unproven.
- 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. Although a point-to-point solution is also capable of delivering this support, the HVDC converters are not in direct communication in such a solution which makes it more difficult to have these deliver support simultaneously.

SECURITY OF SUPPLY: RESILIENCE

The MOG would involve a high degree of decentralization 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 parts of the grid can be isolated while other parts of the grid keep functioning.

According to Cigré WG C4.47, power system resilience can be defined as “the ability to limit the extent, severity, and duration of system degradation following an extreme event”[14]. The evaluation of the resilience of a power system requires thus (i) an assessment of the possible threats or hazards (natural disasters and/or terrorist threats) that could lead to extreme events (including their likelihood), (ii) an assessment of the survivability of the system following an extreme event (i.e. limitation of the extent and severity of system degradation), and (iii) an assessment of the reparability and the restorability of the system (i.e. limitation of the duration of system degradation).

For offshore grids in the North Seas, natural hazards would be mainly earthquakes and heavy storms[15] (potentially causing rogue waves). While the area is from a global perspective not known for earthquakes, smaller ones occurred during the last decades and should not be excluded in a detailed consideration. The same applies for rogue waves. While physical terrorist threats could occur in the future, the probability of cyber-attacks to access the control systems must also be considered and at present may represent a higher risk, but this may also be the easiest to recover from or mitigate.

If the threats are the same for all concepts, the survivability of the offshore grid following the occurrence of an extreme event could vary strongly from one concept to another. Indeed, in the BAU concept, the failure of one connection, be it because of the converter or cable, leads only to the loss of a maximum of 2 GW installed generation capacity, whereas the loss of a busbar in the NAT or EUR concepts could have a potentially bigger impact. These two multi-terminal and meshed concepts have the positive characteristics that alternative paths to shore could be available, depending on the impacted topology. The loss of a complete island in the HUB concept means the loss of several Gigawatts of installed generation capacity, as most of the surrounding offshore wind farms are connected through that hub. Alternative paths to shore are usually not available in the HUB concept. This short qualitative assessment leads thus to the conclusion that the natural survivability of the BAU concept is probably the best and that the natural survivability of the HUB concept is probably the worst, with the NAT and EUR concepts in the middle. However, we must also consider that freak weather conditions may impact multiple hubs, which would result in extended restorability time. It must also be emphasized that the survivability can be improved through dedicated control schemes.

Finally, regarding the repair and the restoration process (which must thus consider the time needed to repair the damaged components), a notable difference between the HUB concept and the other ones must be emphasized. The HUB concept has the advantage of having several complex components on an island, which could decrease the time needed to bring repair crew and spare parts at the relevant locations and thus the repair times. The situation with the rest of the components is similar to the BAU, NAT and EUR concept. Experience with large repairs of offshore components are rare, but available data suggests significantly higher values for the *mean time to repair* (MTTR) than it would take onshore [7] [8][16]. The reasons are the strong weather dependency (finding a suitable weather window), combined with limited availability of transportation and unique working ships and experienced personnel for this specialist work [9]. Summarised, the developed offshore systems are rated worse than the available onshore systems on this last assessment.

Overall, PROMOTioN has not made any quantitative risk analysis or formal assessment of these relative risks. This may be a subject of a study in itself. We would therefore recommend further studies or formal assessments

[14] E. Ciapessoni, D. Cirio, A. Pitto, M. Panteli, M. Van Harte, C. Mak, "Defining power system resilience”, Electra, October 2019
[15] Currently, weather systems are becoming increasingly volatile and the concept of extreme storms does not appear to be impossible, see **https://www.thetimes.co.uk/article/ninian-south-oil-workers-evacuated-as-storm-caroline-looms-0bgkztkk3**
[16] For instance, shipping and installation of the components is likely to take longer when compared to onshore-only repair times.

of risk on the specific proposed topologies. As such, we have made a subjective assessment of the different concepts. We consider the BAU concept as most resilient in the case of a disaster and the HUB concept as the least if the hub infrastructure is attacked or subject to natural disaster. Meshed and multi-terminal grids are in the middle. Cable and grid damage favours multi-terminal and meshed and hub grids. Lastly in the case of an attack on control systems, these are likely to endure shorter times but may have a broader system impact. The control of multi-terminal and meshed grids is more complex, and may have a harder impact. However, all systems may suffer in such a situation.

2.2.2.5 ENVIRONMENTAL

The MOG will not substantially reduce environmental impact based on the assumptions used in PROMOTioN. The evaluation of BAU versus NAT and EUR concepts is similar as these have a similar number of platforms, based on assumptions of cable size and infeed. The HUB concept, based on a single HUB replacing on average 11 platforms may impact the environment in a number of aspects, mainly positively. Also, the potential to reduce the number of cables may be significant. While it is anticipated that the amount of cables laid will be largely similar, there is an opportunity to bundle. As bundled cables may have a larger electromagnetic field effect (not yet known or fully evaluated) this may have a longer term impact. However, if transmission asset builders are able to bundle and trench corridors early on, this will result in lower impact during construction.

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.

BAU: Large number of platforms (vibrations, but potential benefits of reef forming, etc.) and cables (warming, trenching)

NAT: Fewer platforms and cables

EUR: Similar or same platforms as NAT; but fewer cables

HUB: Fewer offshore platforms, islands (high seabed damage during construction, but may form breeding ground for birds, long term impact unknown), fewer or clustered cables,

CONCLUSIONS

The original hypotheses of PROMOTioN are not all proven by PROMOTioN analysis. Indeed, it is clear that not all anticipated benefits are realised within PROMOTioN constraints. What has become clear is that given current onshore constraints, the design of the grid elements excludes large scale connections that may in later years be possible. The focus on evacuation, perhaps undervalues the importance and potential benefits if we also are able to solve onshore issues. The optimiser focused on evacuation of offshore generation and then on interconnection, but does not convert the additional benefits of meshing into financial benefit. Landing electricity at the nearest landing point to the hub is not always leading to the maximum social benefit. The onshore and offshore grids cannot be considered in isolation, and some work needs to be done to match the needs of a total solution.

3 2020 – 2030: CURRENT DEVELOPMENT PLANS

Today, the majority of developed OWFs are near shore and point-to-point connected with HVAC connections. However, the losses associated with moving electricity greater distances are recognised and current projects are increasingly looking to use or apply HVDC technology to reduce these losses.

The CBA indicates that meshing and multi-terminal connections are developed early in the 2020-2050 period, once Business as Usual constraints are released. There is some evidence of high potential investment savings if larger hubs are built, especially in areas of high wind. The short term challenge is to foster an environment that promotes a hub approach. In order to trigger these the control and protection technology does still require industrial testing.

Short-term HVDC projects present the opportunity to demonstrate and (industrially) test 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. These projects also present an opportunity to evaluate and implement legal, regulatory and market frameworks which will facilitate the deployment of multi-terminal and meshed HVDC offshore grids. Early development of a consistent legal, regulatory and market approach to multi-terminal and meshed grids will be beneficial for the incremental development of the grid, by avoiding bespoke approaches for individual projects which are then difficult to bring together.

Short Term Projects is the name of a separate subtask within Work Package 12 (WP12) which aimed at identifying and analysing potential "real" projects that could be modified to demonstrate and industrially test HVDC technologies. The primary goal is to gradually increase complexity from the business-as-usual solutions (primarily point-to-point links) to multi-terminal HVDC systems.

This Short Term Projects subtask focused on three projects, each with a different potential to utilize multi-vendor technology, HVDC protection and new regulatory & market schemes. These projects, listed in order of increasing complexity, are:

1. SouthWest Link – Hansa Power Bridge DC Connection. DC-side connection of two HVDC corridors with the goal of reducing grid losses, increasing availability and interconnection level between Sweden and Germany.
2. WindConnector DC protection. Installing DCCB on an offshore platform to protect Dutch onshore grid from the faults in the hybrid cable between Dutch and British offshore windfarms.
3. Bornholm island CleanStream energy hub. Offshore hub combining functionality of offshore energy evacuation and interconnection between Denmark, Poland and potentially Germany.

A full overview of research and findings for these potential pilots can be found in a Short-Term Projects supplement to this deliverable [10].

3.1 PLANNED HVDC PROJECTS

The ENTSO-E TYNDP for 2018 identifies planned offshore transmission assets out to 2040 (Figure 8). 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 shore, despite the fact that offshore energy generation capacity in the region is anticipated to be 125 GW in 2040 according to its Global Climate Action Scenario [11].

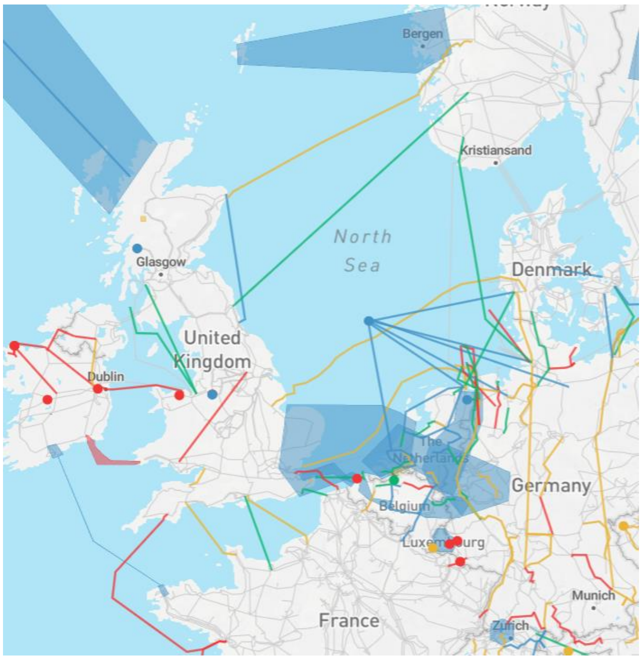


Figure 8 - ENTSO-E Map of proposed projects in the North Seas. Source: ENTSO-E TYNDP 2018.

3.2 ATTITUDES TO SHORT TERM MULTI-TERMINAL HVDC GRID PROJECTS

Stakeholder engagement and partner consultations performed by PROMOTioN consortium 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, as no urgent need was identified by developers. The reasons quoted to PROMOTioN partners for avoiding multi-terminal HVDC projects are:

1. **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.
2. **Too risky**. TSO management and Regulators are risk averse; TSOs are unwilling and unsure how to justify the use of HVDC CBs and protection in an untested environment to the regulator.
3. **Too expensive**. The capital costs are anticipated to be too high for an individual project. In particular, the space that is required for an HVDC, multi-terminal project is large resulting in materially larger offshore platforms.
4. **The legal and regulatory environment is not yet ready for multi-purpose projects**. Temporary workarounds can facilitate a unique solution, but this is not always a favoured solution. Most of the multi-purpose projects require significant alterations in the existing regulations and this is perceived to be a long process.
5. **Too complex to manage stakeholder views**. Most of the hybrid projects involve two or more countries, and 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 are involved, interoperability.

6 **Planning processes are not designed for complex projects.** The current planning process is designed for individual and uncoordinated projects that are delivered as standalone projects. A more strategic approach is not easy to deliver due to its limitations in connections to the onshore grid, the non-technical barriers and the short planning horizon for projects.

7 **Lack of technical expertise**. There is also insufficient experience within the TSOs to consider HVDC multi-terminal connections. All studies that have been performed in Europe so far are largely academic projects delivered in a lab environment, i.e. they have not resulted in commercial or pilot projects. The only existing experience in a relevant environment is on land in China.

8 **Procurement and interoperability risks**. There is little to no experience with building multi-vendor HVDC projects. It is expected that, in such systems, performance guarantees from the manufacturers would be withdrawn as these conflict with conventional turn-key project approach. Equipment suppliers ensure operational stability based on the extensive in-house testing of various equipment and systems. In a multi-vendor environment, full-system testing is currently impossible as it would mean sharing technical details and specifications with competitors in a highly non-standardised industry.

3.3 MOTIVATION

PROMOTioN has evaluated the technical feasibility, costs and benefits, risks and the legal and regulatory barriers of real existing or planned projects which may be suitable for testing new HVDC equipment. It is believed that deployment of multi-terminal, multi-vendor grids has to be achieved in a step-wise manner, gradually increasing complexity of the projects and keeping the risks identified above tolerable.

The diagram in Figure 9 shows, from left to right, how projects can evolve from the current state, and which planned projects fulfil the criteria.

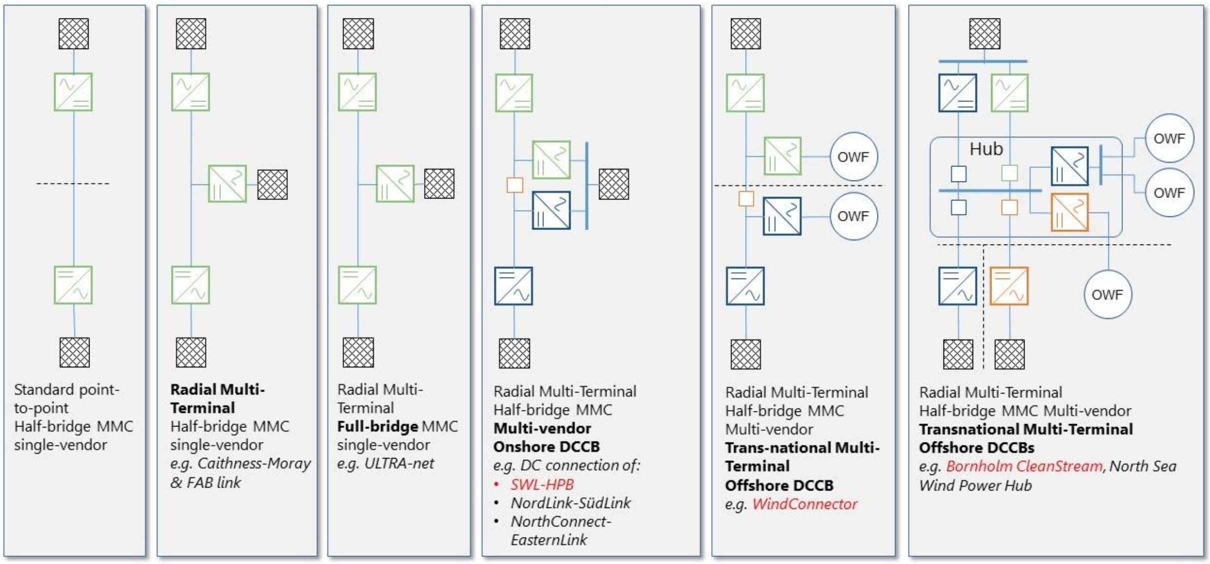


Figure 9 - Increasing complexity of Multi-terminal Multi-Vendor HVDC

This Short Term Projects subtask focused on four projects, each with a different potential to utilize multi-vendor technology, HVDC protection, and new regulatory & market schemes. These projects, in the order of increasing complexity are:

1. SouthWest Link – Hansa Power Bridge DC Connection. DC-side connection of two HVDC corridors with the goal of reducing grid losses, increasing availability and interconnection level between Sweden and Germany.

2. WindConnector DC protection. Installing DCCB on an offshore platform to protect Dutch onshore grid from the faults in the hybrid cable between Dutch and British offshore windfarms.
3. Bornholm island CleanStream energy hub. Offshore hub combining functionality of offshore energy evacuation and interconnection between Denmark, Poland and potentially Germany.
4. NorthConnect & EasternLink, and NordLink &SuedLink connections were reviewed, but PROMOTioN has not performed analysis of these proposals.

These projects' geographic location is given on the map in Figure 10, where some other opportunities are also identified.

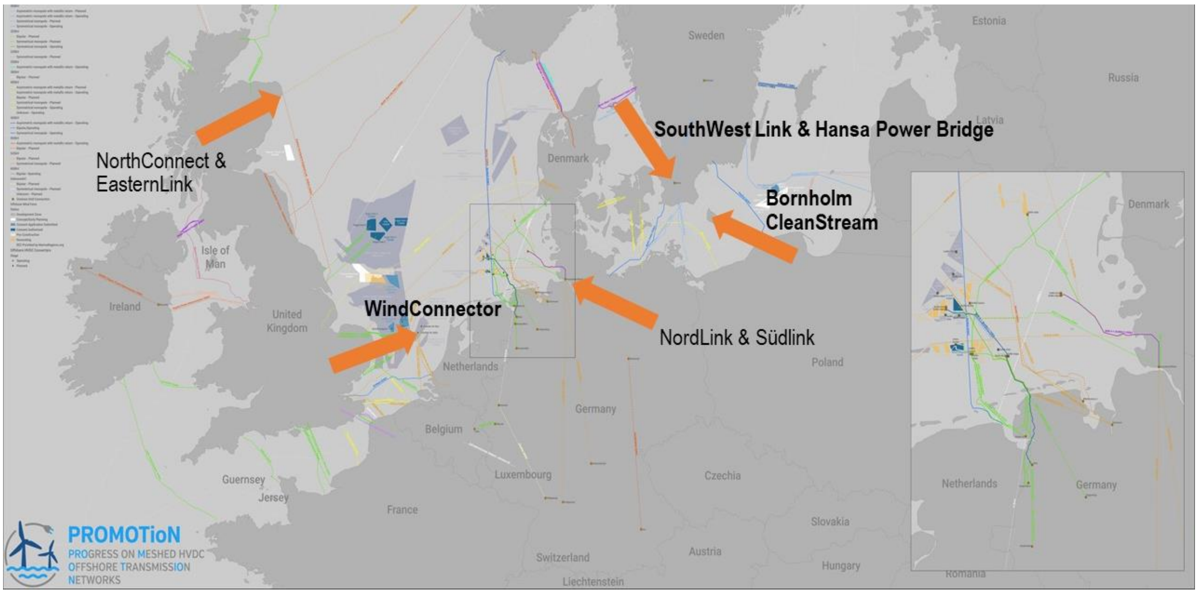


Figure 10 - Geographic location of identified short-term opportunities for HVDC technology deployment

3.4 SCOPE OF STUDIES AND SUMMARY

Delivering each of the above-mentioned projects entails its own barriers and complexities related to technical, regulatory, economic or financial dimensions. PROMOTioN has addressed known issues based on the availability of information and support from the project promoters. This has resulted in a different scope and level of detail in the analysis for each of the short-term project as shown in Figure 11.

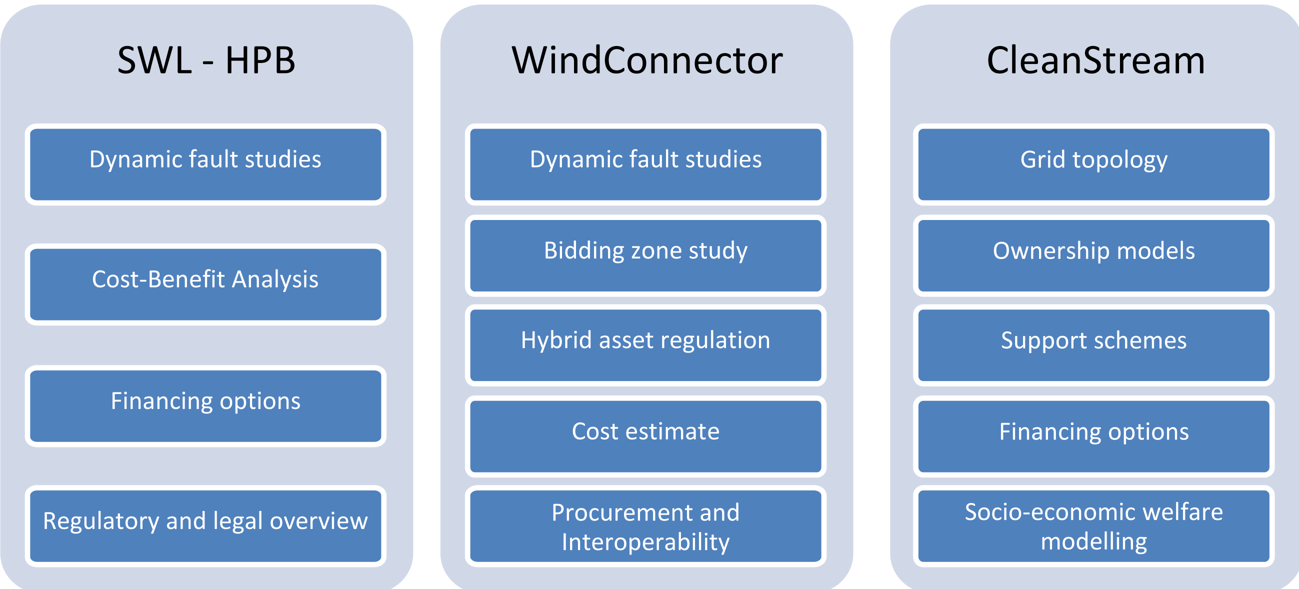


Figure 11 - Scope of performed studies under Short-term Projects subtask of WP12

3.4.1 SOUTHWEST LINK – HANSA POWER BRIDGE (SWL-HPB) DC CONNECTION

For this project PROMOTioN has analysed in detail grid topologies, technical requirements and implications, conducted Cost-Benefit Analysis (CBA) of various configurations and DCCB technologies, and given recommendations for some of the regulatory, legal and financing (market and commercial) aspects. This proposal, if implemented, could be realized by 2028, and compared to the other two projects covered in this chapter, requires limited alterations to the original scope. Furthermore, the DC link would be located onshore which further reduces the complexity and allows some of the risks inherent to offshore environment to be avoided. The focus is on DCCB and multi-vendor DC connection which allows a reduction in losses from energy conversion and an increase in availability of the transport corridor between Sweden and Germany.

From a socio-economic point of view, the CBA shows that this project could have a potential lifetime benefit. While it requires from €20 mln to €50 mln of investment upfront, depending on the selected technology savings are made in OPEX due to lower losses and less downtime. These estimates are based on bottom-up approach and account for primary and secondary equipment, as well as OPEX and land cost. It is believed that if engineering and design, negotiations about manufacturers vs TSO liabilities, and financing consideration begins in 2021 year, the project can be successfully implemented before 2028.

There is a potential to apply for Connecting Europe Facility (CEF) funding both for the engineering works, as well as for the actual component procurement given that this is an innovative project. In order to be realized, this project will require external financing from the EU in order for TSOs of Sweden and Germany to opt for it. Without such an assurance, it is unlikely to be realized. The primary value of this project for the realization of future multi-terminal and meshed grid is the first real life implementation of DCCB, simplified multi-vendor environment and DC meshing. By implementing it onshore, the novel elements can be tested in an inherently lower-risk environment and at lower cost.

3.4.2 WINDCONNECTOR DC PROTECTION

For the DC protection of WindConnector it is suggested to install a DCCB on the cable connecting two offshore wind platforms so that the faults on any side do not propagate to the other one. PROMOTioN has focused on the analysis of dynamic phenomena which would occur in case of DC faults on the hybrid cable between two offshore platforms and on the potential gains enabled by DCCB. Additionally, an overview of procurement and interoperability issues was summarized based on the insights and opinions provided by Dutch TSO, TenneT. Finally, PROMOTioN has participated in the discussion about legal & regulatory status of the assets (exemption, versus hybrid assets versus small bidding zones model), and carried out an analysis on different market schemes, i.e. offshore and onshore bidding zones, which are relevant for WindConnector. This is however included in the main Short Term Projects deliverable and will not be showcased here.

Similar to the SWL-HPB, this project proposes a DCCB but installed offshore. Based on a high-level cost estimate, added costs for DCCB and extra space on the platform may reach up to ~€120 mln. This is a rough estimate which could be improved by having more insight into the costs of offshore platforms and supplementary equipment needed to enable DC protection. In the proposed topology, the necessity of a DCCB is not convincing. As such and due to the fact that this is an offshore project, it might be even harder to persuade TSOs to opt for its realization. Incentives from the EU would be required and a clear goal of testing new technology, as stakeholders assess benefits from DC breaker as compared to its costs as minimal. Potential for CEF funding is to be investigated further, but in any case support will be necessary for this to be considered. The timeline for this project is for it to be constructed before 2030.

It is recommended that project stakeholders assess the potential of offshore DCCB for WindConnector further and in more detail.

3.4.3 BORNHOLM ISLAND CLEANSTREAM ENERGY HUB

Out of the three Short Term Projects, CleanStream is the most advanced and ambitious project due to the fact that it is not an add-on but a full-scale meshed multi-vendor DC hub. If realized, it would address most of the existing barriers to large scale offshore wind deployment – DC protection with DCCBs, multi-vendor and multi-purpose systems, regulatory and economic models. PROMOTioN has conducted a pre-feasibility analysis on these aspects and drafted best practices for project promotors, developers and TSOs for its implementation.

It is important to note that CleanStream is at a very early stage, so it is easier to develop a design which will allow for new technical solutions. This energy hub is located onshore, on the existing Bornholm island so it imposes fewer risks for new technology and no space constraints. Both interconnection and OWFs are already planned so there is commitment from the related parties. What is needed is to incentivize a more innovative approach which promises significant increase in socio-economic welfare as it is shown in PROMOTioN. This project has to be seen as a typical building block for the full-scale, future DC grid. It is believed that first parts of the project can be in place by 2030.

3.5 SUMMARY

The projects described above give Europe the opportunity to test different, albeit simple elements, of multi-terminal DC technology in an industrial situation. In applying the technology in these relatively simple situations albeit of progressive complexity:

1. the technology is demonstrated,
2. experience and learning around the technology in an industrial setting is gained, potentially to reduce short term costs/increase benefits,
3. the European development of HVDC hardware is raised; and
4. ultimately the development of the offshore energy sector is advanced.

These projects are also an opportunity to test legal, regulatory and market models for multi-terminal HVDC assets.

The findings from these short-term projects need to feed into a wider strategy for multi-terminal and meshed HVDC technology deployment (i.e. assets constructed need to be extension ready) and wider legal, regulatory and market frameworks for multi-terminal networks. This will require a longer-term view of planned and existing projects than are currently seen in the TYNDP, and a change in approach from today where each project – regardless of whether they are built by the same European TSOs or by offshore wind farm developers in the UK - is designed and built as a single standalone project and scaled to serve a specific solution. New projects need to consider future extension to additional (more distant) OWFs or may need connection to adjacent hubs to improve path redundancy.

4 DEVELOPMENT OF A MESHED GRID

As described previously, PROMOTioN has examined how offshore wind power could be evacuated most efficiently. This chapter first describes the development of each of the concepts out to 2050 in 5-year segments, based on the modelling outputs described in Deliverable 12.2. It then sets out the technical, legal, regulatory, financial, market and governmental recommendations to deliver an efficient multi-terminal offshore network based on the development of the grid concepts.

To date, point-to-point and early radial multi-terminal HVDC systems have been implemented under a single vendor, single purpose and often single owner paradigm. In these types of projects, the project characteristics such as technical ratings can be optimised and fine-tuned for the specific application they serve. Often, this approach cannot be extended or connected to another HVDC link easily or without loss of performance as they have different technical characteristics, different purposes and different owners.

In Section 4.1 the topology development of the four different grid concepts is presented – Business as Usual (BAU), National Distributed (NAT), European Centralised (HUB) and European Distributed (EUR). The topology development inherently assumes the ability of existing projects to be extended with additional circuits or to be connected to other existing or new projects, without loss of technical & financial performance i.e. the need for large CAPEX investments on existing or already planned point-to-point infrastructure (this will require some anticipatory investment on any new platform to be extendible). It assumes that the grid is capable of evolving continuously and organically by adding new links and terminals in a staged delivery to meet a continuously changing transmission need.

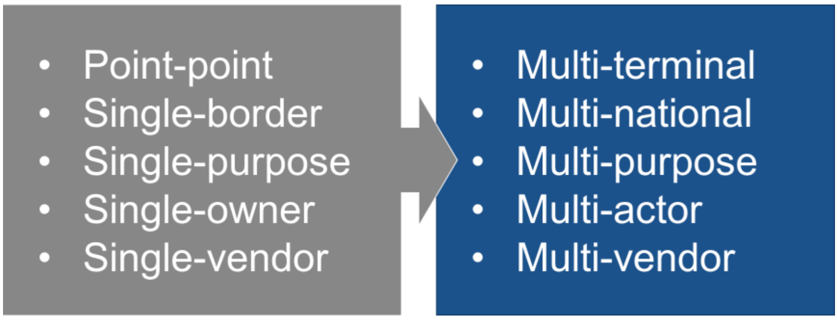


Figure 12 - Required HVDC system development paradigm change

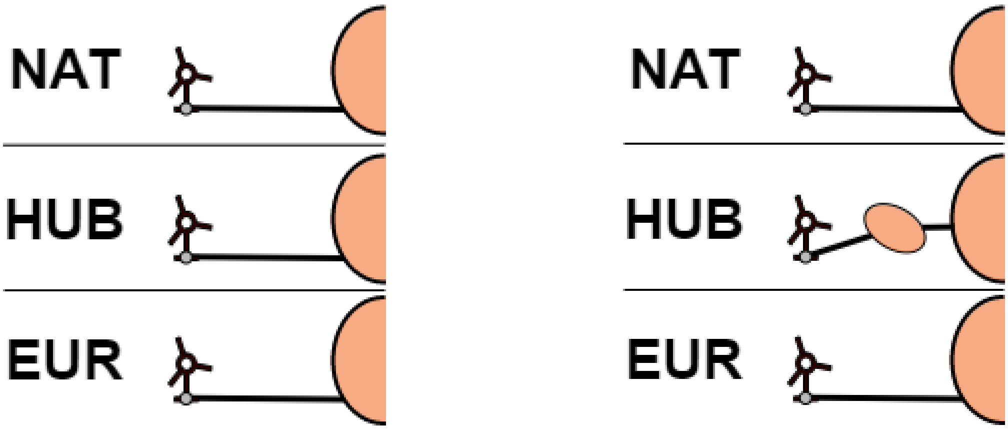
In order to assure a competitive environment driving costs down and improving performance, each of these incremental additions could have different owners, different vendors, different technologies and different purposes, without it being centrally planned a priori. In order to allow such a multi-purpose, multi-actor, multi-vendor, multi-national MOG to develop, the assumption of compatibility needs to be turned into reality through the formulation of a set of explicit technology and purpose-agnostic minimum requirements which all actors in the MOG development need to adhere to. This paradigm change requires coordination on many different aspects and levels. Many of the preconditions to solve the multi-national and multi-purpose aspects are legal, regulatory, economic or financial or even market or governmental in nature and are covered by Work Package 7 and reported in Sections 4.2, 4.3 and 4.4 of this report.

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 the concepts is displayed only for the sections of the grid that are typical to that concept in the High wind scenario. This means that all point-to-point connections of wind are not displayed, as these are considered business-as-usual. The High wind scenario is chosen as this scenario best illustrates the differences between the concepts as the grid develops over time. However, in general, each concept in each scenario shows distinctive development according to the philosophy of that concept. This is further explored in Deliverable 12.2.

Each display of the grid development in the following section only shows the typical topologies for each concept. As the location and size of the OWFs are an outcome of the development of the offshore wind scenarios[17] (and not influenced by the grid concept), each representation therefore shows the same OWFs, all connected according to the philosophies for each concept.

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 point-to-point connected to the grid in all three concepts is also not displayed, as this OWF does not represent the design philosophy of these different concepts (Figure 13a). Additionally, any OWF that is first connected to an island in the HUB concept before being brought to shore and is point-to-point connected in the NAT and EUR concept is also not displayed (Figure 13b). This is because, effectively, this OWF is point-to-point connected to shore, only the support structure for its HVDC converter is different. By excluding these OWFs from the representations only those OWFs are shown that are included in meshed or multi-terminal grid topologies. 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.



a) An OWF that is connected point-to-point in each concept.

b) An OWF that is connected point-to-point in NAT and EUR and through an island in HUB

Figure 13 – Schematic overview of an OWF that is not connected according a distinctive development and will thus not included in subsequent figures.

It must be noted that the grid developments displayed are only those that have been modelled in the topology generation of Deliverable 12.2. This includes the modelling of evacuating wind to shore and interconnection possibilities between countries. These therefore are the OWFs modelled in the generation scenarios on top of

[17] Refer to Deliverable 12.2 for the underlying methodology to the placement and size of each OWF.

existing OWFs that are either deployed or approved and under construction by 2020, which is the point at which PROMOTioN's scenarios are established. These OWFs total 19.6 GW, as was previously shown in Table 5.

4.1.1 2020 - 2025

At the start of the period the concepts already diverge significantly. 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.

Technically, these offshore grids pose some minor challenges as described in Section 4.5. There is some connection between platforms or artificial islands, which may be the most challenging configuration to construct. The coordination and planning of these grid elements, as well as the rate of construction are areas to consider carefully in this period. The design of new platforms should reflect future needs and potential grid extension. If meshed or multi-terminal grid elements can be forecast, some anticipatory investment may be required to facilitate this (e.g. Platforms with space for interconnection to additional sub-stations or cables). The following challenge will be related to interoperability, where it might prove difficult to connect multiple technologies of different manufacturers. The multi-terminal situations that these create do not pose any problems on the protection side as the rating of the connected cables remain below the maximum infeed loss of the connected areas. The conclusion in PROMOTioN is that HUB construction may result in lower investment in areas of high wind. HUBs are likely to cross into several EEZs. If the EC and Governments wish to steer development towards larger power concentrations and island solutions offshore, then PROMOTioN considers that increased cooperation will be required between countries and stakeholders to plan and organise wind locations and planning to allocate larger areas for wind generation. This may be achieved through an increased mandate for supranational organisations such as the North Seas Energy Cooperation (NSEC), which has support groups defining spatial planning and coordination of offshore tenders. While the NSEC is a Government platform, it operates through extensive consultation with the multiple stakeholders. This stakeholder participation is considered essential. Anticipatory investment will only be realised with alignment of ambition between cooperating states. In the HUB concept, an OWF is built in Belgium that will be connected with a hybrid interconnector by 2030 (described in the next section). This entails anticipatory investments necessary to connect this cable. In the PROMOTioN HUB concept four islands are already constructed in this period. In reality, these islands are likely to still be in the planning and design phases by 2025, but optimally they are already constructed.

As much of the offshore grid is still similar to the current offshore grid, many current regulations remain applicable in this period. However, as a minimum, bilateral agreements will be required to agree the regulatory framework and/or the support scheme for the connections of OWFs that are not connected to their 'home country', i.e. the Dutch OWF that is only connected to the UK in the 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 have been agreed.

While it is anticipated that in some cases bilateral agreements are inevitable, PROMOTioN recommends early adoption of new Regulatory and Legal and Market frameworks. The feeling is that bilateral agreements for individual projects will prevent or slow extension of potential grid elements. The proposal in PROMOTioN is to implement the proposals to strengthen the role of the Regional Coordination Centres (RCCs) in operation of North Sea hubs and infrastructure. Similarly, increased responsibility for coordinated longer term project planning may be required by ENTSO-E with requirements set out in a North Sea Treat. Here the bottom up individual projects may be tested against longer term regional plans, both on- and offshore.

The combination of increased cooperation, better and longer term (spatial) planning, clear legal status and a stable regulatory environment and commitment to maintain this will help to reduce overall risks and risks of stranded assets.[18] Further, detailed recommendations are set out later in this chapter.

4.1.2 2025 - 2030

The planning horizon means that the situation in 2030 may 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 interconnected with each other. There is a possibility to do so in AC, because of the distance between within these clusters[19]. The use of DCCBs may therefore be omitted, which is the assumption made within the project (for the purposes of the CBA). Additionally, some meshing takes place in the NAT and EUR concept and even more multi-terminal grids are constructed. Where in the previous period the interoperability of components could still be managed case-by-case, the number of topologies in this period makes that a DC grid code and vendor interoperability a requirement.

In PROMOTioN the construction of islands may become a tangible reality. If the issues described in the earlier period can be solved, an optimal roll-out would include islands being constructed. However, PROMOTioN believes any realisation of islands before 2030 will be difficult[20]. In the modelling results, all six islands on the predefined locations are in the early stages of operation. Some of these already grow to a significant size in this period, as many OWFs are connected to these islands. Some interconnection between the islands is also established, thereby creating large interconnected topologies. 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 Wind Generation Planning, the CBA and Cross-Border Cost Allocation (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.

Again, many current regulations may still apply in this period. However bi- or multi-lateral agreements will be required for the regulatory framework of the hybrid interconnection established in the HUB concept in 2030, agreeing details include transmission owner remuneration and transmission tariffs paid by OWF owners. Agreement and implementation of a suitable market model (i.e. small bidding zones) and compatible OWF support scheme would be beneficial.

[18] In the consultation process, partners also mentioned cross-sector and market coupling as a need to avoid stranded assets. This is beyond PROMOTioN scope.
[19] This is further explored in Deliverable 12.2
[20] There is a plan to build a large hub in Denmark prior to 2030, as well as to utilise Bornholm Island (in the Baltic Sea) as a hub structure. Both projects will need haste to be constructed on time.

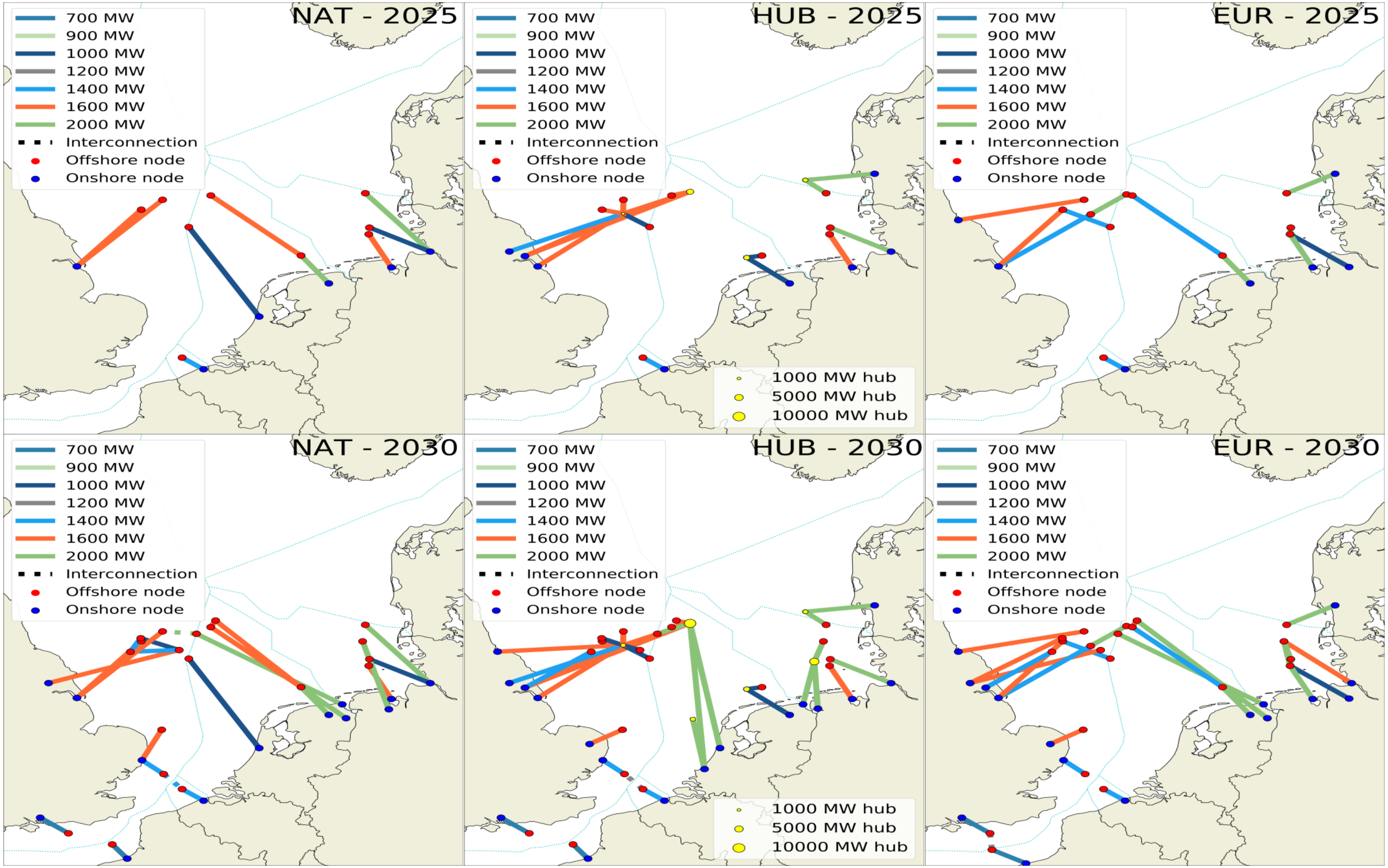


Figure 14 - From left to right: NAT, HUB and EUR representations in 2025 (top row) and 2030 (bottom row).

4.1.3 2030 - 2035

In 2035 the concepts are still similar to the previous period. However, meshing in the NAT and EUR concept for interconnection purposes are on the rise. The HUB concept mostly increases the hosting capacity of the islands. Although there certainly is an increase in generation, most of this generation is connected through point-to-point configurations or connected to the islands and therefore is not shown in Figure 15.

The concepts do not pose any difficult new challenges. Due to that, this period might give room to implement regulations destined for the entire MOG, thereby starting to replace the bilateral agreements. This gives time to evaluate these instruments and improve them where necessary. However, as mentioned above, the earlier the principles of MOG regulation can be agreed, the easier it will be to incorporate bilateral agreements into a wider regulatory structure. If this does not happen, there is a risk that the bilateral agreements cannot be brought into a wider MOG regulatory regime and these assets will not be managed all together.

Given the rapid build out of the grid modelled in the late 2030s, it is strongly recommended that the legal, regulatory and financial frameworks are fully established by 2035. These recommendations intend to create a level playing field for the entire MOG, thereby making separate agreements unnecessary. By the end of 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 small bidding zones market model or a legally binding 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 (Recommended in PROMOTioN to be delivered through an RCC)
- Increase in supply chain capacity and capability to be able to keep up with the anticipated roll-out.
- Continued development of a highly trained workforce to meet demand for offshore work.

4.1.4 2035 - 2040

By 2040, the situation changes drastically in all concepts. Whereas the amount of meshing and multi-terminal topologies was quite limited in earlier periods, these concepts now show complex topologies that are interconnected within and between countries. A total of four countries are directly connected through a single topology in the grid in the NAT and EUR concepts: Denmark, Germany, Netherlands and the UK. Several OWFs are also interlinked, thereby creating more complex situations. In the NAT concept another direct link between four countries is established where the UK, Netherlands, Belgium and France are directly connected to each other. In the HUB concept, several of the islands are now connected to each other creating a large amount of possible alternative pathing. This includes the artificial islands in the Netherlands, Germany and Denmark and another island in the Netherlands and the UK.

Due to the added complexity in the NAT and EUR concepts, 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 availability for trade. This protection system protects the onshore grid for a sudden large increase or decrease in power infeed that could disrupt the onshore grid.

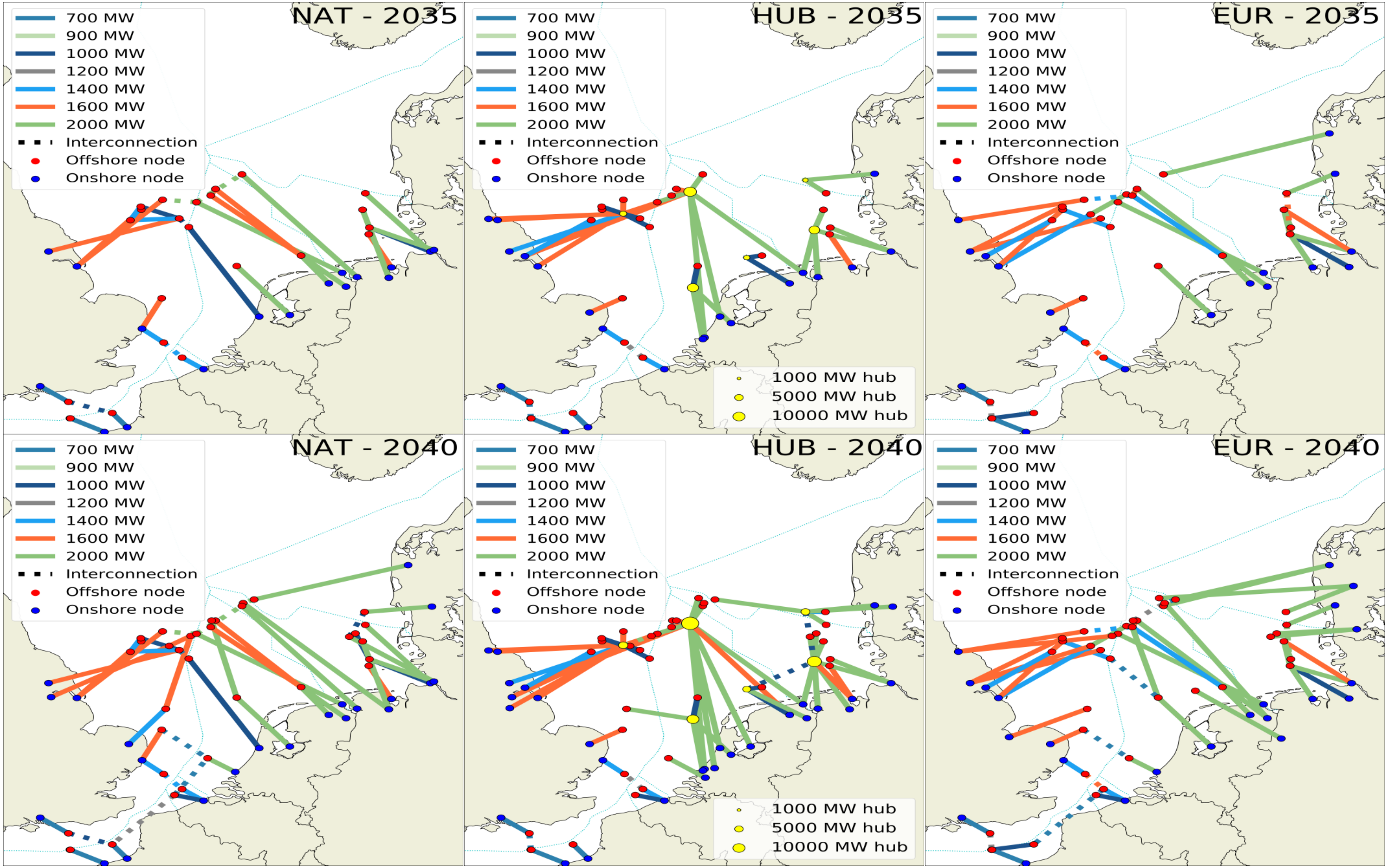


Figure 15 - From left to right: NAT, HUB and EUR representations in 2035 (top row) and 2040 (bottom row).

4.1.5 2040 - 2045

The complexity continues to increase in the concepts, with the NAT and EUR concept adding Norway to form a five-country grid topology in the North of the North Sea. The connected capacity of OWFs is increased in this topology, increasing its complexity. In the NAT and EUR concepts, more multi-terminal and meshed configurations are established, also adding to its complexity in operation. Although possibly not required, it might be necessary to apply DC/DC converters in the multi-terminal and meshed systems to control the power flow. These components allow the steering of DC power to wherever it is required, necessary due to the fact that the increased complexity requires more control over the power flow. However, the need for this will need to be assessed leading up to this point.

All essential recommendations should have been carried out at this point, leaving no additional recommendations to be implemented. Technology is now relatively mature, albeit there should be room for continued innovation and cost reduction. 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.

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 makes the EUR concept the most expensive concept to construct, mostly due to its platform extensions and its need for DCCBs, despite the reduction in cable length. However, this also brings many benefits, as was discussed in Chapter 2.

The HUB concept reinforces some of the existing interconnection between the countries by 2050, thereby creating a large interconnected topology 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 NAT concept, although showing similarities to the EUR concept, has a slightly lower interconnection capacity than the other concepts. 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 and grid infrastructure 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.

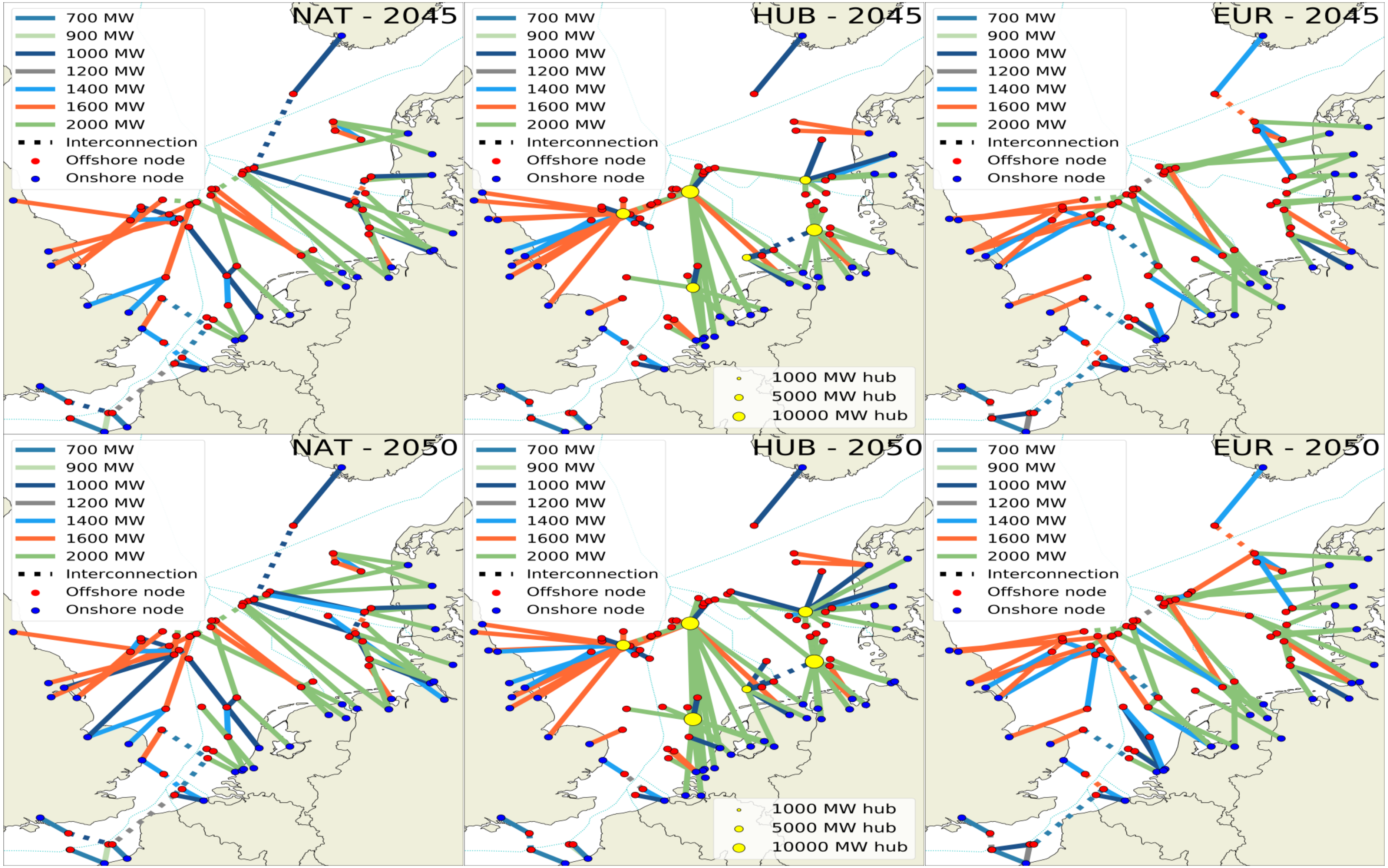


Figure 16 - From left to right: NAT, HUB and EUR representations in 2025 (top row) and 2030 (bottom row).

4.2 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 point-to-point 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. Equally, they provide sufficient clarity and certainty to OWF developers to invest in a pipeline of offshore wind projects.

The development of multi-terminal connections introduces a new type of transmission asset – one which is a connection between two countries to which one or more OWFs are also connected. Deployment of these types of assets results 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 transmission 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? How can the planning of OWFs and transmission assets be integrated or aligned?
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, and how does the market set-up impact how transmission assets are defined and regulated?
    - 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?
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. Further analysis of market models for offshore wind and of wider governmental policy support has been carried out in WP12. This section of the report summarises the WP7 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 from WP7). Sections 4.3 and 4.4 explore market frameworks and government support in more detail.

4.2.1 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.

4.2.1.1 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 a national, rather than EU or international level. If no, the choice between EU and international law can be determined by asking:

- Is it important to have one solution for all states?
- Is the issue only relevant to North Sea coastal states (not to other EU Member States)?
- Did the EU already make use of its competence to legislate on the issue?
- 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 question 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 below and have been considered in all recommendations made in Deliverable 7.2.

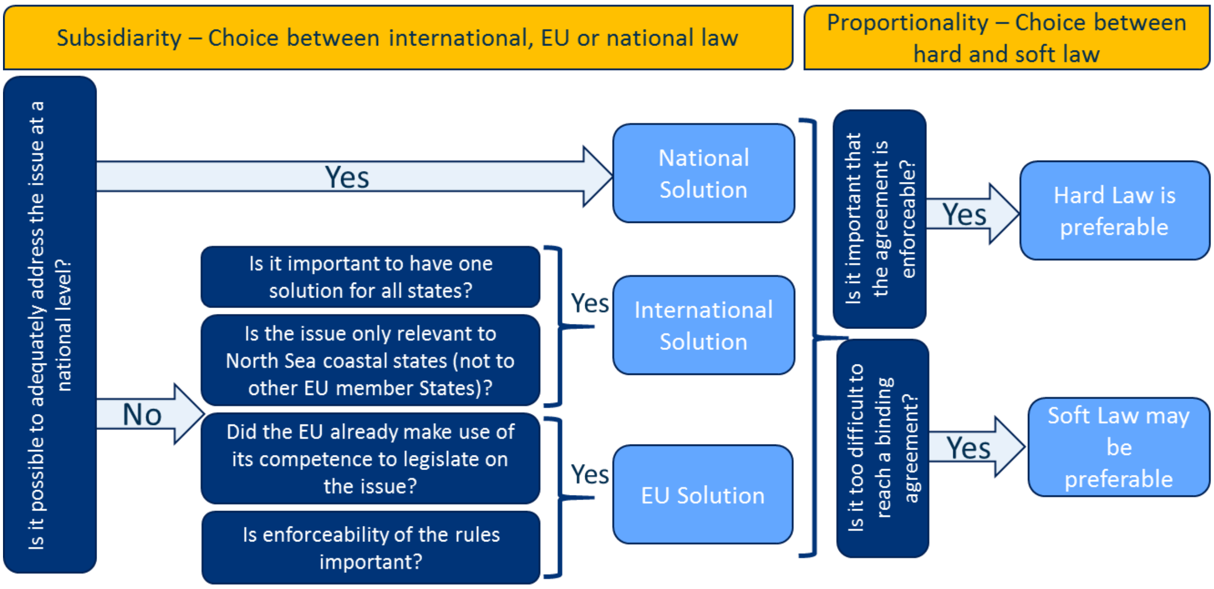


Figure 17 - Decision tree for identifying the most suitable legal instrument (from Deliverable 7.9).

4.2.1.2 DEVELOP A MIXED PARTIAL AGREEMENT ("NORTH SEA TREATY") FOR REGIONAL COOPERATION

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 (or "North Sea Treaty") 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 North Sea Treaty (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 aspects of the proposed mixed partial agreement are discussed later in this chapter.

4.2.1.3 CREATE A ROBUST LEGAL DEFINITION OF 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 point-to-point 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

Subsequent analysis of market models carried out in WP12 (see Section 4.3) has concluded that, if a small bidding zone model were introduced across all OWFs connected to a multi-terminal grid, the transmission assets between these zones may be classed as interconnectors, thus negating the need for a definition of offshore hybrid asset. However, neither the small bidding zones model, nor the use of a bespoke regulatory regime for offshore hybrid asset, has been tested on a multi-terminal offshore project in Europe. Therefore, PROMOTioN recommends progressing with both options before selecting the preferred choice.

DEFINE ‘OFFSHORE HYBRID ASSET’ AT AN EU LEVEL

Under the current market model, where bidding zones are based on EEZ boundaries, a definition of an offshore hybrid asset is necessary because there are legal uncertainties in EU law about whether cables of a multi-terminal and meshed 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 regulatory regime under which the hybrid assets fall is unclear. Asset classification in EU law (regulatory level) is more specific than international law (jurisdictional level), and the categorisation of the cable influences how the assets are regulated in terms of conditions for access, income (tariffs) and ownership.

The lack of a legally-binding definition of hybrid assets increases the risk that either additional cables would be laid to circumvent the legal uncertainty, thereby increasing the financial and environmental cost of offshore transmission, 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.***

This definition would work well for three of the four ways in which hybrid assets could be constructed (listed at the beginning of this section). The second option (tee-in) would still pose some difficulties as it would first be classed as an interconnector, before becoming a hybrid asset. However, long term grid planning could reduce the likelihood of a tee-in construction being required; or identify where phased construction may result in a change of asset classification (i.e. an interconnector becoming a hybrid asset) and ensure that the implications of this (from a regulatory and financial perspective) are incorporated into the initial investment decision making process.

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.

DEFINE 'OFFSHORE HYBRID ASSET' AT AN INTERNATIONAL LEVEL

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.

Consensus between the North Sea states on how the international definitions should be interpreted in the context of the MOG gives these assets a more stable legislative basis.

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 4.2.1.2. 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 is identified as a longer-term aim. However, as it takes longer to achieve, it is important to start negotiations on this matter with sufficient time.

4.2.2 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 multi-terminal and 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 [12]. However, it does not yet provide a roadmap for a multi-terminal and meshed offshore network based on the grid concepts considered in the PROMOTioN project.

The Economic Framework (Deliverable 7.4) identified three key aspects of current planning regimes where changes could help to deliver a multi-terminal and 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 and when do they need to be connected to shore). This also helps to identify anticipatory investment need. Funding anticipatory investment is addressed in Section 4.2.3.1.
- Cost Benefit Analysis (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.

Note that further more technical recommendations towards a type of Network Options Assessment are given in section 4.5.1.3.

4.2.2.1 DEVELOP LONG-TERM PROJECT PIPELINES AND ENABLE TIMELY GRID CONNECTION

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 in Deliverable 7.4 covered three elements of onshore-offshore coordination: (1) Siting new wind farms; (2) Grid access responsibility and; (3) Grid connection costs. (1) and (3) are covered below; (2) is covered in section 4.2.4.3 on grid ownership models.

ADOPT A ZONED OR SINGLE-SITE APPROACH TO 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.
- **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 to build a wind farm. Unlike the zoned approach below, in a single–site approach the development is location specific.

- **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. This approach incorporates elements of the two approaches above. The developers can select the final location of the wind farm within the zone (subject to receiving the necessary planning permissions) giving them some of the flexibility permitted within the open-door approach, whilst still allowing for a degree of long-term certainty on OWF location.

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 4.2.1.2).

ALIGN ON CONSISTENT GRID CONNECTION COSTS METHODS

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 between countries, and technologies, will remove market distortions affecting the location of OWFs, and their rate of roll out relative to other technologies. A super-shallow approach may be the easiest approach to regulate as the meshed network become increasingly complex: 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 4.3), 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 legislature, in consultation with the regulator of the MOG and other stakeholders. 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, point-to-point connected wind farm may be different to that of a wind farm in the same EEZ but connected to the MOG).

4.2.2.2 ADAPT COST-BENEFIT ANALYSIS METHODS TO SUIT MULTI-TERMINAL PROJECTS

Barrier (1): Proposed interconnector projects (or other Projects of Common Interest (PCIs)) 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 previous ENTSO-E CBA methodology[21] 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 (and between grid and OWF 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.

[21] The ENTSO-E methodology has been updated since the time of writing

- 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 baseline 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 more clarity and consistency across the CBAs undertaken as part of its development.

Barrier (3): There is a 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.

4.2.2.3 STREAMLINE PLANNING AND PERMITTING PROCEDURES

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 multi-terminal and 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. Planning and permitting certainty also remains a key issue in the risk assessment by potential grid developers and impacts project risk and thus cost. 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.

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.[22] This means that cross-border projects may

[22] 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.

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 consider 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 4.2.1.3): 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.

Allow for technology-agnostic planning (WP12 recommendation): The development and planning process for offshore transmission assets can take a number of years. During this timeframe substantial technological progress could be made. By including some flexibility within planning permits to allow for technology developments, projects can deliver the most cost-effective solution available at the point the design is finalised, not at point planning permission is first applied for.

4.2.2.4 ENCOURAGE 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.

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.[23]

[23] 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.

4.2.3 FINANCIAL FRAMEWORK - INVESTING IN MULTI-TERMINAL AND MESHED OFFSHORE GRID TRANMISSION ASSETS

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 levels 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.

4.2.3.1 AUTHORISE APPROPRIATE 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: The decision to allow anticipatory investments must weigh up the potential cost saving of the anticipatory investment (compared to the cost of incremental expansions) with the likelihood that the anticipatory investment will be utilised. A MOG will almost certainly require some form of anticipatory investment (e.g. in over-sized 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.

Specifically, the PROMOTioN short-term project on the Ijmuiden Ver WindConnector (see Section 3.4.2) proposes to use an offshore platform that can easily be expanded to accommodate a DCCB and/or an additional DC cable. This requires an anticipatory investment. Due to the lead-time on this project, it is proposed that discussions with regulators start in 2020 to allow construction to start by 2025 (completion in 2027).

Recommendation (short term): Use EU financial support, such as the Connecting Europe Facility (CEF) 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 necessary cross-border anticipatory grid investments that national governments alone cannot deliver (see also Section 4.2.5.4 on CBCA).

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

4.2.3.2 ALLOW 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. These 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.

4.2.3.3 ESTABLISH A 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: In the short-term, liabilities may be agreed contractually between OWF developers and those responsible for constructing transmission assets. However, longer term, 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). This liability regime should determine the extent to which these payments can be passed to consumers through electricity bills.

4.2.3.4 ENABLE ALTERNATIVE FUNDING STRUCTURES AND FINANCIAL INSTRUMENTS TO ENSURE SUFFICIENT INVESTMENT CAN BE ACCESSED

Barrier: Delivering sufficient transmission infrastructure to meet the needs of projected offshore wind deployment rates will require several tens of €bn of investment over the next 30 years. Financing models will need to accommodate different types of investors and different financial structures.

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 is unlikely to be practicable to finance the scale of investment required off-balance sheet or through public funds alone.

Recommendation: Diverse financing structures and financial instruments should be used 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 Offshore Transmission Owner (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.

4.2.3.5 ENABLE INNOVATION IN DEVELOPMENT

Barrier: Some North Seas countries include funding for innovation in the price controls of their TSOs, whilst others have introduced competition in the design and development of offshore transmission assets. However, some countries have adopted neither approach. In addition, legislation relating to transmission networks can be a barrier to deploying innovation on the grid.

Importance for MOG: The deployment of multi-terminal and 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): Use EU financial support (e.g. CEF) 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. Encourage investment in innovation either through competition or price control incentives.

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.

4.2.4 REGULATION OF THE TRANSMISSION NETWORK

Deciding who regulates the MOG is a key prerequisite of the regulatory framework. From there, 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. It has 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 WP7 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?

4.2.4.1 ENABLE NATIONAL REGULATORY AUTHORITIES TO COOPERATE TO REGULATE 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: 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 18)

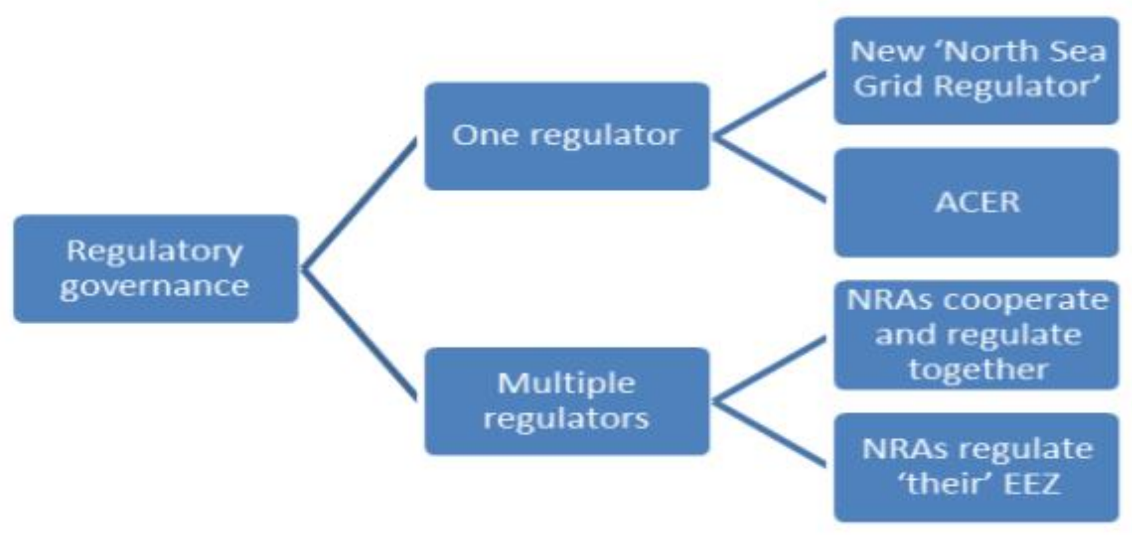


Figure 18: Overview of regulatory governance options (Deliverable 7.2)

Recommendation: 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 coordinate the agreement 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., working with policy makers in other national ministries where necessary. Such cooperation can evolve over time, if coastal states are willing to increase the amount of cooperation, this could eventually lead to the creation of a de-facto North Sea Regulator.

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

4.2.4.2 PROCEDURAL AND LEGAL CERTAINTY

The legal framework for a MOG 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, depending on the contracts that apply.
- 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 Court of Justice of the European Union (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 considered in an international agreement on the MOG.

4.2.4.3 OWNERSHIP MODELS FOR THE MESHED OFFSHORE GRID

The ownership model for MOG 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 8 below. System operation is considered in Section 4.2.4.4.

Table 8 - Ownership models for a MOG.

	MODEL	CONSTRUCTION*	OWNERSHIP	ASSET MAINTENANCE
A	North Sea Grid TSO[24]	NSG TSO		
B	Continuation of existing national ownership models	National Transmission Owners (TOs), or OWF developers as is currently the case in the UK.	National TOs or OFTOs[25] (in the UK)	National TOs or OFTOs
C	Tenders before Construction	OFTO or OWF developer. appointed by a system planner or planning bodies	OFTOs (Could be an existing TSO)	OFTOs (Could subcontract back to the developer)

[24] In this case Transmission System Owner and Operator
[25] Offshore Transmission Owner

	MODEL	CONSTRUCTION*	OWNERSHIP	ASSET MAINTENANCE
		across North Seas Countries		
D	Built by a North Seas Grid ISO, tendered to third parties[26]	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)	All assets tendered to third parties post-construction	Asset Owner (Third Parties). Could subcontract back to the OWF developer where applicable.

*Regardless of who the party responsible for constructing the assets is, they will need to work with the onshore transmission network owner to agree upon a suitable connection point. If the offshore connection is not built by the OWF developer, they could face penalties for late delivery. Similarly, the onshore TO could be penalised for late delivery on any onshore reinforcements.

Each approach was assessed against its ability to deliver a net economic benefit and attract third party investment/private capital. The views of stakeholders were also sought. All models were considered feasible provided that they were appropriately regulated such that transmission owners received commensurate remuneration for their services and there is clarity on their liabilities. 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 – Centralised approaches were considered more likely to deliver investments with a high level of technical standardisation and interoperability and have relatively low regulatory complexity (once established) since only a single entity is responsible for (large portions of) the whole grid. The lack of competition may though ultimately slow down the learning curve cost effect. In addition, they may be expensive and time-consuming to establish. 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, driving down costs. However, under competitive and co-operative approaches where several owners co-exist (models B to E), mechanisms for coordination of efforts will be 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 (where this competitive pressure is passed down the supply chain), but the third parties bidding may not be able to deliver the economies of scale possible compared to when construction is concentrated amongst a few parties[27].

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[26] Independent System Operator

[27] 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)**. Similar conclusions were drawn in an Orsted-commissioned report on the relative merits of developer-built and TSO-built assets (**https://diw-econ.de/publikationen/studien/orsted-offshore-wind/**). 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/**). A detailed comparison of methods across all three documents has not been carried out in PROMOTioN

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 greater detail in the section on the financial framework (Section 4.2.3). 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 developed in the best way from a regional perspective. With regional ownership of the grid and national regulation, there may be perverse 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.

4.2.4.4 ESTABLISH A REGIONAL COOPERATION CENTRE FOR 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 element between synchronous areas are HVDC interconnectors, which, in very simple terms, can be operated as 'electricity pipelines' between synchronous areas[28]. 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, therefore 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. It should be noted that the mandate of the RCCs set out here may require additional legislative powers.

4.2.5 REVENUE MECHANISMS FOR OFFSHORE WIND FARMS AND TRANSMISSION OWNERS

In a MOG, 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

[28] 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.

deliverables 7.2 and 7.4 (legal and economic frameworks). Section 4.2.5 and Appendix V look in more detail at the market arrangements which could determine the revenue of OWFs and provide further details on how the administration of support schemes for OWFs may differ under different market arrangements.

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).

4.2.5.1 DEVELOP GRID-WIDE 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 who seek government support (as opposed to a merchant approach), 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 capture price of OWFs and, thus, to what extent developers need extra support or risk sharing mechanisms in order to develop OWFs.

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” to 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 develop renewable energy projects. These countries can be either EU Member States or third countries. The countries negotiate who pays for the subsidies received by the joint project. 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 MOG, 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 MOG is not 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 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.

4.2.5.2 ALLOW 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 regulated 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.

Revenues and incentive structures should be structured such that they incentivise 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 where typically the OWF developer builds the assets and transfers it to an OFTO.

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.

4.2.5.3 ALIGN ON THE 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 provide 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, at the time of writing, it has yet to be determined whether non-EU member states would have voting rights, or simply be observers [13].

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.

4.2.5.4 FURTHER DEVELOP CROSS-BORDER COST ALLOCATION METHODS FOR MULTI-TERMINAL PROJECTS

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.

4.2.6 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 MOG 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)

4.2.6.1 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 European Economic Area (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 Section 4.2.1.2). 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.

Note: current network codes do not yet cover the HVDC system itself. These network codes have to be developed and adopted as a matter of priority as discussed in section 4.5.3.1.

4.2.6.2 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.

4.2.6.3 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.

4.2.6.4 SYSTEM OPERATION GUIDELINES AND EMERGENCY AND RESTORATION CODE

The System Operation Guidelines (SOGL) set 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[29], it is not yet clear if the dimensioning of reserve capacity onshore will be bound by the criteria expressed in the SOGL. It is 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.

Furthermore, it is recommended to revise the current SOGL to include HVDC specific operational guidelines, as further discussed in section 4.5.1.1.

4.2.6.5 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)[30]), 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)[31].

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 9 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.

[29] 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.
[30] BSP – A provider of balancing capacity. The time duration and quantity of capacity provided will be agreed in contracts with the System Operator.
[31] 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.

Table 9 - Summary of the current balancing mechanisms regulation from the three perspectives.

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

- **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 9) 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 (EB GL) 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 markets is a desirable outcome.

4.2.7 DEVELOP CONSISTENT DECOMMISSIONING GUIDELINES FOR OFFSHORE ASSETS

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 makes it difficult to assess the total cost of decommissioning for cross-border projects and adds administrative costs. Decommissioning guidelines intended for use on point-to-point 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 farm 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[32]. The research in PROMOTioN identified knowledge gaps in the understanding of the environmental impact of decommissioning OWFs and offshore electricity cables. To inform future guidelines, further research into these topics is necessary.

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

4.3 RECOMMENDATIONS ON MARKET MODELS

4.3.1 INTRODUCE THE SMALL BIDDING ZONES MARKET MODEL

4.3.1.1 EXTENDING NATIONAL PRICE ZONES NOT NECESSARILY THE BEST SOLUTION FOR OFFSHORE WIND

When a MOG is developed in the North Seas and OWFs become connected to more than one single country, it is not given that the best choice is to pay them the electricity market prices of the countries in whose Exclusive Economic Zone (EEZ) they are located. This is because the generated power may not always flow to the countries in whose EEZ 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[33]. In an increasingly multi-terminal and meshed offshore grid, this may require that the produced energy is routed differently than directly from the EEZ in which an OWF is located to that country. From this perspective, different market designs for OWFs in a multi-terminal and meshed grid are studied.

The extension of **national price zones** into the EEZs, which is considered the default market design, is compared to the creation of **a single offshore price zone** market design and a market design that consists of **small price zones** that are separated by the occurrence of network congestion. The national price zones market design leads to difficult dilemmas and potentially high costs for TSOs. A single offshore price zone can solve some of these dilemmas but also leads to others, such as how to define the borders of the single zone. Small price zones are economically efficient, also with respect to incentives for storage and power-to-X, but may lead to lower OWF revenues. Providing the OWF owners with financial transmission rights or put options can improve their revenues, thereby reducing the need for financial support. It should be noted that, whilst this analysis was completed before the EU's Clean Energy Package came into force, the small bidding zones model is aligned with the target model for the EU electricity market set out in that legislation.

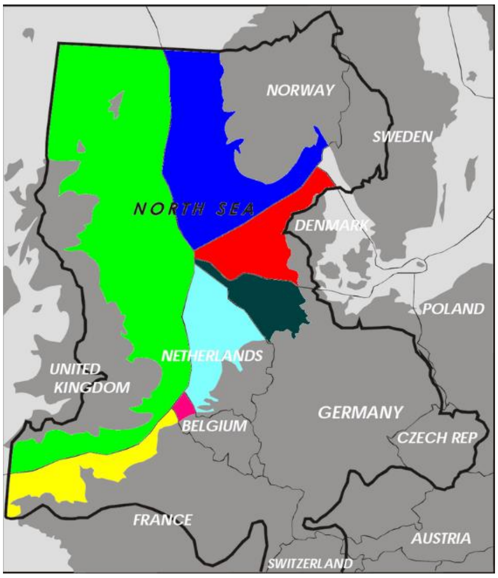

Figure 19 – North Sea Economic Zones. (Source: https://en.wikipedia.org/wiki/File:North_sea_eez.PNG)

The market designs are illustrated with simple, graphical examples and compared on their performance with respect to economic efficiency and wind park revenues. Factors such as social acceptability (fairness), feasibility, transaction costs and transparency will also play a role in practice, but this study is limited to economic efficiency and the feasibility in the European legal context.

The following assumptions are made in the analysis:

- The variable operational costs of wind parks are zero.

[33] 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).

- The DC technology used for the transmission of electricity enables full control over the power flows.
- There is no congestion within the onshore price zones in the examples; i.e. congestion between onshore price zones is handled completely efficiently.
- Congestion between price zones is handled through a form of auctioning.
- There is no abuse of market power, i.e. no strategic behaviour.

Given the above assumptions, the short-term economic efficiency (i.e. dispatch efficiency) of the MOG is maximised if the dispatch of wind energy is maximised, given demand and grid constraints, and the electricity that is generated offshore is transported as much as possible to the countries with the highest prices. All market designs can achieve these goals simply by maximising wind generation and moving the power to the most expensive onshore price zones, but the national price zone model may give incentives to the contrary.

If economic efficiency is achieved, the only remaining impact of the market designs is in the distribution of income between the OWFs and the TSOs. Market designs that lead to higher congestion rents in the MOG provide correspondingly lower revenues to the OWF operators, thereby increasing the need for financial support.

It is assumed that the capacity of the OWFs is larger than the capacity of the network, i.e. that ‘overplanting’ has occurred. A certain degree of overplanting is economically efficient because it allows for a higher energy output, relative to the available network capacity, at moments of low wind and when some of the wind parks are in maintenance or still under construction. Without overplanting, the network would rarely, if ever, be used at its full capacity, which would mean that an opportunity to produce more wind energy without having to invest in more network capacity would be forfeited[34].

This chapter provides a synopsis of the analysis that is presented in Appendix V. The remainder of this chapter is organised as follows: Section 4.3.1.2 describes a number of options for pricing offshore wind energy and Section 4.3.2 presents simple numerical examples that are used to compare these options. In Section 4.3.3 an analysis is made on the implication of congestion on the revenues of OWF operators. In Section 4.3.4, legal considerations of a changing market design are discussed. Section 4.3.5 provides a conclusion and recommendations for the preferred market design.

4.3.1.2 EXAMPLE SETUP

The market designs are illustrated with examples that are based on network configurations that are deemed likely to develop, namely a ‘WindConnector’ between two countries with wind parks attached and a hub with multiple parks. This is in line with the multi-terminal and meshed configurations that emerge from the topology generation in Deliverable 12.2. Quantitatively, the examples are not intended to be realistic; they are merely intended to demonstrate the key characteristics of the market designs. The examples in Appendix V are different, as their configurations were designed to ‘stress test’ the market designs with more extreme situations.

The example setup has two countries, Country A and B, each with its own price zone. See Figure 20. There are two parks in the North and an energy hub in the South. The energy hub can be visualised as an artificial island or a large offshore platform that connects several nearby wind parks. In the examples, Country A

[34] Overplanting of the grid is only assumed in this particular study in order to show the effects of congestion in each of the market designs. In the topology generation in PROMOTioN it is considered that all wind can always be evacuated. A certain degree of overplanting is closer to reality.

always has a lower electricity price than Country B, but it should be kept in mind that in practice this may reverse regularly.

The market designs will be demonstrated for high and low wind cases. Figure 20 shows a situation with high wind, meaning the turbines can produce at their maximum. Wind Park 2 and the parks around the energy hub have been overplanted, which means that part of their output needs to be curtailed at this time. Figure 21 shows the situation when the parks operate at 50% of their rated capacity. The combined generation of the parks at the energy hub is now only 900 MW, so there is room for 100 MW additional flow towards Country B, the high-priced zone. The cables into Country B are always congested, as the lower price in A leads to trade to B[35]. The export along the southern link leads to a flow of 100 MW from Country A to the energy hub. The fact that the flow is in the opposite direction of the arrow is indicated by the negative sign.

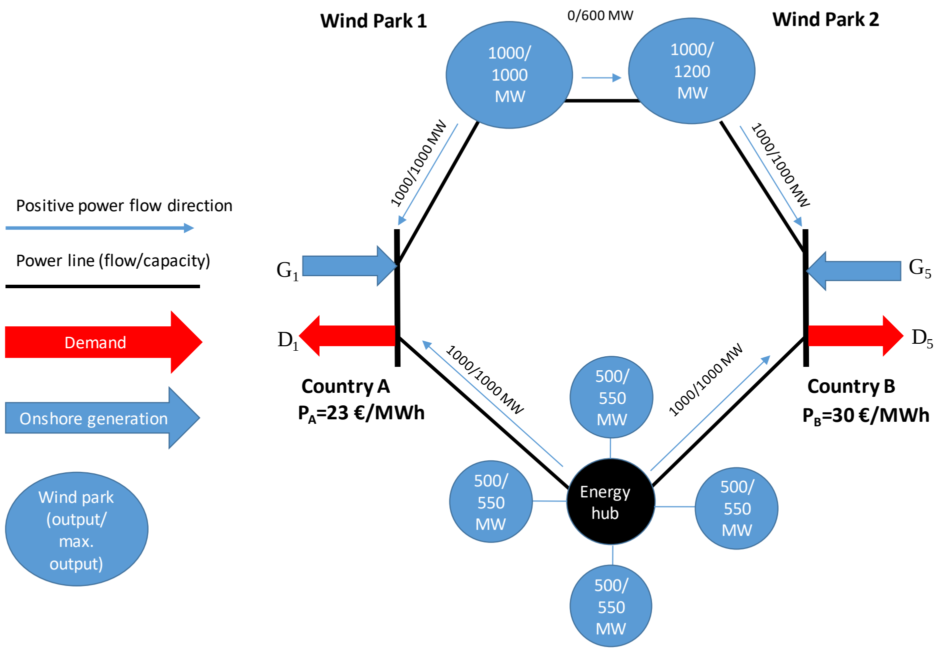

Figure 20 – Example set-up, high wind

[35] It is assumed that the capacity of trade between the countries made possible by the MOG does not lead to price convergence between the countries.

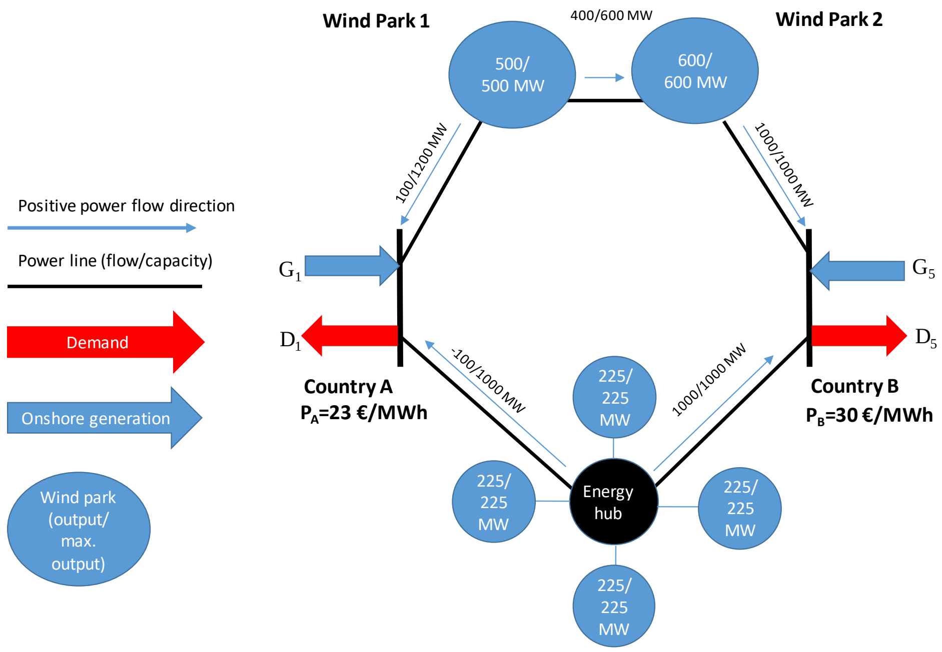

Figure 21 – Example set-up, low wind. N.B. The maximum output of the OWFs is the maximum output under this wind condition, not their rated capacity.

4.3.2 THREE MARKET DESIGNS

4.3.2.1 NATIONAL PRICE ZONES

In this market design, the national bidding zones are extended to include the OWFs in the respective countries' EEZs. Figure 22 presents the situation in the case that the OWFs produce at their maximum capacity. The EEZ of Country A includes Wind Park 1 and the energy hub; the EEZ of Country B Wind Park 2.

The power of Wind Park 1 is sent to Country A and the power of Wind Park 2 to Country B, but Wind Park 2 needs to be curtailed by 200 MW. Wind Park 1 receives the price of Country A and Wind Park 2 receives the price of Country B. It would likely also need to be compensated at this price for being curtailed. As the energy hub is located in the EEZ of Country A, all parks connected to the hub receive the price of Country A. The parks connected to the hub will all need to be curtailed. One solution would be to limit the connections between the parks and the hub to 500 MW each, so the OWFs would be forced to self-curtail. This means they could never cause congestion on the cables from the hub to the mainland. However, this could lead to unnecessary curtailment whenever other OWFs connected to the energy hub would not produce at their maximum. If the cables between the parks and the hub are not limiting, i.e. they have a capacity of 550 MW, this raises the question of which parks should be curtailed.

If there is a power-to-X or energy storage facility at the hub, e.g. a battery or a hydrolyser, it would need to pay the onshore price for electricity, even if it is located next to an OWF that is being curtailed, unless it had a private arrangement with the wind park operator. This relatively high price for excess electricity would discourage the development of such facilities.

The cable between Wind Parks 1 and 2 is the border between the EEZs of Countries A and B. In the optimal dispatch of Figure 22 there is no flow on this cable. However, if the regulation that cross-border flows must be maximised is applied here, this may mean that market parties should be allowed to export 600 MW across this cable from Country A to B. As this would lead to an overload of the cable from Park 2 to Country B, the offshore grid operator would need to counter trade this amount. This would cost the offshore grid operator the price difference multiplied by 600 MW. Alternatively, Wind Park 2 could be curtailed by 600 MW to free up the needed network capacity, but this curtailment is technically not necessary and would therefore cause an unnecessary loss of wind generation. Additionally, as the curtailment price of Wind Park 2 is likely based on the price of Country B this would be a more costly and thus unfavourable solution.

Had the energy hub been located in Country B's EEZ, the cost of counter trading would be much higher. In this case, the generators around the hub would receive the price of B, whereas half the output would be sent to A. Efficient dispatch would therefore require exporting power from a zone with a higher price to one with a lower price. Maximizing cross-border flows from A to B would require a flow of 1000 MW across the border between Country A and the energy hub, while economic optimization would require a flow of 1000 MW in the opposite direction. This would lead to a counter trade requirement of 2000 MW.

In summary, pricing offshore wind parks according to the onshore price of the national EEZ in which they are located raises the following challenges:

- Power conversion facilities such as batteries or power-to-X are discouraged because they have to pay the onshore price, even if there is surplus power from curtailed wind parks available.
- Economically efficient dispatch may require that electricity is traded from a country with a higher price to one with a lower price.
- Congestion of network links within a zone may cause the optimal flow between national price zones to be zero or negative in an economically efficient dispatch of wind power. In such cases, the requirements for maximising cross-border trade can only be met with counter trading.

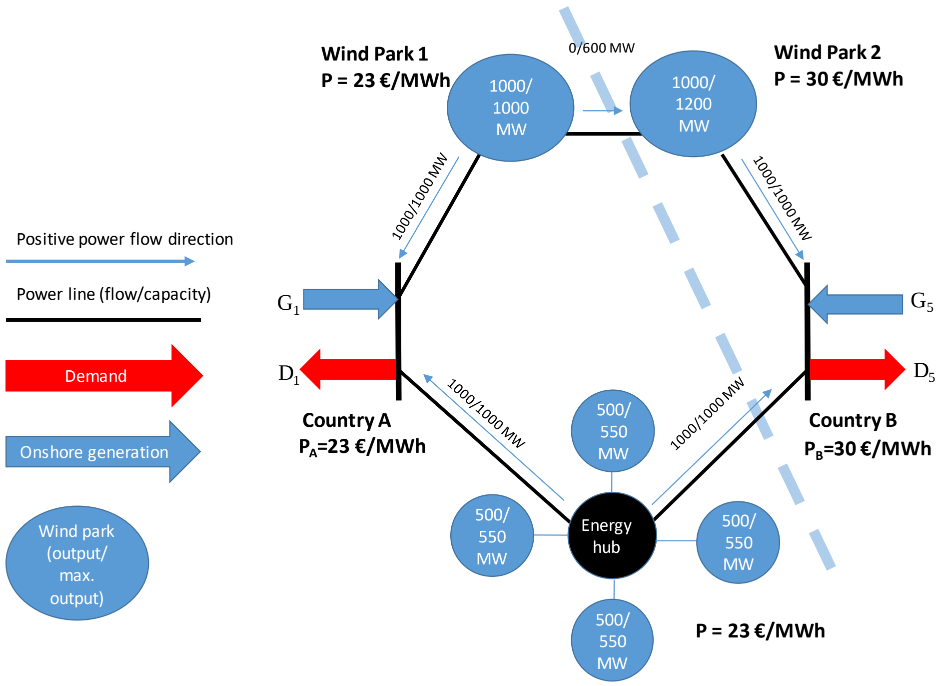

Figure 22 – National price zones model

4.3.2.2 SINGLE OFFSHORE PRICE ZONE

Implementing a single offshore price zone solves some, but not all the challenges of national price zones. Economic dispatch will be the same as in the previous example, meaning that the generated power will be transmitted as much as possible (considering grid constraints) to the onshore zone with the highest price, then to the next highest price zone, etcetera. If the wind generation of the OWF is priced at its marginal economic value, the offshore price will be equal to the lowest onshore price to which power is sold.

In this market design, power is always sold to onshore zones with the same or a higher price. If the offshore price zone's boundaries are considered as borders to EU law, this also means that cross-border flows are always maximised in the direction of the higher price zone. The need for counter trade is thus removed.

This solution does not fully fix the problem of providing efficient incentives, however, as the entire zone receives a single price. If, for instance, there is excess wind generation capacity in the North, but not in the South, this would cause the price in the entire offshore zone to be zero, whereas the marginal value of wind generation in the South would be equal to the price in Country B. The occurrence of this problem increases as the geographical spread of the single offshore price zone increases and generation becomes less interrelated. Consequently, this market design leads to low wind park revenues (and therefore a potentially higher need for financial support) and also distorts the incentives for storage and power-to-X facilities.

The creation of a single offshore price zone also creates a new problem, namely how to define its boundaries. The question is whether the price zone should extend through the English Channel Or even into the Baltic. Inevitably, this will involve arbitrary decisions, but they may have far-reaching impact on the economic performance of the MOG.

4.3.2.3 SMALL PRICE ZONES

These issues can be resolved by dividing the offshore grid into smaller price zones that are defined by the occurrence of network congestion. This option is inspired by 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).[36] Each price zone consists of one or several OWFs with sufficient network capacity between them that there will be no congestion between them, for instance an offshore hub with point-to-point connected OWFs.

The price in each zone is determined by the marginal value of generation in that node to the system as a whole. Again, wind power is evacuated to the onshore market with the highest price first, then the market with the next highest price, etcetera. Therefore, the marginal value of an OWF is the lowest market price at which the energy is sold at any moment. If not all wind energy can be evacuated (in case of overplanting of the parks and high wind) and some wind generation capacity needs to be curtailed, then the marginal value is equal to the variable cost of wind generation. For the sake of this example, this is assumed to be equal to 0 €/MWh, even if the actual marginal costs include some costs of operating and wear-and-tear. Hence, the price in an offshore zone is 0 €/MWh in our examples when there is curtailment[37]. With a price of 0 €/MWh, the OWF 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 OWF.

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[36] 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, 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, a simplified version which we call 'small zones' can be applied to an offshore grid.

[37] An instrument will be presented in Section 4.3.3 that restores the generator revenue in this case without distorting economic efficiency.

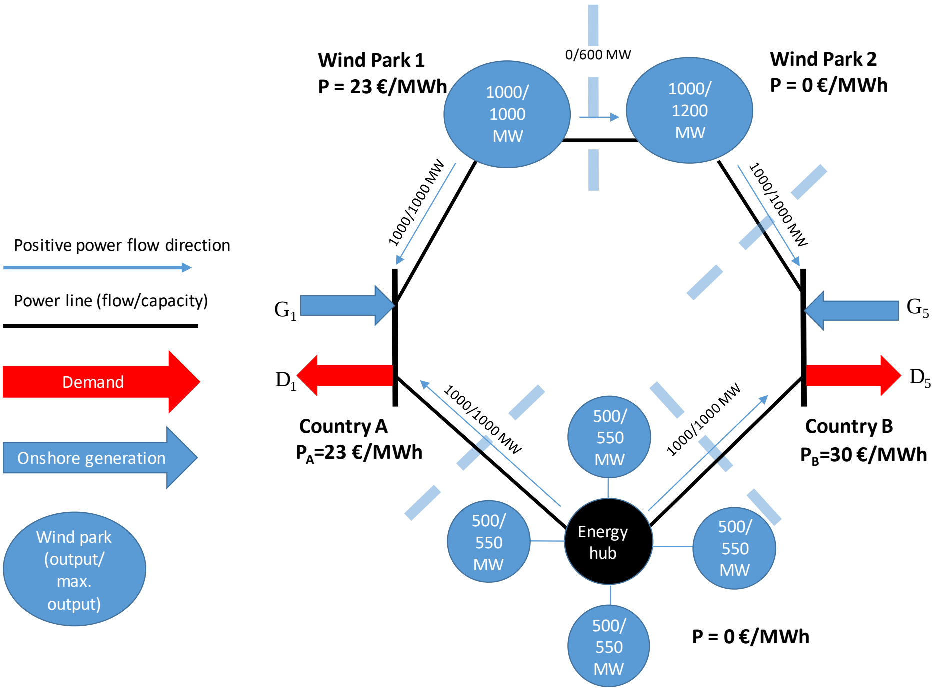

Figure 23 – Small price zones, high wind generation

Figure 23 and Figure 24 present the results for this market design for high and low wind scenarios, respectively. The economic dispatch and the power flows are the same as in the national price zones case: in both cases they are economically efficient. A notable outcome is that in the high wind scenario, the price for the OWFs at the hub and for Wind Park 2 are zero because they need to be curtailed. As the line between Wind Park 1 and Country A is able to transport all wind energy of Wind Park 1, this OWF gets the price of Country A.

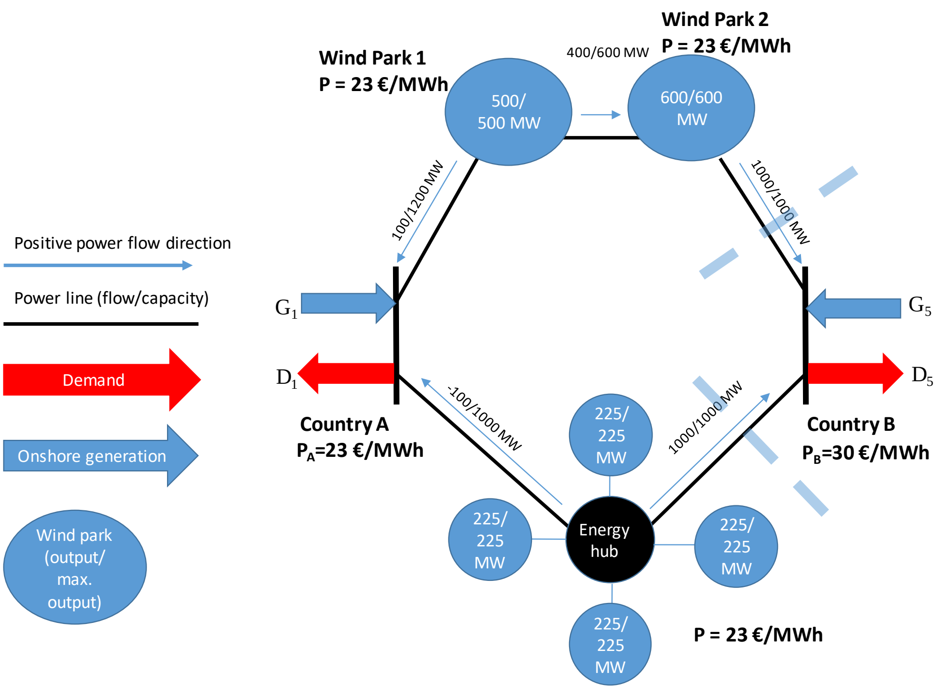

Figure 24 – Small price zones, 50% wind generation

In the low-wind case of Figure 24 – and if there is no overplanting – the zonal prices become equal to the onshore zone to which they have an unconstrained connection, i.e. Country A. This will be the most common situation. Total generation in the North price zones is 1100 MW, which is 100 MW more than can be exported to Country B. As a result, the North zone transmits 100 MW to Country A. The output of the energy hub in the South is only 900 MW, which is less than the capacity of the connection with Country B. The remaining 100 MW on this link is used for transmitting power from Country A to B. This leads to a flow of 100 MW from Country A to the energy hub.

In summary, in the small price zones market design:

- Power always flows to price zones with the same or a higher price.
- Congested cables are always fully used. There is no need for counter trading or other measures to comply with the 70% rule.
- Offshore prices reflect the marginal value of power generation and therefore provide economically optimal incentives for the operation of flexibility options such as batteries and power-to-X facilities.

The one issue with this market design is that while overplanting is economically efficient, it may depress the revenues of wind farms because of the price drop to 0 €/MWh due to curtailment. A solution to this is presented in the next section.

4.3.3 LIMITING CONGESTION RISK FOR OFFSHORE WIND FARMS

The fact that the small zones market design may lower the revenues of the OWFs in cases where there is frequent curtailment may become an issue if it leads to a higher need for financial support for wind energy. This may be politically undesirable, even if the macro-economic outcome is more efficient than without overplanting. A solution that preserves the economic efficiency of the small zones market design while offering more financial stability to the OWF operators is to provide them with Financial Transmission Rights (FTRs) between their zone and an onshore price zone.

An FTR for an OWF would provide the OWF owner with a right to sell a maximum of *x* MW at the price of Country *Y*. This would result in the OWF operators receiving the price of the onshore markets to the extent that their power was delivered there and the nodal prices for the remainder. 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. If energy storage or power-to-X facilities are present in the offshore zone, they have an incentive to consume the excess generation that would otherwise be curtailed.

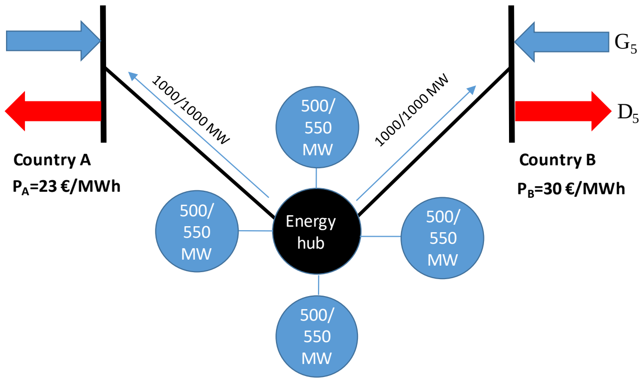

Figure 25 – FTRs for a wind hub

The FTRs can be explained with Figure 25. Each of the four wind parks connected to the offshore energy hub is given a financial transmission right for a volume of 250 MW with Country A and another one of 250 MW with Country B. The figure shows the case of maximum wind output, in which the parks need to curtail. The parks receive the zonal price of 0 €/MWh, but their FTRs provide each park with an additional 23 €/MWh * 250 MW from Country A and another 30 €/MWh * 250 MW from Country B. The remaining 50 MW of each park has no value and needs to be curtailed.

If there is less wind and the parks can only generate e.g. 300 MW each, the energy hub price is 23 €/MWh (due to congestion between the energy hub and Country B). The parks can use their FTRs with Country B to obtain the difference between the price in B, 30 €/MWh, and the hub price, for a volume of 250 MW. So, effectively, they each sell 250 MW at the price of B and 50 MW at the price of A. Thus, the FTRs not only help in times of curtailment, but always provide a way to maximise the revenues of the wind energy generators.

Traditionally, the counter party of the FTRs is the TSO. The total volume of the FTRs would need to be limited to the available network capacity. If this is the case, the TSO will always have enough revenue to pay his FTR obligations, as his FTR payments to the OWF operators are at most equal to the congestion rent that he collects. For example, in the high-wind case, the congestion rent on the cable between the energy hub and Country B is equal to (30-0) €/MWh, multiplied by the cable capacity of 1000 MW. The FTRs give the OWF owners a right to this price difference for a volume of 250 MW each, or 1000 MW total. As the FTRs provide value to the OWF operators, they should be included in the tenders of the OWFs, along with the site permits and network connections, so the OWF developers can price them into their bids.

An obstacle to FTRs may be that under current European regulation, TSOs may not be allowed to return congestion rents to electricity generators. A solution that does not include the TSO but yields the same outcome is to provide the OWF owners with 'put options' for onshore prices. So instead of providing each wind park in Figure 25 with an FTR of 250 MW for Country A and another one for Country B, the park owners could be provided with put options for these values and country. If the market operator includes the put options in the financial settlement process aftermarket clearing, the OWF owners can be paid directly from the market revenues. Then there will not be any congestion rents anymore. Taking the example of Figure 25 again, in the high-wind case the market operator would collect 23 €/MWh * 1000 MW from Country A and 30 €/MWh * 1000 MW from Country B. He would pay exactly this amount to the park owners, as the put options would provide the park owners with 30 €/MWh * 250 MW + 23 €/MWh * 250 MW + 0 €/MWh * 50 MW. So, this solution, whether implemented as FTRs or as put options, eliminates congestion rent and provides the OWF operators with the full value of their wind generation.

A great advantage of this solution is that the costs and benefits of overplanting are internalised at the OWF owner. Therefore, OWF operators can be allowed to decide themselves how much generation capacity to install. The volume of their FTRs or put options will tell them how much capacity they can always sell. Excess capacity over this FTR or put option volume may be curtailed in periods of high wind, but can also be used to produce additional wind energy in periods with less wind. At times with excess generation, the zonal price will be 0 €/MWh and the OWF operators will be indifferent to curtailing wind generation that is not covered by a contract for differences. This means curtailment will not need to be compensated and is therefore not a problem for the network operator. Even better, this zero-cost energy provides excellent incentives for power-to- X or storage facilities.

While the small price zones market design is robust for future scenarios with a MOG and power-to-X facilities, it can be implemented right away. In case of wind parks that are connected to one country, it will simply result in these parks receiving that country's price. The FTR/put option solution can be used to allow overplanting without the need for financial compensation. As soon as parks become connected to more than one country, the small zones market design will provide advantages over national price zones, as it will avoid the need for counter trading and provide efficient operational incentives to wind parks as well as power-to-X facilities.

4.3.4 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.[38] 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[39]. 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 multi-terminal and meshed grid will 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. 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.[40] The third possible option is to consider them

[38] 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.
[39] 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.
[40] 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.

as ‘offshore hybrid assets’, as defined in the Electricity Market Regulation.[41] 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 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 and some of the EU Network Codes may need to be updated. 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.[42] 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 are 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 is used with priority for guaranteeing the availability of the assets and/or for maintaining or increasing cross-zonal capacities by optimizing the use of existing interconnectors.[43] The rule that congestion income should be applied to the construction of new interconnection capacity has been scrapped.[44]

  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

[41] Ibid., recital 66.
[42] Ibid., art. 16(8).
[43] Ibid., article 19. This is the case for cross-border links. Whether it is also the case for internal transmission links depends on the national rules concerning congestion rents.
[44] Regulation 714/2009, art. 16(6).

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 (…)”.[45] From the perspective of this article, the small bidding zones model is more suitable than the other market models discussed in Section 4.3.2 as structural congestion is to be expected on hybrid assets as 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 OWFs 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 will 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 4.3.3 to offset congestion rents.
- Some parts of the EU Network Codes may need to be amended. For example, the rules on Forward Capacity Allocation are currently not written with the small bidding zones model in mind. When, as considered in section 4.5.3, FTRs are used to limit the market and price risks for OWFs located in a small price zone, the rules on FTRs in the Network Code on Forward Capacity Allocation may need to be amended. This requires further research.

4.3.5 CONCLUSIONS

A market design for a MOG that consists of price zones that are separated by congested transmission links provides for an economically efficient dispatch of wind generation, provides for economically efficient incentives for energy storage and power-to-X, maximises cross-border power flows and avoids counter-intuitive flows (from higher to lower price zones). The default solution of extending national price zones into the EEZs in the North Sea or a single offshore price zone do not meet all these criteria. Therefore, it is recommended to implement the small price zones model for offshore wind power generation.

This market design is similar to the way in which cross-border congestion is handled in Europe. The algorithm that determines the market prices could follow the same principles as EUPHEMIA[46]. It is much simpler, however, because the offshore grid will be less complex than the onshore grid and because the DC technology that will be used makes it more possible to control power flows.

A degree of over-dimensioning of OWFs, as compared to the grid capacity, is rational because it increases the utilisation rate of the network. A consequence is that network congestion would occur, which would lead to the need to curtail wind generation sometimes. However, this would be balanced by more wind generation during periods with less wind and periods when the full wind generation capacity is not available, e.g.

[45] Regulation (EU) 2019/943, art. 14.
[46] EUPHEMIA is an algorithm that calculates day-ahead prices in Europe and allocates cross-border transmission capacities

because it is still under construction or in maintenance. Minimising the total cost of the offshore wind power system requires that this trade-off is made optimally.

A disadvantage of allowing congestion is that congestion reduces the revenues of the OWF operators. Especially when wind generators need to be curtailed, the price would drop to the variable cost of wind generation and the OWFs would not have operational revenues. This would increase the need for financial support for offshore wind. It is proposed to adjust the market design in such a way that congestion rents are minimised and wind generation revenues are maximised to allow for this financial support.

There are two ways of doing this. The first is by providing the OWF operators with FTRs to an onshore market, which would effectively give them the possibility to sell their power at this onshore price, but only for a volume that can be physically transported to that market. Surplus power would need to be curtailed. A downside of FTRs is that they require the grid operator to pay the congestion rents to the wind generators, which may conflict with European regulation. A different implementation with the same effect is to provide the park operators with put options for onshore markets. Regardless of the type of implementation, this solution provides monetary value to the wind park operators. Therefore, it should be included in the package for which the park operators tender (along with the construction permit, network connection, etc.) so this value is priced into their bids.

From a legal perspective, the cables between bidding zones will need to adhere to the rules regarding 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, a study is recommended on the performance of the proposed market design in a simulation model with a realistic MOG topology. This 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 Combined Grid Solution (wind generation and market prices) can be used to simulate how this market design would have performed in that case. It is recommended that this is developed in parallel with the definition of 'offshore hybrid asset' so that policy makers have a range of well-developed options available when building the framework for multi-terminal and meshed assets.

4.4 RECOMMENDATIONS ON GOVERNMENT INVOLVEMENT

Government policy will be instrumental in delivering offshore wind capacity in the North Seas. Aside from Governments' role in determining the legal and regulatory framework for offshore wind farms, transmission assets, interconnectors and hybrid assets, Government policy will also influence the development of the supply chain and skilled personnel to work in the sector and the government can influence the planning of grid; this section focuses on these latter actions.

4.4.1 ENSURE THE QUALITY AND QUANTITY OF SKILLED PERSONNEL

Governments can 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 [14] in the UK, offers grant-funded courses to train new offshore wind technicians. This Centre is co-located with an existing college and was a 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.

4.4.2 SUPPORT THE ESTABLISHMENT OF A SUPPLY CHAIN

The development of multi-terminal grids will require the demonstration of new technologies, including those developed during the PROMOTioN project – DC Circuit Breakers, Gas Insulated Switchgear for DC-circuits and protection and control systems suitable for multi-terminal and meshed DC networks. 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 [15].

4.5 RECOMMENDATIONS ON TECHNOLOGY: TOPOLOGIES AND GRID IMPLEMENTATION

The pre-conditions necessary to ensure the multi-actor and multi-vendor aspects, shown in Figure 26, will be discussed in this section.

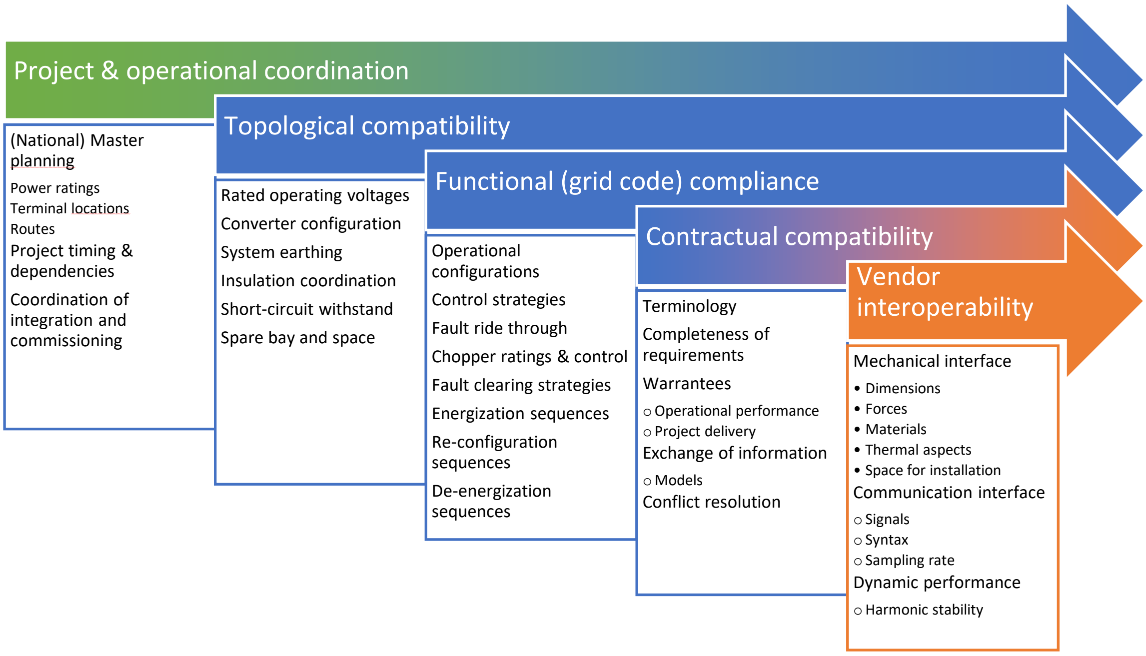

Figure 26 - HVDC project compatibility requirements

This section presents a set of recommendations that should be considered in order to successfully implement an HVDC grid. Each of them will be briefly characterised to provide a better understanding of the topic. First, some recommendations are made based on the topology generation that can be distilled from the grid development described in Section 4.1. Then, several recommendations are made based on the research conducted by the technical WPs. It includes recommendations on operation of the grid, control, stability and protection systems. In-depth analyses are summarised in in Deliverable 1.7. 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, the timing for implementation is also estimated and planned according to the topology generation.

4.5.1 PROJECT & PLANNING COORDINATION

After ensuring compatibility of applicable regulatory frameworks and market models, which were discussed in sections 4.2 and 4.3, high level characteristics of different HVDC projects such as purpose, location, capacity and timing need to be aligned to assess their potential benefit in connecting them as part of a multi-terminal extension to ensure an early identification of projects for which connecting them as part of a multi-terminal extension is beneficial.

The responsibility of coordinating/planning projects and allowing the anticipatory investments for multi-terminal extension lies with international associations such as DG Energy, ENTSO-E, ACER, national governments, national regulating authorities, TSOs and developers. Many of the aspects which need to be coordinated could/should be part of a North Sea Treaty, as described in Section 4.2.1.2, and be registered in a TYNDP-like process.

4.5.1.1 UPDATE SYSTEM OPERATION GUIDELINES

System operation guidelines are a legally binding set of minimum requirements for EU-wide transmission system operation, cross-border cooperation between transmission system operators (TSOs), using the relevant characteristics of the connected significant grid users. These guidelines are necessary for the purpose of safeguarding operational security, power supply frequency and the efficiency of the interconnected system and resources [16]. The regulation lays down mostly technical detailed guidelines and definitions on:

- requirements and principles concerning operational security;
- rules and responsibilities for the coordination and data exchange, in operational planning and in close to real-time operation;
- rules for training and certification of system operator employees;
- rules on operational security analysis, including regional operational security coordination and appointment of regional security coordinators (RSCs);
- requirements on outage coordination;
- requirements for scheduling between the control areas for which the TSOs are responsible; and
- rules aiming at the establishment of an EU-wide framework for load-frequency control and reserves.
- Operational security:

The current system operation guidelines are intended for the interconnected AC transmission network. It is very unlikely that international multi-actor HVDC networks will be realized in the absence of similar regulations to include the specifics of interconnected HVDC transmission networks. **It is strongly recommended to prioritise updating the 'Regulation (EU) 2017/1485 — guideline on electricity transmission system operation' to include HVDC specific guidelines and definitions**. Further considerations are given in section 4.2.6.

4.5.1.2 ENABLE MULTI-PURPOSE INFRASTRUCTURE USE

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

The multi-purpose use of the offshore grid for both wind export and interconnection (and onshore AC grid reinforcements) is an important driver for meshing/multi-terminal. This type of infrastructure is also commonly referred to as 'hybrid infrastructure' in for example the North Sea Energy Cooperation. **It is therefore recommended to apply multi-purpose interconnection in cases where this is optimal** i.e. when two OWFs are in close vicinity to each other. This is, for example, applicable to the NAT concept in 2030 in Figure 14, where a Belgian and UK OWF are connected to each other.

Enabling multi-purpose infrastructure is predominantly a regulatory, legal and economic challenge as discussed in sections 4.2.1.3 which discussed hybrid asset classification, and in section 4.3.1 which discusses the small bidding zones market model.

Reduction in total system cable length from one concept to another is sensitive to input assumptions. The total cable length in a system strongly influences the total CAPEX, reliability, losses, environmental impact, and amount of permitting. Depending on the assumptions, the difference can be 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 scenarios where it leads to quantifiable benefits such as a large reduction of cable length, and therefore cable costs, if aspects like protection devices play a role. This is, for example, applicable to the EUR concept in 2050 in Figure 16, where a UK, Dutch and German OWF cluster is formed, which could lead to a significant loss of infeed when a fault occurs. This means protection devices are necessary, but the reduction in cable length to connect these countries through direct point-to-point links is significant enough to justify the meshing.

The Dogger Bank seems an ideal candidate to form a backbone because of the short distances between OWFs. The optimizer used in PROMOTioN did not indicate any clear CAPEX benefits to connect all the multi-terminal topologies together to form a single grid (meaning extra-costs and complexity). However, several benefits were not expressly considered or could not be easily quantified, and it is recommended to carry out a more comprehensive and in-depth analysis on the system benefits of such a connection. Therefore, it is recommended to apply meshing only when this leads to clearly quantifiable benefits such as a decrease in cable length, an improved utilization of cable capacity, improved reliability and availability, reduced losses as described above.

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

In the topology generation, this kind of multi-purpose infrastructure is applied by 2030 in the NAT concept. While, progress is made on such multi-purpose use on the DC side in current projects, it is not yet ready for implementation due to the absence of suitable regulatory frameworks for this type of asset, unknowns about multi-actor, multi-owner HVDC grid design and integration, and challenges regarding multi-vendor interoperability. It is assumed that this will still take some time, till around 2025.

4.5.1.3 UPDATE TYNDP PROCESS TO IDENTIFY BENEFICIAL MULTI-TERMINAL GRID EXTENSIONS

To date, possible multi-terminal HVDC grid extensions have not been realized. This is often not due to the immaturity of technology, but due to the incompatibility of regulatory frameworks, project purpose and governance, project ratings and project planning. The main benefit of MOGs compared to multiple point-to-point connections is the combined use of infrastructure for different purposes, thereby increasing asset utilisation, reducing losses and improving availability. In order to be able to exploit this possibility, **coordination between different project proposals for offshore HVDC infrastructure is necessary at an early stage so that potential synergies between projects can be identified**. These project proposals should cover as a minimum:

- Purpose: Offshore HVDC infrastructure today serves several distinct purposes:
    - Interconnection (between different countries, different price zones, different synchronous areas, etc.)
    - Offshore wind export
    - AC grid reinforcement (embedded link)
    - Power from shore for offshore loads (e.g. oil & gas infrastructure)

- Even though typical TSO led project proposals for interconnectors and embedded links are (often) collected, assessed and to some extend coordinated in the TYNDP, developer or offshore wind export and power from shore projects are excluded. These should be included in order to realize multi-purpose grid integration
- Power capacities: The required power ratings of each project, and the envisaged prevailing power flow scenarios, along with the desired availability and any temporary overload or underrating characteristics should be stated. The reasoning for the sizing should be elaborated on e.g. limited by maximum loss of infeed, or due to amount of offshore load.
- Terminal locations: The onshore and offshore desired terminal geographical locations should be indicated, along with radii of optional locations within which a terminal can be placed at increased cost. Any limits on available space or building height restrictions should be stated.
- Cable and overhead line routes: As far as known at this stage, indicative cable and overhead line corridors and possible detours should be provided
- Project timing & dependencies: Necessary commissioning dates should be stated along with a justification e.g. commissioning date of an offshore wind farm or oil & gas platform.

Notification of proposals for the realisation of HVDC transmission infrastructure according to the above guidelines should be mandatory between the North Sea states in order to create visibility into project planning. The requirements and process for notification should be described in a North Sea treaty (see Section 4.2.1.2). A process similar to a network options assessment or even fully integrated with the TYNDP can be envisaged.

The proposals should be assessed on the geographical vicinity of terminals and/or cable/line routes and potential synergies when considering prevailing power flows. Second, the timing between geographically close projects should be analysed in order to determine if the temporally staged realisation of capacities would create bottlenecks or not, which would indicate the need for anticipatory investment to bring this realization forwards. Lastly, dependencies relating to the integration and commissioning of different projects should be analysed to take them into account in project planning from an early stage onwards and avoid showstoppers due to incompatible project schedules.

When project synergies are identified, a basic feasibility study should be carried out. The responsibility for carrying out this study could lie with different parties (national authority, project proposers, national TSOs, etc.), based on the involved North Sea countries' regulatory preferences. The feasibility study should clearly quantify the benefit of the synergy, provide insight into project risks, identify the high-level technical engineering parameters/aspects to be coordinated, and determine necessary anticipatory investments to enable realization of the project as an HVDC grid extension. A CBA as recommended in section 4.2.2.2 and described in PROMOTioN Deliverable 7.11 may be carried out.

The responsibility for deciding on and executing such project proposals should be indicated in the North Sea treaty, but may in principle vary by country.

Further guidelines and recommendations towards the coordinated planning of offshore wind generation and offshore grid infrastructure is given in Section 4.2.2.

4.5.1.4 ESTABLISH HUBS IN PLACES WITH HIGH WIND ENERGY GENERATION DENSITY

A prime example where the active screening of potential project synergies in order to chart the need for anticipatory investment are offshore hubs connecting several (international) wind farms. These hubs can be implemented on platforms, artificial islands, or caissons according to the specifics of the location, the amount of power generation connected to it, and the additional services which need to be realized.

Artificial islands, such as proposed by the North Sea Wind Power Hub consortium [17], can be regarded as an alternative for the steel support structures of offshore converter platforms, regardless of the topological connection of the converters. They offer several additional benefits in providing space for spare parts storage, accommodation for maintenance crew, air strip for travel by plane rather than helicopter, harbour facilities, etc.

Using high-level assumptions, the HUB concept shows that artificial islands in places where there is high wind energy generation density have the potential to significantly reduce total 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 options such as power-to-gas 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[47].

Several options for connecting the converters on the hub have been considered in PROMOTioN:

- Point-point connection: Interconnectors and wind farms are connected to shore separately through dedicated point-point HVDC links, without connections between the links on the AC or DC side. This approach is technically the most similar to status quo and least risk but offers little possibility to realize benefits by integrating multi-purpose infrastructure.
- AC hub: Interconnectors and wind farms are connected to shore by means of point-point HVDC links which are all connected at the AC side on the offshore hub. This approach allows procurement of point-point links without the need for DC grid integration, reducing risks due to perceived technology immaturity. The converter interaction in the AC offshore hub between multi-vendor converter terminals and the offshore windfarm converters remains a challenge. Opportunities for realizing benefits of multi-terminal HVDC grid use are limited, although, depending on the configuration, controllability of power flows can be better than in case of DC hubs
- DC hub: Interconnectors and wind farms are connected to shore by means of multi-terminal HVDC links which are all connected at the DC side on the offshore island. Option with potentially lowest CAPEX, footprint and losses, however DC grid integration of converters from multiple vendors is considered to be challenging

PROMOTioN did not analyse in detail the design and comparison of different hub options. **It is therefore recommended to further study potential designs of offshore hubs, including different interconnection**

[47] 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.

options for the converters, considering different support structures for different potential scenarios and the option of energy storage and flexibility on the hub. The study should consider the lifetime costs of the hub for different scenarios of offshore wind export capacity and interconnection capacity, including as a minimum the CAPEX, losses, availability, and footprint required. Realistic power flow scenarios for offshore wind generation and interconnection flows should be used.

Although the topology generation shows the applicability of the islands already by 2025, this is realistically not feasible. The regulatory and legal challenges in realizing artificial islands means they have a long lead time of around 10 years. Progress on developing islands is already underway, which means that the concept could be constructed by 2030. It will take a little while longer for these islands to become operational; potentially by 2032.

4.5.1.5 ALLOW THE APPLICATION OF ANTICIPATORY INVESTMENTS IN THE GRID

When a synergy between different projects is identified, but the project characteristics are different and incompatible, this can in some cases be remedied by means of anticipatory investments.

As an example, 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 the 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 will take several years to explore. If the design and anticipatory investment is agreed by 2025, the anticipatory investment can be completed by around 2027.

There are three main types of different anticipatory investments:

- Timing – The possibility of multi-terminal HVDC grid extension can be secured by allowing investments in infrastructure to be brought forward in time before the originally envisaged transmission need of all involved projects have materialized. A clear example is the investment needed for the realisation of an artificial island. This type of anticipatory investment does not result in a change to the technical characteristic of infrastructure, but only the delivery timing.
- Ratings – Ratings of project proposals have to be changed in order to ensure compatibility with future HVDC grid expansions. A clear example is the voltage rating of an HVDC link, which may be chosen differently when only considering the point-point connection compared to when future multi-terminal extension is taken into account. Any difference in CAPEX (and OPEX) due to such an upgrade could be seen as an anticipatory investment, even though it also led to a change to the technical characteristic of infrastructure
- Functionality – Additional functionalities such as control system upgrades, or DC switchyard components are necessary to enable future multi-terminal expansion. The provision of a spare DC bay (physical cable connection point) and the associated CAPEX and OPEX costs, are anticipatory investments.

In the early phases of evolution of multi-actor and multi-national multi-terminal HVDC grids, the acceptance and approval of anticipatory investments is of paramount importance. **PROMOTioN thus recommends National Governments and the EU to investigate the possibilities, conditions and legal frameworks for**

enabling anticipatory investments and allocate adequate funds and incentives for doing so. Regulatory solutions for allowing anticipatory investments are given in section 4.2.3.1 and possible funding options for anticipatory investments are given in Section 4.2.3.4.

4.5.2 TOPOLOGICAL COMPATIBILITY

HVDC projects can only be connected as a multi-terminal extension if several basic, technology-, vendor- and TSO independent technical requirements are met. **Short-term international collaboration and coordination on the topological technical requirements is of paramount importance** if HVDC grids developing in different locations are to be compatible with one another for future connection.

The responsibility for ensuring topological compatibility between different HVDC projects lies with international associations such as DG Energy, ENTSO-E, ACER, national governments, national regulating authorities, TSOs and developers. The aspects to be coordinated could be formalized in part of the North Sea Treaty, an offshore HVDC network code (further described in Section 4.5.3.1), multi-lateral agreements and Memorandums of Understanding. If the basic multi-terminal connections are to be established by 2025, as was described in Section 4.1.1, the topological compatibility has to be formalised before then.

4.5.2.1 STANDARDISE RATED HVDC VOLTAGES

The choice of rated voltage of any power system is primarily a compromise; higher voltages lead to reduced transmission losses but require increased insulation strength which in turn leads to higher cable cost and higher platform costs. It is primarily dictated by the maturity and cost of cable technology, which typically represents the dominant share of offshore HVDC project CAPEX. In contrast to AC, in HVDC no formally standardized HVDC voltage classes exist, and a range of different rated voltages has been applied in offshore HVDC projects to date, as shown by the different coloured lines in Figure 27. A more detailed analysis and discussion of the choice of HVDC voltage rating is given in deliverable 2.4 and [18] [19].

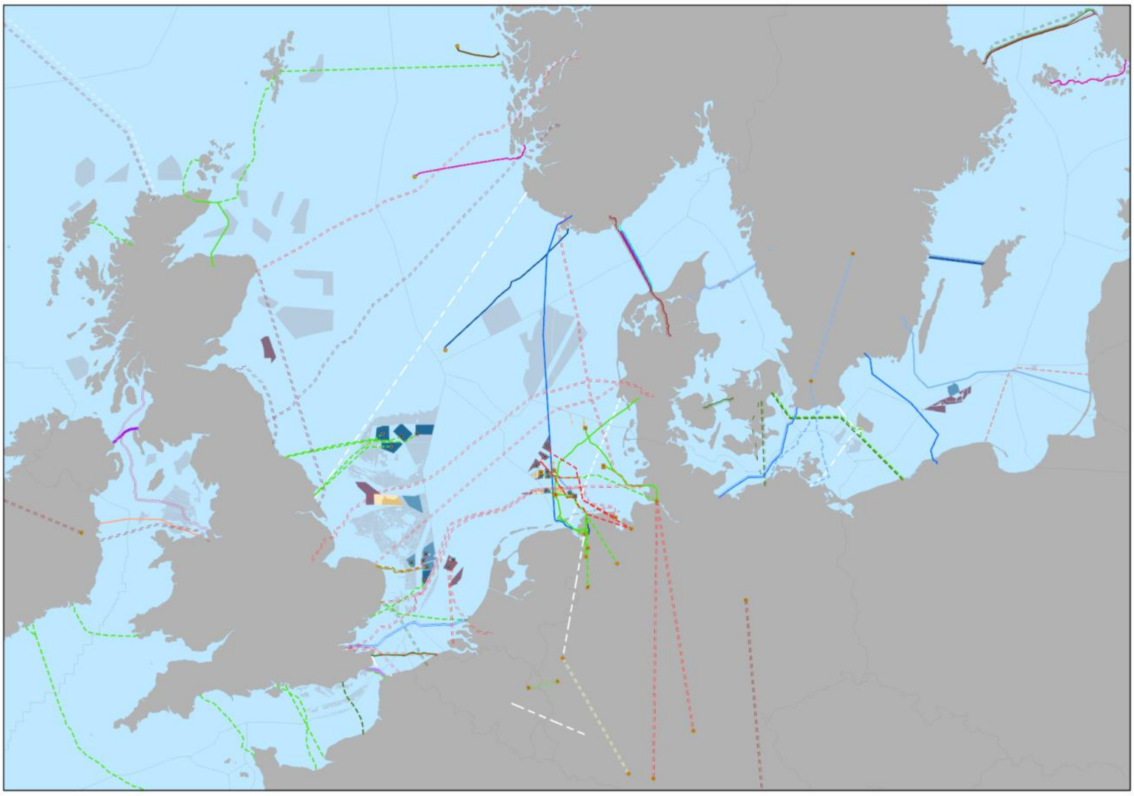

Figure 27 - Existing and planned HVDC links in Western Europe – Different colours illustrate different rated voltages (white means exact voltage unknown)

Power systems operating at different voltage levels (in steady-state and transient conditions) cannot be directly coupled to form one interconnected grid without either loss of performance (derating) of one system or additional CAPEX investments (upgrading) of the other. In the absence of cost-effective DC-DC converters, **a common rated HVDC system voltage must be agreed on (urgently)**. In PROMOTioN, a common voltage level of 320 kV has been assumed for future projects in the Irish Sea, and 525 kV for projects in the North Sea. All PROMOTioN partners agreed that these are reasonable choices. The maximum power capacities of state-of-the-art cable technology (~1.4 GW per 320 kV cable pair and ~2.6 GW per 525 kV cable pair) match with the current loss-of-infeed limits of the surrounding synchronous zones / countries. A final choice of rated voltage should be based on a comparative CBA taking into account full lifetime costs of the offshore grid.

During normal operating conditions, a voltage drop occurs across resistive components (cables) during steady-state conditions, and across inductive components (series reactors in DCCBs) during ramping operations or transient conditions. To accommodate for this voltage drop, primary equipment, most notably converters, typically have a rated continuous voltage range within which they can operate without loss of performance. Power systems with the same rated voltage, but with incompatible operating voltage ranges cannot be directly coupled into one interconnected grid without loss of performance (reduced DC current loading, reduced converter reactive power capability, reduced ramp rates) or costly CAPEX investments (additional cable). Furthermore, the multi-terminal connection of two HVDC systems increases the maximum voltage drop due to the additional cable length (and series reactors during ramping operations). **The maximum possible voltage drop occurring in a future interconnected HVDC grid, and/or measures**

and responsibility for mitigating such a voltage drop, must be coordinated already at the specification of the operating voltage range of the first contributing links. A methodology should be developed for ensuring that the addition of series reactance of for example additional HVDC circuit breakers, does not lead to a reduction of the possible real power ramp rates necessary for delivering frequency support.

During abnormal operating conditions such as faults, lightning strikes or switching events, temporary over-voltages can occur. The magnitude of these over-voltages needs to be limited to avoid damage to equipment due to limited insulation strength. Over-voltage protection devices such as surge arrestors are therefore placed at strategic locations. The insulation strength, known as Basic Insulation Level (BIL), of all components in a power system and the ratings of the overvoltage protection equipment are carefully balanced with one another in a process called insulation coordination. In HVDC, contrary to AC, the BILs are not standardized and often dependent on converter technology and vendor. Power systems with different BILs cannot be connected together without loss of performance or need for additional CAPEX investment. **It is recommended to adopt common BILs and standardize these BILs in for example IEC standards**.

Note that the above discussion applies not only to pole voltage ratings but also to **neutral bus voltages** in case of systems with dedicated metallic returns.

4.5.2.2 COORDINATE CONVERTER CONFIGURATION

Converters can be configured in monopolar and bipolar arrangements, as explained in Appendix II. Depending on the location of the system earthing point, symmetric or asymmetric configurations with respect to the pole-earth voltages can be made. From a system perspective, the main difference between monopole and bipole systems is the loss of capacity in case of a pole fault, which is 100% in case of a monopole and 50% in case of a bipole (with dedicated metallic return). While theoretically it is technically possible to connect different converter configurations together into one HVDC power system, this will complicate several aspects, like the previously discussed insulation coordination. Moreover, the behaviour under pole-to-ground faults changes due to the different earthing points leading to a change in system design for short circuit conditions. **It is recommended to coordinate the choice of converter configuration and any resulting physical ratings at an early stage of offshore grid development**.

For the deployment plan, PROMOTioN has assumed a bipolar converter configuration with dedicated metallic return in all scenarios except where point-point connections are the only sensible option. PROMOTioN recommends to agree on one configuration for systems to be interconnected, especially considering the required coordination of insulation as discussed in the previous section.

4.5.2.3 COORDINATE ANCILLARY SERVICES

Modern HVDC converters are capable of delivering a wide range of (AC and DC) ancillary services such as voltage support, frequency support, black-start functionality and active harmonic filtering. In DC systems voltage balancing and energy absorption can be added as two specific ancillary services that may also require additional hardware. The ability to deliver these functions depends, to different extents, on the DC grid performance and, especially in the case where the provision of real power is necessary, on the ability of other connected converters and associated AC systems (including offshore windfarms) to inject this real power into the DC grid sufficiently fast and in sufficient amounts. Hence the ability to deliver ancillary services requires the provision of a hardware and/or operational margin in HVDC systems capacity the size and utilisation of which should be underpinned by an appropriate cost-benefit analysis. **It is recommended to coordinate the**

need for AC and DC ancillary services, underlying market models, required technical specifications and necessary additional investments by means of a comprehensive CBA study.

4.5.2.4 COORDINATE SYSTEM EARTHING

Closely linked to the choice of converter configuration and voltage rating is the location of system earthing and choice of earthing impedance. For safety, and to provide a reference, the neutral of a power system must be earthed at one point. To prevent earth currents from flowing, no more than one earthing point should be present. Different countries may have different rules regarding the magnitude and duration of ground currents in case of emergency operation, which should be coordinated.

The choice of earthing point location determines the voltages at different nodes of the neutral of the HVDC power system, and with that the maximum steady-state pole-earth voltages experienced by the primary equipment. In case of a disconnection of a branch of the HVDC power system which contains the system earthing point, a back-up earthing location should be connected. **The location of the system earthing point, back-up locations, and the responsibility to provide earthing should be coordinated and agreed between all parties participating in offshore grid development**.

The connection to earth may include an impedance to limit the magnitude of earth fault currents. In symmetrical monopoles, different types of earthing points can be realized. The choice and size of the (equivalent) earthing impedance will affect the magnitude of any overvoltages experienced in the system during faults. This is hence closely coupled to the choice of voltage rating and BIL. **It is recommended to coordinate the type and size of the earthing impedance and the method of system earthing**.

4.5.2.5 COORDINATE SHORT-CIRCUIT WITHSTAND

Power system extensions can increase the short-circuit level at an existing point in the grid in two ways:

- Parallel paths are created reducing the impedance to the converter stations and AC grids
- Additional converter stations are placed, increasing the number of sources of fault current

Unlike AC systems, no standardized classes of short-circuit level exist to use as base when specifying short-circuit withstand and short-circuit current breaking capacities of equipment and circuit breakers in particular. Fault behaviour in HVDC systems and the operation of fault current blocking equipment is substantially different from AC grids, but **coordination on the maximum allowable short-circuit currents at specific points in the HVDC power system throughout the course of the meshed grid expansion is recommended**. It is noted that in DC grids the peak short-circuit current is typically limited by HVDC circuit breakers, full bridge converters or other fault current limiting devices.

4.5.2.6 ANTICIPATE SPARE BAY AND SPACE REQUIREMENTS

A pre-requisite for multi terminal expansion of existing (offshore) HVDC links is the existence of a physical possibility to connect an additional cable. Typically, this is referred to as an additional switchgear bay. It should be noted that the expansion from a point-to-point platform to a multi-terminal ready platform also requires additional equipment such as switchgear to disconnect and earth the additional cable, instrumentation to be able to measure the local voltage and/or current for control purposes and overvoltage protection equipment. Even though this additional equipment only needs to be placed when the extension is realised, sufficient additional space needs to be reserved at the moment of specifying the initial point-to-point link. **It is recommended to design offshore platforms with sufficient space to host the equipment necessary for the physical connection of an extension cable**. If the additional equipment is also installed immediately with the realisation of the point-to-point link, then a future extension can be made without significant downtime of the original point-to-point link.

4.5.2.7 STANDARDISE OFFSHORE HVDC PLATFORMS

Significant cost savings can be realized when standardising the design and procurement of offshore platforms and the systems contained therein. Many design aspects of the main power system will be dictated by the need for international coordination on common grid characteristics, but power capacity can be chosen by the user. It is anticipated that platform standardisation will be hard to achieve across an entire industry, but will surely have cost advantages when implemented within one transmission owner's organisation and should thus be encouraged/incentivized.

Based on the assumptions made and the current state-of-the-art cable technology capacity, the topology generation shows a significant amount of 2 GW OWFs point-to-point connected in each of the topologies[48]. It is therefore suggested to develop a standard platform design (within procurement constraints) for these point-to-point connections. It is assumed cost reductions for 2 GW 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 suggested to steer towards standardising a platform and converter design to be applied throughout the North Seas. It is recommended to determine the most adequate power and voltage ratings for such as platform based on a full lifetime CBA and consideration of technical limitations posed by the AC onshore grids of North Sea countries.

It is recommended to coordinate maritime spatial planning as this is key to reach 2 GW by "aggregating" windfarms to be connected to a single offshore AC/DC converter station. This allows the application of a standardised 2 GW concept. This recommendation is further discussed in Deliverable 12.2. 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.

2 GW of generation capacity requires around 200-400 km2 of physical wind farm size which appears realistic from the GIS study performed in Deliverable 12.2 and allows AC connections to an offshore HVDC platform. Direct AC connections from the windfarm at 66 kV carry a cost reduction according to the CBA and it is therefore recommended to apply this into the 2 GW concept (although cost advantages of using even higher array voltages such as 132 kV should not be ruled out, especially with growing wind turbine generator size). 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 [20].

4.5.3 FUNCTIONAL COMPATIBILITY

The steady-state and dynamic performance of converters, and thus of HVDC power systems, is actively controlled according to, today, mostly vendor specific control algorithms. Likewise, the protection of HVDC links today is typically integrated into the vendor specific converter control and protection system. When extending an existing HVDC link with another converter from a different vendor to form a multi-terminal, multi-purpose extension, it is imperative that the functionality of the extension is compatible with that of the existing

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

link. It is important to consider the required control and protection modes for a future multi-terminal grid at the outset of specifying individual links which could be connected in future, to avoid unnecessary control system replacement, or hardware adjustments.

4.5.3.1 ESTABLISH AN OFFSHORE HVDC NETWORK CODE

To facilitate the interconnection of multiple HVDC systems to one multi-terminal systems, a set of functional specifications has to be derived, which ensures the compatibility and interoperability of the different components and especially the converters in a DC grid. Such functional specifications are typically set in grid codes. However, existing Grid Codes for HVDC systems specify requirements at the AC point of connection, but have not yet targeted the DC point of connection. In a first step, DC systems were seen as addition to the existing AC transmission grid and the prevailing of single point-to-point links did not yet require corresponding requirements at the DC point of connection.

As discussed in this report, there are several options for designing, operating and protecting future HVDC grids. It is therefore challenging to define a set of exhaustive requirements at the DC point of connection, especially taking into account the need to be technology neutral and to allow for future innovation of the rapidly evolving HVDC technology. It is noted that very valuable work has been done in CIGRE Technical brochure 657: '*Guidelines for the preparation of "connection agreements" or "grid codes" for multi-terminal schemes and DC grids'*, and in CENELEC's '*Technical Specification CLC/TS 50654-1: HVDC Grid Systems and connected Converter Stations'* in providing terminology, a list of functionalities required and or possible for HVDC systems and corresponding parameter lists and guidelines. It is recommended to apply these guidelines and technical specifications and improve the current versions with return of experience.

Based on the analysis of design and control of an offshore grid, existing grid codes and standardisation documents were reviewed to provide recommendations for the next steps towards HVDC grid codes also with respect to the specifications at the DC point of connection and the integrated system behaviour. 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 network code. General aspects that should be specified either in an HVDC grid code or be taken into account when writing an HVDC grid code from a system design perspective are

- DC voltage levels and ranges
- Overall system control and operation
- HVDC Converter Control Modes and specifications
    - DC voltage control | Power control | Droop Controls | Grid-forming Controls
    - Ramp Rates
    - Dynamic behaviour
    - DC Fault Ride Through (FRT)
- Offshore Wind Farm Controls
    - Control Modes
    - Dynamic behaviour
    - FRT Profiles (considering both AC and DC faults)
- Ancillary Services

- Sequences
    - Energization | Re-configuration | Restoration | De-energization

With regard to the technical specification, there are several aspects that need to be further investigated before a detailed HVDC grid code can become reality: There are several functionalities an HVDC converter could fulfil, however, especially with regard to all functionalities requiring real power exchange, the overall system perspective has to be taken into account. Moreover, there is not yet a suitable way to specify the controls of HVDC converters in a way, such that detrimental control interactions can be avoided from the design phase.

It is recommended to start work on developing and adopting a legally binding DC system network code as soon as possible. Ideally there would be one set of specifications at the DC point of connection in an HVDC grid code, that is applicable regardless of the country to facilitate the coordinated development of a multi-national offshore grid. Working out the details and agreeing on the characteristics takes time but can be done quickly if sufficient organizational and political support is realized.

4.5.3.2 ENSURE STABLE OPERATION AND CONTROL

The operation of (meshed) offshore HVDC grids and any connected offshore AC grids is governed by the characteristics of the converter and the offshore wind turbine and wind farm control systems. The overall operation therefore needs a central grid control which defines the power flow by setting the control modes, limits, ramp rates and corresponding set points - otherwise the HVDC system will not operate. These control modes and set points, e.g. power or droop values will not be hardcoded into the converters, which would lead to the loss of control flexibility. This would require corresponding communication of measurement signals and modes between a central controller and the converters.

For existing point-to-point systems connecting OWF to shore, this adaptive setting might only be regularly changed for the AC side reactive power set points in normal operation. However, even for point-to-point systems embedded into the AC onshore grid, a “central” control on the system for the DC side power flow is needed. Currently, the links are or will be controlled by the existing AC system control rooms.

The operational routines and set points for a DC grid are different from an AC grid, so for the HVDC grid new functions in the “central grid controller” are needed:

1. Setting of control modes and set points for normal operation –based on the availability of the installed grid components and different objectives (e.g. lowest losses in the DC or combined AC/DC system)
2. Setting of controls for infeed changes, e.g. due to wind fluctuations or OWF shut down
3. Setting of controls for emergency operation – e.g. certain fault clearing strategies need a central controller in the DC system to work, e.g. a full-bridge multi-modular converter (MMC) based fault clearing strategy
4. Setting of controls for ancillary services on the AC side, e.g. frequency support, or for ancillary services on the DC side, e.g. DC side reserves

Furthermore, the central grid control must be able to energize, re-configure and de-energize the offshore power system and parts thereof in pre-defined switching and operational sequences which are compatible with the overall system control. **It is recommended to initiate work on analysing, specifying, designing and demonstrating central grid control, as well as on methods to test it and frameworks for its**

governance. It is recommended to ensure the central grid control can be implemented in a distributed way as much as possible to avoid single-vendor solutions. It is recommended to investigate open-source options for the upper level control layers of HVDC converters to ensure interoperability whilst guaranteeing earning models for the vendors.

While designing the onshore AC interface of the MOG, active power control and frequency support requirements must be fulfilled to comply with the relevant HVDC grid code. This means that the offshore AC grid has to operate within certain frequency ranges and has to be capable of withstanding a certain rate of change of frequency. Detailed values of frequency ranges and reactive power support can be found in Appendix II. This Appendix also presents recommendations about control, fault ride-through capability, information exchange, protection devices, and settings requirements.

The offshore generation of a MOG also has a range of constraints that has to be satisfied. 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 Appendix II. Besides, a wind generator is required to withstand faults; hence has to control and meet robust requirements during these faults. Furthermore, the wind turbine generator has to be able to fulfil stability, robustness and voltage requirements. Apart from this, during energisation of the generators the offshore grid has to withstand start-up requirements. Detailed data for all of the mentioned needs are listed in Appendix II.

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

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, reconfiguring 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 II.

4.5.3.3 CHOOSE AND IMPLEMENT AN APPROPRIATE PROTECTION SYSTEM

Protection systems are needed in case of a fault to protect end users from harm, damage to power system equipment and to prevent disruption of the operation of the power system. The extent to which a protection system is developed depends on the risk associated with faults (probability and impact) and the costs associated with protecting the system. Protection of a DC transmission system is substantially different from protection of an AC transmission system. This is for three main reasons:

- DC current faults do not undergo regular zero-crossing[49], in contrast to AC faults. Their interruption is therefore more challenging and requires novel technologies such as HVDC circuit breakers and/or full-bridge converters.
- DC faults cause very fast rise of fault currents and must be cleared much quicker than AC faults since power electronic based devices (converters, hybrid breakers) have a limited overload capability. It is shown that to achieve stable and safe operation, faults must be detected, located and

[49] 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.

cleared in several milliseconds, as opposed to several tens to hundreds of milliseconds in AC applications.

- HVDC equipment, and in particular the converter power electronics, has a very limited overload capability, making them sensitive to overloads and placing stringent constraints to the power system protection system.

Several protection strategies have been under evaluation in PROMOTioN. Different fault clearing strategies are characterised by the type and number of HVDC circuit breakers, the locations of HVDC circuit breakers and the type of converters. They are typically classed as fully selective, partially selective, and non-selective fault clearing strategies, based on the size of the smallest part of the grid that contains the fault that is de-energized to clear the fault. After the fault has been cleared, operation has to be restored by re-dispatching the remaining converters. The detection of a fault, the logic that determines which breakers to open (or what converters to block), how to restore operation in the healthy part of the system, and the necessary communication hardware is typically implemented on a programmable digital signal processor also known as an intelligent electronic device (IED). The protection system is likely to interact with the system control and the converter control systems, in particular to ensure smooth system restoration. The operation of protection devices such as HVDC circuit breakers may have an effect on converter operation. Hence, the DC grid protection design should be coordinated such that the fault clearing strategy, protection equipment, converter technology, controls and rating are matched. Future DC grid codes should accommodate this through the definition of clear specifications and as such enable multi-vendor interoperability. The partially and non-selective protection strategies require substantially lower investments compared to the fully selective DC protection. However, these solutions, may require substantial compensation (reserves requirement) in the onshore grid to compensate for the sudden (temporary) loss of significant power infeed into the onshore grid.

The choice of fault clearing strategy is hence dictated by the connected AC systems' strength, the cost of the protection system components, and the operational cost such as increased losses, costs of contracting additional frequency reserves and additional maintenance. **It is recommended to determine common and, where possible, technology neutral functional specifications for converter control and protection equipment in order to achieve coordination between different protection zones with different fault clearing strategies.**

More detailed specifications and recommendations for each protection system strategy requirements can be found in Appendix II of this document. The protection strategies are to a large extent interoperable and can be specifically chosen for a particular part of the grid according to PROMOTioN analysis. Following this, it is also found that it may be beneficial to be able to split the grid into different sections. There are relatively few lock-in or interoperability issues expected from a difference in protection strategy by different grid operators. However, when no single protection strategy is chosen, it is not possible to define a common DC fault ride through (FRT) requirement in a grid code that is intended to govern all offshore HVDC system to be interconnected due to varying requirements based on the chosen protection strategy. PROMOTioN research has shown that the choice for HVDC grid fault clearance strategy is based on local characteristics of connected AC grids, and that HVDC grids with different fault clearance strategies can in principle be connected in future. Hence there is no right or wrong way to do it, but it is recommended to start applying real HVDC grid protection as soon as possible to gain practical experience, rather than waiting for an optimal solution to be developed.

4.5.4 VENDOR INTEROPERABILITY

Cost reduction and the underlying innovation is realized in part through non-discriminatory competitive tendering practises. It is hence of utmost importance that similar HVDC transmission systems with identical functional specifications from different vendors can be combined into one system without loss of performance. Doing so will avoid vendor lock-in, lead to higher system resilience (lower chance of systematic failure), open up increased production capacity, and ensure distributed liability in case of non-compliance issues. Vendor operability is crucial already for the first elements of the offshore grid, as these may evolve into multi-terminal or meshed systems. **It is therefore recommended to start the preparation for this as soon as possible and have the recommendations below implemented by 2025.** Involved parties are ENTSO-E, the TSOs and other grid developers and HVDC equipment vendors.

4.5.4.1 DEVELOP MODELS AND METHODS TO ENSURE DYNAMIC PERFORMANCE OF MULTI-VENDOR HVDC SYSTEMS

Different implementations of digital control systems with the same function specifications may in some cases lead to unstable behaviour or a loss of performance when they are connected in the same HVDC transmission system. Identifying and solving or mitigating interactions between the control systems due to resonances in and with the system at an early stage is in most cases the most cost-effective way. This can be done through a series of analysis starting with offline simulations using the black-box models supplied by vendors and finally validating this by means of hardware-in-the-loop simulations with the actual control & protection replicas of both vendors' systems. In carrying out these studies it is important to take the following aspects into account:

- Fidelity of black-box models – What control & protection system functions and aspects are included in the model and with what steady-state and dynamic accuracy have they been modelled? What output signals does the model provide, and what parameters are made available to change? During what phase of the HVDC transmission system development are the models made available? Are the models automatically upgraded with real control system updates? The provision, fidelity, flexibility, delivery and maintenance of the models must be coordinated and as much as possible standardized.
- Validation of black-box models - Results of grid studies are only as good as the quality of the model. Validation by means of hardware-in-the-loop simulations is thus of key importance. This can be done at the vendors' facilities during dynamic performance testing, or in an independent laboratory. In any validation work, it is imperative that the Intellectual Property (IP) rights of the vendor are respected and protected.
- Comprehensiveness of scenarios – The dynamic performance and compliance with the functional specifications (grid code) of the multi-vendor system must be validated for all conceivable permitted operational configurations, operating points, grid events (e.g. voltage sags, faults, sudden set-point changes).

It is recommended to standardize the methods for qualifying dynamic performance of multi-vendor HVDC transmission systems.

4.5.4.2 STANDARDIZE COMMUNICATION INTERFACES

Today, most HVDC converter & equipment vendors use their own in-house developed digital communication systems. These are not typically compatible with one another. The ability of different elements in an HVDC transmission system to communicate i.e. to exchange data and to use the exchanged data, is a pre-requisite for the development of an offshore grid. **It is recommended to fully standardize the communication interfaces between equipment of different vendors**. Apart from functional requirements, the standardisation should as a minimum consider:

- Which signals must be made available as a minimum?
- What syntax and semantics should the signals be expressed in?
- What sampling rate must be provided for different signals?

4.5.4.3 STANDARDIZE MECHANICAL INTERFACES

It is recommended to develop standardized interfaces for primary and secondary equipment of different vendors. These standards should include requirements for at least the following aspects: Dimensions, Forces, Materials, Thermal aspects, Required space for installation. The standards should include procedures for how compliance with the requirements should be qualified and demonstrated.

4.5.5 CONTRACTUAL COMPATIBILITY

Different TSOs and developers procure HVDC transmission systems in different ways, often reflecting the risk appetite, in-house experience and financing structures they have. Traditionally, point-to-point HVDC transmission systems have been procured from EPC (Engineering, Procurement and Construction) contractors in which the scope of supply may have been divided into a high-level granularity of both converters (hardware and complete control & protection) and line/cable. The functional requirements of the HVDC link were mostly specified at the AC interfaces of the converters where grid codes would apply, and performance warrantees regarding project delivery and operational aspects such as losses and availability were agreed. The paradigm change to organic step-wise HVDC grid development requires a different approach towards the procurement of HVDC transmission systems and a much greater role for the purchaser (TSO or developer). **It is recommended to develop a best practise guideline which can be followed to ensure that procurement choices do not exclude future expansion of HVDC transmission systems**. The following aspects, among others, should be considered:

- Terminology & definitions – Different vendors sometimes use different (often product branding) terminology for the same components or functions. This may be confusing or misleading in multi-vendor settings and it is recommended to update existing standard terms and definitions to include multi-terminal HVDC grid aspects a good basis is the technical specification developed by CENELEC 50654 [4].

- Procurement strategy – The development of an HVDC transmission systems consists of different main hardware elements and different development phases which could be supplied by different vendors in an effort to get a more competitive tendering. An increasing number of interfaces will lead to increased risk and an increased effort required from the TSO to manage this. It is recommended to ensure that the choice of procurement strategy in one project does not lead to undue or excessive risk management effort for a future extension of that grid.

- System integration responsibility – A procurement strategy should clearly indicate which party is responsible for the system integration. The allocation of this role should not lead to contractual barriers in the context of stepwise offshore grid development. It is thus recommended to study different possibilities and their pros and cons as a guideline for purchasers of HVDC equipment.
- Completeness of requirements – In specifying grid extensions, it is important to have a common understanding of the level of detail, nature and number of requirements to ensure that a balance is struck between what is necessary to enable grid extension, but leave sufficient room for innovation and cost reduction. The CENELEC technical specification could for example be used as a reference.
- Exchange of information – The exchange of information between vendors which is required to enable the successful operation of their equipment in one HVDC transmission system must be enabled and thus formally determined in the contract. **It is recommended to develop a guideline or even standard for the parameters, models, interface definitions, and other information which needs to be exchanged as a minimum, the timing of the exchange and the method of exchange**. This is especially relevant for aspects which have not yet been standardized.
- Warrantees, liabilities and conflict resolution – Typically manufacturers give warrantees on performance (e.g. losses and availability) and project delivery which are contractually linked to fines and sometimes bonuses if these warrantees are broken or met, respectively. The extension of existing infrastructure could affect the contractual requirement of one manufacturer to satisfy these warrantees outside his control. To avoid undue penalties or bonuses, **it is recommended to take grid extension into account in the formulation of the warrantees in the procurement phase**. Similarly, **clear guidelines should ideally be established on how liability in case of a multi-vendor system should be established and what type of measurements and logs should be kept in order to do so**. For any cases that fall outside these guidelines, **it is recommended to develop and commonly adopt conflict resolution models**.
- Technology qualification, testing & facilities – In a multi-vendor and multi-actor system, the performance of the whole system, and thus the benefit to a user of the system, relies on the performance and quality of individual parts of it. To ensure a minimum level of performance, all technology used in the system should be qualified to a minimum standard agreed between all users of the system. This applies to the level of QA/QC applied during fabrication, the tests done to prove technology meets the requirements, and the type of facilities these tests should be carried out in (capability to recreate suitable physical and functional stresses, and independence are aspects to consider). **It is recommended to agree on a common set of technical standards for use in the development of the HVDC grid, to carry out a gap analysis on the scope of currently existing standardisation and to initiate technical standardisation activities in missing disciplines**.

4.5.6 FURTHER RESEARCH, DEVELOPMENT & DEMONSTRATION

The PROMOTioN consortium is of the opinion that from a technical perspective there are no fundamental showstoppers towards the development of meshed multi-terminal offshore HVDC grids. However, several fields of further research have been identified that may lead to more cost-effective, environmentally friendly, optimally integrated and increased functionality development and usage of the meshed offshore HVDC grid.

4.5.6.1 INITIATE FULL-SCALE MULTI-VENDOR, MULTI-PURPOSE, MULTI-TERMINAL HVDC NETWORK PILOT

Individual technology elements have been demonstrated to have achieved sufficient maturity for deployment in real HVDC grids. The integration of these technology components into one functioning system has only been shown by demonstration, and even though there is no doubt that it is technically possible, many issues with regard to multi-vendor implementation have yet to be addressed. To achieve this and instil confidence in the technology, **the PROMOTioN consortium recommends the development of a full-scale pilot, which, procured on a commercial basis through competitive tendering, not only demonstrates the technology maturity but also realizes the potential benefit of multi-vendor, multi-purpose multi-terminal HVDC network solutions, compared to their point-point counterfactual case**. PROMOTioN has identified and analysed several potential sites in north-west Europe that could be suitable for such a pilot. The analysis has been further described under the short-term projects section in Chapter 3.

4.5.6.2 EXPLORE THE NEED FOR FLEXIBILITY IN THE SYSTEM

The availability of flexibility options, in particular energy storage, at the onshore hosting points has a strong effect on the ability to realize offshore grid integration synergies. Increasing onshore hosting capacity significantly reduces the total cable length required for all concepts but is more beneficial for the NAT, EUR and HUB concepts. Additionally, in the benefit analysis of 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 due to onshore grid congestion or low demand. For these reasons it 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. **It is recommended to carry out an integrated offshore grid planning study, taking into account onshore AC grid constraints and options for flexibility.**

4.5.6.3 PERFORM INTEGRATED AC/DC SYSTEM STUDIES

The PROMOTioN physical scope has been conveniently limited to the onshore landing points of the offshore HVDC grid. It is however clear that the integration of large amounts of power delivered by the offshore HVDC grid into the existing onshore AC grid is a formidable challenge, and will have strong influence on the topology and functionality of the offshore HVDC grid. The ability of AC grids to host the HVDC connections points is limited due to capacity constraints, constraints due to changing technology, constraints due to changing behaviour and roles of grid users. System integration, in the widest sense of the word, considering the path from generator to consumer, is they key aspect. Whereas EU projects such as PROMOTioN and BestPaths have delivered technical and regulatory solutions for HVDC grids, and MIGRATE and GARPUR have focused on the evolution of AC grids, **it is highly recommended to initiate research and development considering the system integration of large-scale pan-European HVDC grids into the incumbent but rapidly changing AC grids**.

New **tools and modelling approaches** for representation of large HVDC systems and integrated system studies need to be developed. Currently, time domain grid integration studies of HVDC systems can take many hours to run per scenario, many scenarios need to be considered, and the results are evaluated by hand to determine if operation is for example grid code compliant. The sheer amount of processing time required makes it almost impossible to do so for a large integrated grid. New simulation approaches, automated evaluation, and new modelling techniques should be developed in order to study the **interaction** between AC and DC systems for different time frames and contingencies and thereby facilitate the integration of large HVDC grids into existing AC grids.

Successful operation of integrated HVDC and AC grids will require the development of **control and communication concepts** for integrated system operation. The real-time dispatch of variable renewable energy sources, storage and ancillary services should be integrated vertically through the different layers of European and national transmission as well as distribution, taking into account the ability of both consumers, variable energy sources and storage options in different levels of the power system to contribute to system stability. In addition, the coordination should be integrated horizontally between different countries and users of the power system, fully making use of the possibilities offered by automated digital control systems. Next to developing the technical solutions, research should be initiated regarding the governance and regulation of the integrated power system operation i.e. which party owns and operates the different power system operation aspects and what market models can offer appropriate risk-reward balance.

4.5.6.4 CARRY OUT RESEARCH INTO OFFSHORE WIND FARM ADVANCED CAPABILITIES

Offshore wind farms are envisaged to take up a significant share of the future generation mix and thereby replace conventional generation. PROMOTioN has shown that the ancillary services of conventional power plants such as reactive power support, power oscillation damping, frequency support and black start operation can in principle also be delivered by HVDC connected offshore wind farms. To realize these abilities will require modifications to turbine and converter control systems, auxiliary power supply arrangements and the system control and communication systems. **It is recommended to carry out further research, development and demonstration work on how to realize, qualify and further enhance offshore wind farm ancillary service technologies, and crucially, how to integrate them into the offshore HVDC grid and the wider AC/DC power system.**

4.5.6.5 ANALYSE THE HVDC HUB TOPOLOGY

PROMOTioN did not study different types of HVDC hub implementations and their pros and cons in great detail. When implementing hubs, different designs (e.g. different numbers of and type of busbars, and the number and connection of HVDC circuit breakers) can be adopted that have different impacts on the level of redundancy and selectivity of fault clearing. **It is recommended to carry out a full lifecycle costs and benefits analysis to determine the applicability of AC vs DC hubs in different scenarios**. Furthermore, **it is recommended to establish technical design considerations for DC hubs**, especially in the light of power system redundancy requirements and protection.

4.5.6.6 CONTINUE DC SWITCHGEAR DEVELOPMENT

Further development of HVDC switchgear is foreseen to be necessary in order to improve reliability, improve operation, reduce environmental impact and reduce costs.

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, demonstrating their long-term viability whilst offering solutions for the often vendor-specific operation and maintenance aspects of these different alternative gases**. In addition, several key components which are necessary for offshore HVDC grid development such as high-speed switches and pre-insertion resistors do not currently exist as gas insulated components. Similarly, test requirements and procedures for these components need to be developed and standardised. 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 a commercial application at 320 kV and a full scale pilot at 525 kV.

With regard to HVDC circuit breakers, several prototypes have been developed and PROMOTioN has demonstrated that the technology is in principle ready for application. However, due to the use air insulated components in many HVDC circuit breaker technologies, and due to the sheer number of components required, they are typically rather large devices and require a substantial footprint. Offshore, this footprint comes at a significant cost which hampers the uptake of these devices. **It is recommended to carry out further research on HVDC circuit breaker topologies with the aim of reducing their cost and footprint.** Potential avenues are the use of gas insulated components, novel types of valves, improving speed of operation, etc.

4.5.6.7 FOCUS EFFORT ON INTEROPERABILITY OF CONTROLS AND PROTECTION

Interoperability between control and protection systems, particularly when supplied by different vendors, is seen as a significant hurdle towards HVDC grid development. As discussed in section 4.5.2, this concerns pre-dominantly the communication interfaces, but also mechanical and electrical interfaces and dynamic performance. **It is recommended to focus significant effort onto standardisation activities that address these issues and carry out further research on control & protection strategies that are less prone to issues due to different vendor implementations**. Examples of such approaches are the open-source implementation (and licencing) of control & protection layers of converters that have an impact on the system behaviour (i.e. upper level controls).

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

A major obstacle to realizing synergies in transmission needs using HVDC grids is the absence, low technology maturity and potential cost of DC-DC transformers. Currently, a DC-DC conversion would need to be done using a back-back DC-AC-DC conversion, similar to frequency converters between different synchronous AC zones. This makes it impossible or costly to connect HVDC grids with different voltage levels and optimize those for a class of power ratings and transmission distances. Furthermore, DC-DC conversion may be a necessity in more complex meshed HVDC grids to control power flows.

Research, development and demonstration into cost-effective options for HVDC to HVDC conversion is thus essential. 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.

5 STAKEHOLDER ACTIONS FOR THE DEVELOPMENT OF A MESHED OFFSHORE GRID

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 industrial and marine environments and commercialised. There has been extensive research into the legal and regulatory frameworks that exist and how these may need to change to allow for multi-terminal multi-jurisdiction and multi-purpose offshore networks. This chapter focuses on the stakeholders who need to be involved in translating the recommendations made in PROMOTioN into action. The PROMOTioN team has already had an impact in amending the legal framework for offshore transmission – WP7 identified the potential 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 Energy Package.

This Chapter takes the recommendations made in Chapter 4 and allocates them to different stakeholders. These stakeholders may be directly or indirectly involved in carrying out the recommendation, either through directly being the implementation responsible party or the end-user or indirectly through being of influence on the development of the implementation of the recommendation. An assessment is also made whether preparations for each of the recommendations has not been started, has been started but is ongoing or has been started and finalised.

Key stakeholders that participate in the main stages of the development of an HVDC offshore grid are described in Appendix IV.

5.2 EUROPEAN COMMISSION'S DIRECTORATE-GENERAL ENERGY

The objective of Directorate-General (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. DG Energy, as part of the EC, is responsible for any recommendations that should be implemented on a European level.

5.2.1 DIRECT RECOMMENDATIONS

5.2.1.1 CREATE A ROBUST LEGAL DEFINITION OF OFFSHORE HYBRID ASSETS

Initially, 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. This will provide greater certainty for projects between EU countries, particularly if the small bidding zones market model is not widely implemented. Over time, these provisions should be developed, and incorporated into a mixed partial agreement setting out the process for cooperation and decision making amongst north seas countries, including those outside the EU. This will include a common interpretation of relevant UNCLOS provisions, alongside the aims, and principles of the MOG. In addition, the mixed partial agreement will set out the position agreed between north seas countries on:

- 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

Moreover, to keep the legal framework up to date, a panel of experts should regularly assess developments in HVDC and wider energy system technologies and recommend amendment to the legal framework to ensure it remains fit for purpose.

5.2.1.2 ENABLE ALTERNATIVE FUNDING STRUCTURES AND FINANCIAL INSTRUMENTS TO ENSURE SUFFICIENT INVESTMENT CAN BE ACCESSED

In the near term, support schemes for OWF will continue to be necessary to support the sector. Therefore, to encourage cooperation, 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 4.3, 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.

5.2.1.3 PROJECT & PLANNING COORDINATION

The responsibility of coordinating/planning projects and allowing the anticipatory investments for multi-terminal extension lies with international associations such as DG Energy. Therefore, DG energy will be directly involved in the recommendations listed under project & planning coordination, together with ENTSO-E, ACER, national governments, national regulatory authorities and TSOs and developers. This means DG Energy is recommended to work together with these stakeholders to:

- Update system operation guidelines to include HVDC grid characteristics
- Initiate development of HVDC grid code
- Enable multi-purpose infrastructure use
- Update TYNDP process to identify beneficial multi-terminal grid extensions
- Establish hubs in places with high wind energy generation density
- Allow the application of anticipatory investments in the grid

5.2.1.4 TOPOLOGICAL COMPATIBILITY

Next to this, the DG Energy is responsible for implementation of the topological compatibility recommendations. These have the same actors as those mentioned under Project & planning coordination. This means DG Energy is recommended to work together with the same stakeholders to:

- Standardise rated HVDC voltages
- Coordinate converter configuration
- Coordinate ancillary services

- Coordinate system earthing
- Anticipate spare bay and space for future connections
- Standardise offshore HVDC platforms

5.2.1.5 FURTHER RESEARCH, DEVELOPMENT & DEMONSTRATION

In all areas where more research work needs to be done, DG Energy can facilitate the necessary funds and requirements for research, similarly as was done with PROMOTioN. DG Energy can supply the other stakeholders, like ENTSO-E, TSOs and developers and manufacturers with the correct incentives to:

- Initiate full-scale multi-vendor, multi-purpose, multi-terminal HVDC network pilot
- Explore the need for flexibility in the system
- Perform integrated AC/DC system studies
- Carry out research into offshore wind farm advanced capabilities
- Analyse the HVDC hub topology
- Continue DC switchgear development
- Focus effort on Interoperability of controls and protection
- Research the need for DC/DC converters in the system

5.3 ENTSO-E

5.3.1 DIRECT RECOMMENDATIONS

5.3.1.1 VENDOR INTEROPERABILITY

Interoperability of the offshore grid components will require substantial regulation that compels manufacturers to produce their components to specific standards, or ranges of standards. Although the development will be in close cooperation with manufacturers and TSOs, it will be the EC that will need to implement this regulation.

5.3.1.2 PROJECT & PLANNING COORDINATION

The responsibility of coordinating/planning projects and allowing the anticipatory investments for multi-terminal extension lies with international associations such as ENTSO-E. Therefore, ENTSO-E will be directly involved in the recommendations listed under project & planning coordination, together with DG-Energy, ACER, national governments, national regulatory authorities and TSOs and developers. This means ENTSO-E is recommended to work together with these stakeholders to:

- Update system operation guidelines
- Enable multi-purpose infrastructure use
- Update TYNDP process to identify beneficial multi-terminal grid extensions
- Establish hubs in places with high wind energy generation density
- Allow the application of anticipatory investments in the grid

5.3.1.3 TOPOLOGICAL COMPATIBILITY

Next to this, the ENTSO-E is responsible for implementation of the topological compatibility recommendations. These have the same actors as those mentioned under Project & planning coordination. This means ENTSO-E is recommended to work together with the same stakeholders to:

- Standardise rated HVDC voltages
- Coordinate converter configuration

- Coordinate ancillary services
- Coordinate system earthing
- Anticipate spare bay and space
- Standardise offshore HVDC platforms

5.3.1.4 ESTABLISH AN OFFSHORE HVDC NETWORK CODE

Network codes are established and implemented by ENTSO-E, to which the offshore HVDC grid code should be no exception. Currently no HVDC network code exists for the DC system, and this should be developed as a matter of urgency. Although ENTSO-E is the party responsible for implementation, it is also crucial that ACER, TSOs and developers, NRAs, manufacturers and standardisation bodies are part of the implementation process in order to guide ENTSO-E in the drafting of the Network Code.

5.3.1.5 VENDOR INTEROPERABILITY

ENTSO-E is one of the responsible parties to ensure vendor interoperability. Together with TSOs and developers and with the help of manufactures and OWF developers, ENTSO-E is recommended to:

- Develop Models and methods to ensure dynamic performance of multi-vendor HVDC systems
- Standardize communication interfaces
- Standardize mechanical interfaces

5.3.1.6 CONTRACTUAL COMPATIBILITY

ENTSO-E is one of the responsible parties to ensure contractual interoperability. Together with NRAs and TSOs and developers and with the help of manufactures, it is recommended that ENTSO-E develops guidelines for the procurement of HVDC systems to ensure contractual compatibility.

5.3.1.7 FURTHER RESEARCH, DEVELOPMENT & DEMONSTRATION

In all areas where more research work needs to be done, ENTSO-E can facilitate the research and take on research areas that are of interest of ENTSO-E. ENTSO-E can use the incentives supplied by DG Energy to cooperate with the other stakeholders, i.e. TSOs and developers and manufacturers, to:

- Initiate full-scale multi-vendor, multi-purpose, multi-terminal HVDC network pilot
- Explore the need for flexibility in the system
- Perform integrated AC/DC system studies
- Carry out research into offshore wind farm advanced capabilities
- Analyse the HVDC hub topology
- Continue DC switchgear development
- Focus effort on Interoperability of controls and protection
- Research the need for DC/DC converters in the system

5.4 SUPRANATIONAL REGULATORY AUTHORITIES - ACER

5.4.1 INDIRECT RECOMMENDATIONS

5.4.1.1 PROJECT & PLANNING COORDINATION

The responsibility of coordinating/planning projects and allowing the anticipatory investments for multi-terminal extension lies with international associations such as ACER. Therefore, ACER will be directly involved in the recommendations listed under project & planning coordination, together with DG-Energy, ENTSO-E, ACER, national governments, national regulatory authorities and TSOs and developers. This means ACER is recommended to work together with these stakeholders to:

- Update system operation guidelines
- Enable multi-purpose infrastructure use
- Update TYNDP process to identify beneficial multi-terminal grid extensions
- Establish hubs in places with high wind energy generation density
- Allow the application of anticipatory investments in the grid

5.4.1.2 TOPOLOGICAL COMPATIBILITY

Next to this, the ACER is responsible for implementation of the topological compatibility recommendations. These have the same actors as those mentioned under Project & planning coordination. This means ACER is recommended to work together with the same stakeholders to:

- Standardise rated HVDC voltages
- Coordinate converter configuration
- Coordinate ancillary services
- Coordinate system earthing
- Anticipate spare bay and space
- Standardise offshore HVDC platforms

5.4.1.3 ESTABLISH AN OFFSHORE HVDC NETWORK CODE

Although ENTSO-E is the party responsible for implementation, it is also crucial that ACER, TSOs and developers, NRAs and standardisation bodies are part of the implementation process in order to guide ENTSO-E in the drafting of the Network Code. In the drafting of grid codes, it is common process that ACER guides ENTSO-E. It is therefore common to involve ACER, which would also be applicable in the drafting of the offshore HVDC grid code

5.5 GOVERNMENTS OF NORTH SEAS STATES

Governments of North Seas states are 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, or an arm's length body, are responsible for issuing permits that have to be in place before the start of the construction.

5.5.1 DIRECT RECOMMENDATIONS

5.5.1.1 STREAMLINE PLANNING AND PERMITTING PROCEDURES

Governments can work together to streamline the planning and permitting processes, for example through creating a one-stop-shop for key project permits in cross-border projects to reduce the number of permits required, shorten the process for acquiring the permits and the number of authorities involved. 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.

Governments should also allow some flexibility in permits to take into account technology developments between the point a permit is issued and the start of construction. This would allow the most cost-effective solution available to be chosen.

5.5.1.2 DEVELOP A MIXED PARTIAL AGREEMENT ("NORTH SEA TREATY") FOR REGIONAL COOPERATION

In the short-term, governments in EU member states can transpose new EU provisions on offshore hybrid asset into domestic legislation (see DG Energy actions). However, 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.

5.5.1.3 ENSURE THE QUALITY AND QUANTITY OF SKILLED PERSONNEL

As explained in the government recommendations, the government can support skills development and training to supply the North Seas states with a well-trained workforce. This has a direct benefit on the establishment of the supply chain (described above) and the development of the MOG.

5.5.1.4 SUPPORT THE ESTABLISHMENT OF A SUPPLY CHAIN

Governments are able to play a direct role in the roll-out of the MOG by investing in infrastructure that is necessary to establish a supply chain, as far as it is within State Aid rules. Additionally, they can foster innovation and investment through their tax system and by lowering the cost of capital for a project. With the increase of tangible (i.e. more labour) and intangible benefits (i.e. increase in technical knowledge), the governments' aid could result in a total benefit to the states.

5.5.1.5 PROJECT & PLANNING COORDINATION

The responsibility of coordinating/planning projects and allowing the anticipatory investments for multi-terminal extension lies with associations such as governments. Therefore, governments will be directly involved in the recommendations listed under project & planning coordination, together with DG-Energy, ENTSO-E, ACER, national regulatory authorities and TSOs and developers. This means governments are recommended to work together with these stakeholders to:

- Update system operation guidelines
- Enable multi-purpose infrastructure use
- Update TYNDP process to identify beneficial multi-terminal grid extensions
- Establish hubs in places with high wind energy generation density
- Allow the application of anticipatory investments in the grid

5.5.1.6 TOPOLOGICAL COMPATIBILITY

Next to this, the governments are responsible for implementation of the topological compatibility recommendations. These have the same actors as those mentioned under Project & planning coordination. This means governments are recommended to work together with the same stakeholders to:

- Standardise rated HVDC voltages
- Coordinate converter configuration
- Coordinate ancillary services
- Coordinate system earthing
- Coordinate short-circuit withstand
- Anticipate spare bay and space
- Standardise offshore HVDC platforms

5.5.1.7 ENABLE NATIONAL REGULATORY AUTHORITIES TO COOPERATE TO REGULATE THE OFFSHORE GRID

Governments can encourage 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.

5.5.2 INDIRECT RECOMMENDATIONS

5.5.2.1 ESTABLISH HUBS IN PLACES WITH HIGH WIND ENERGY GENERATION DENSITY

The optimal location and the construction of an artificial island will be identified by the TSO, but with the North Seas being a heavily used area by multiple parties, the governments of member states, along with others, will be required to be consulted in the final decision of the location of the island.

5.6 NATIONAL REGULATORY AUTHORITIES

5.6.1 DIRECT RECOMMENDATIONS

5.6.1.1 ENABLE NATIONAL REGULATORY AUTHORITIES TO COOPERATE TO REGULATE THE OFFSHORE GRID

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 remuneration mechanisms for transmission owners and operator and oversee the development of operational frameworks etc. For the offshore hybrid assets connected in a MOG, income should be based on regulated income rather than on congestion revenue.[50]

5.6.1.2 AUTHORISE APPROPRIATE ANTICIPATORY INVESTMENTS

It is up to the NRAs to determine whether to remunerate anticipatory investments in the offshore grid. The NRAs usually regulate the amount of money TSOs spend on the construction of assets to ensure that money is fairly spent. Anticipatory investments are, therefore, usually not allowed as these investments could be avoided for the particular section of the offshore grid that is established first. Allowing anticipatory investments, can be cost-effective over the longer-term, providing there is a degree of certainty over where and when OWFs will be built.

5.6.1.3 INTRODUCE THE SMALL BIDDING ZONES MARKET MODEL

The NRAs will be the implementation responsible party for the small bidding zones market model. In the current bidding zone review, the TSOs summit their proposal for the bidding zones, which will be evaluated by the NRAs – as a first step. It is therefore proposed that the same structure can be followed for the small bidding zones model, where TSOs determine the bidding zones and NRAs have the final decision in the determination of the zones.

5.6.1.4 PROJECT & PLANNING COORDINATION

The responsibility of coordinating/planning projects and allowing the anticipatory investments for multi-terminal extension lies with international associations such as NRAs. Therefore, NRAs will be directly involved in the recommendations listed under project & planning coordination, together with DG-Energy, ENTSO-E, ACER, national governments, and TSOs and developers. This means NRAs are recommended to work together with these stakeholders to:

- Update system operation guidelines

[50] This conclusion is also supported from the financial perspective [32].

- Enable multi-purpose infrastructure use
- Update TYNDP process to identify beneficial multi-terminal grid extensions
- Establish hubs in places with high wind energy generation density
- Allow the application of anticipatory investments in the grid

5.6.1.5 TOPOLOGICAL COMPATIBILITY

Next to this, the NRAs are responsible for implementation of the topological compatibility recommendations. These have the same actors as those mentioned under Project & planning coordination. This means NRAs are recommended to work together with the same stakeholders to:

- Standardise rated HVDC voltages
- Coordinate converter configuration
- Coordinate ancillary services
- Coordinate system earthing
- Anticipate spare bay and space
- Standardise offshore HVDC platforms

5.6.1.6 CONTRACTUAL COMPATIBILITY

The NRAs are one of the responsible parties to ensure contractual interoperability. Together with ENTSO-E and TSOs and developers and with the help of manufactures, the NRAs is recommended to implement contractual compatibility.

5.6.2 INDIRECT RECOMMENDATIONS

5.6.2.1 ESTABLISH AN OFFSHORE HVDC NETWORK CODE

Although ENTSO-E is the party responsible for implementation, it is also crucial that ACER, TSOs and developers, NRAs and standardisation bodies are part of the implementation process in order to guide ENTSO-E in the drafting of the Network Code.

5.7 NATIONAL PLANNING AUTHORITIES

5.7.1 DIRECT RECOMMENDATIONS

5.7.1.1 STREAMLINE PLANNING AND PERMITTING PROCEDURES

National planning authorities and other bodies responsible for seabed leases (e.g. the Crown Estate in the UK) 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 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.

5.8 TRANSMISSION SYSTEM OPERATORS AND DEVELOPERS

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 offshore (design, build and maintain) and a system operator (SO) for the national transmission system. For example, in the UK, OWF developers design and build the transmission connection from their wind farm to the onshore network, then transfer the ownership and maintenance responsibilities to an Offshore Transmission Owner (OFTO), while the overall system is managed by the SO, National Grid ESO. This section refers to TSOs and other grid developers when describing the entity(-ies) responsible for designing, building and maintaining and operating of the offshore and onshore grid. The role of the TSOs and developers is very important and thus they must fulfil a list of recommendations that are crucial for the success of multi-terminal projects.

5.8.1 DIRECT RECOMMENDATIONS

5.8.1.1 AUTHORISE APPROPRIATE ANTICIPATORY INVESTMENTS

It is up to TSOs to make a case for anticipatory investments and show the implementer, i.e. governments and NRAs, that these investments are required for the efficient roll-out of an offshore grid. The TSOs are actively engaged in the reviews for price control and will thus also play an active role in advocating for anticipatory investments.

5.8.1.2 INTRODUCE THE SMALL BIDDING ZONES MARKET MODEL

The TSOs will be the end-user of the small bidding zones market model, that will have to be implemented by NRAs. It will have a direct effect on the day-to-day operations of TSOs, which means they will also need to be involved in the design (as indicated below).

5.8.1.3 PROJECT & PLANNING COORDINATION

The responsibility of coordinating/planning projects and allowing the anticipatory investments for multi-terminal extension lies with international associations such as TSOs and developers. Therefore, TSOs and developers will be directly involved in the recommendations listed under project & planning coordination, together with DG-Energy, ENTSO-E, ACER, national governments, NRAs. This means TSOs and developers are recommended to work together with these stakeholders to:

- Update system operation guidelines
- Enable multi-purpose infrastructure use
- Update TYNDP process to identify beneficial multi-terminal grid extensions
- Establish hubs in places with high wind energy generation density
- Allow the application of anticipatory investments in the grid

TSOs and developers will also be involved as the parties that will utilise the outcomes of these recommendations directly in the construction of the offshore grid.

5.8.1.4 TOPOLOGICAL COMPATIBILITY

Next to this, the TSOs and developers are responsible for implementation of the topological compatibility recommendations. These have the same actors as those mentioned under Project & planning coordination. This means TSOs and developers are recommended to work together with the same stakeholders to:

- Standardise rated HVDC voltages
- Coordinate converter configuration

- Coordinate ancillary services
- Coordinate system earthing
- Anticipate spare bay and space
- Standardise offshore HVDC platforms

TSOs and developers will also be involved as the parties that will utilise the outcomes of these recommendations directly in the construction of the offshore grid.

5.8.1.5 ESTABLISH AN OFFSHORE HVDC NETWORK CODE

TSOs and developers are the parties directly influenced by the HVDC Network Code, as they are responsible for the planning and construction of the grid and should therefore comply to the Network Code.

5.8.1.6 ENSURE STABLE OPERATION AND CONTROL

The responsibility to ensure operational stability lies with the party responsible for construction of the offshore grid, i.e. the TSOs and other developers, and is influenced by the vendors of HVDC converters and OWF developers and operators. TSOs are therefore the responsible party to implement the operational stability and, as grid operators, will also be the final user of this recommendation.

5.8.1.7 CHOOSE AND IMPLEMENT AN APPROPRIATE PROTECTION SYSTEM

Depending on the size and the topology of an HVDC transmission system and the characteristics of the AC grids that it connects to, an HVDC grid protection system may have to be installed to limit or mitigate the adverse effects of system faults or short-circuits. As such, the responsibility of the protection system lies with the parties responsible for grid development; the TSOs and other developers.

5.8.1.8 VENDOR INTEROPERABILITY

TSOs and developers are one of the responsible parties to ensure vendor interoperability. Together with ENTSO-E and with the help of manufactures and OWF developers, TSOs and developers are recommended to:

- Develop Models and methods to ensure dynamic performance of multi-vendor HVDC systems
- Standardize communication interfaces
- Standardize mechanical interfaces

When this recommendation is implemented, the TSOs will also be the final user.

5.8.1.9 CONTRACTUAL COMPATIBILITY

TSOs and developers are one of the responsible parties to ensure contractual interoperability. Together with NRAs and ENTSO-E and with the help of manufacturers, TSOs and developers are recommended to implement contractual compatibility. TSOs will then also be the end user of the recommendation.

5.8.1.10 FURTHER RESEARCH, DEVELOPMENT & DEMONSTRATION

In all areas where more research work needs to be done, TSOs and developers can facilitate the research and take on research areas that are of interest of TSOs and developers. TSOs and developers can use the incentives supplied by DG Energy to cooperate with the other stakeholders, i.e. ENTSO-E and manufacturers, to:

- Initiate full-scale multi-vendor, multi-purpose, multi-terminal HVDC network pilot
- Explore the need for flexibility in the system
- Perform integrated AC/DC system studies

- Carry out research into offshore wind farm advanced capabilities
- Analyse the HVDC hub topology
- Continue DC switchgear development
- Focus effort on Interoperability of controls and protection
- Research the need for DC/DC converters in the system

Additionally, TSOs and developers are the direct users of knowledge gained within the research carried out.

5.8.2 INDIRECT RECOMMENDATIONS

5.8.2.1 INTRODUCE THE SMALL BIDDING ZONES MARKET MODEL

The TSOs will have to be involved in establishing the small bidding zones market model in order to fully understand the market model and signal problems or opportunities when drafting the legislation required to implement the model.

5.8.2.2 ESTABLISH AN OFFSHORE HVDC NETWORK CODE

Although ENTSO-E is the party responsible for implementation, it is also crucial that ACER, TSOs and developers, NRAs and standardisation bodies are part of the implementation process in order to guide ENTSO-E in the drafting of the Network Code.

5.9 OFFSHORE 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 MOG.

5.9.1 INDIRECT RECOMMENDATIONS

5.9.1.1 DEVELOP GRID-WIDE SUPPORT SCHEMES FOR OWFS

The roll out of the small bidding zones or connection to hybrid assets will have implications for the applicability of different national support schemes. OWF Developers will be key stakeholders feeding into the development of new cross-border support schemes.

5.9.1.2 ENSURE THE QUALITY AND QUANTITY OF SKILLED PERSONNEL

During the development of programmes to train skilled personnel, it is essential the wind farm developers get involved in the process. This ensures that the training is geared towards, amongst others, the skills necessary to be applied in the core business of wind farm developers.

5.9.1.3 ENSURE STABLE OPERATION AND CONTROL

Operational stability of HVDC grids and any connected offshore AC grids is determined by the characteristics of the converter and the offshore wind turbine and wind farm control systems. Together with the converter manufacturers, OWF developers and operators will therefore be essential in ensuring stable operation and control of the MOG.

5.9.1.4 VENDOR INTEROPERABILITY

Offshore wind farm operators will also have a role to play in ensuring vendor interoperability, as they have most of the knowledge on the specifications of their wind farms. It is therefore important that also offshore wind farm operators participate in the establishment of vendor operability to ensure operability of components in the offshore grid.

5.10 MANUFACTURERS

Equipment manufacturers, also referred to in this document as vendors, 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.

5.10.1 DIRECT RECOMMENDATIONS

5.10.1.1 ENSURE THE QUALITY AND QUANTITY OF SKILLED PERSONNEL

The manufacturers are end-users of the skilled personnel that would be trained through the implementation of this recommendation. Along with other stakeholders, it is essential that a well-trained workforce is available in all sectors of the MOG – from OWF developers to grid component manufacturers and grid developers.

The manufacturers are one of the end-users of the supply chain, as they will choose the locations in which there is a smooth operation of their core business.

5.10.1.2 FURTHER RESEARCH, DEVELOPMENT & DEMONSTRATION

In all areas where more research work needs to be done, manufacturers can facilitate the research and take on research areas that are of interest of manufacturers. manufacturers can use the incentives supplied by DG Energy to cooperate with the other stakeholders, i.e. ENTSO-E and TSOs and developers, to:

- Initiate full-scale multi-vendor, multi-purpose, multi-terminal HVDC network pilot
- Explore the need for flexibility in the system
- Perform integrated AC/DC system studies
- Carry out research into offshore wind farm advanced capabilities
- Analyse the HVDC hub topology
- Continue DC switchgear development
- Focus effort on Interoperability of controls and protection
- Research the need for DC/DC converters in the system

Additionally, manufacturers are the direct users of knowledge gained within the research carried out.

5.10.2 INDIRECT RECOMMENDATIONS

5.10.2.1 SUPPORT THE ESTABLISHMENT OF A SUPPLY CHAIN

During the implementation of an environment in which a supply chain can be set-up, manufacturers should have the opportunity to indicate their preferences and needs.

5.10.2.2 ENSURE STABLE OPERATION AND CONTROL

Operational stability of HVDC grids and any connected offshore AC grids is determined by the characteristics of the converter and the offshore wind turbine and wind farm control systems. Together with the OWF developers and operators, converter manufacturers will therefore be essential in ensuring stable operation and control of the MOG.

5.10.2.3 CHOOSE AND IMPLEMENT AN APPROPRIATE PROTECTION SYSTEM

Depending on the size and the topology of an HVDC transmission system and the characteristics of the AC grids that it connects to, an HVDC grid protection system may have to be installed to limit or mitigate the adverse effects of system faults or short-circuits. As such, the responsibility of the protection system lies with the parties responsible for grid development; the TSOs and developers. It is, however, also important manufacturers supply the TSOs and developers with the correct information on the DCCBs and other equipment required in the protection system so that TSOs can make the best informed decision on the establishment of a protection system.

5.10.2.4 VENDOR INTEROPERABILITY

Manufacturers will have a role to play in ensuring vendor interoperability, as they have most of the knowledge on the specifications of the equipment. It is therefore of the upmost importance manufacturers participate in the establishment of vendor operability.

5.10.2.5 CONTRACTUAL COMPATIBILITY

There is a role for manufacturers in the contractual compatibility, especially concerning the terminology and definitions used for the equipment and the exchange of information on different equipment. Manufacturers are therefore recommended to work together with the other stakeholders to be able to ensure contractual compatibility.

5.11 OTHERS

5.11.1 DIRECT RECOMMENDATIONS

5.11.1.1 DEVELOP CONSISTENT DECOMMISSIONING GUIDELINES FOR OFFSHORE ASSETS

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

5.11.2 INDIRECT RECOMMENDATIONS

5.11.2.1 ESTABLISH AN OFFSHORE HVDC NETWORK CODE

Although ENTSO-E is the party responsible for implementation, it is also crucial that ACER, TSOs and developers, NRAs and standardisation bodies are part of the implementation process in order to guide ENTSO-E in the drafting of the Network Code.

5.11.2.2 ENSURE THE QUALITY AND QUANTITY OF SKILLED PERSONNEL

The establishment of learning centres for skilled personnel can be influenced by other stakeholders in the industry that have an interest both in education as well as offshore wind, i.e. regional authorities, universities, and should be implemented in close collaboration with them.

5.11.2.3 DEVELOP CONSISTENT DECOMMISSIONING GUIDELINES FOR OFFSHORE ASSETS

The development of decommissioning guidelines will require input from OWF developers, TSOs, planning authorities, environmental researchers and government bodies. Research into the impacts of different decommissioning strategies should also be implemented.

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. 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 to have it in place. An indication is also made of the time required to implement the recommendation, which may mean that work on the recommendation may start in an earlier period. 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.

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. When each recommendation is necessary is based on the development of the grid topologies of Deliverable 12.2 over time. For each of the periods below, a short description of the roll-out is included.

An indication of the time required to implement each of the recommendations is given. 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.

6.1 THE PERIOD 2020 – 2030

Out to 2030, roll out of offshore transmission largely follows current practices, except for the use of 525 kV 2 GW HVDC components (not yet deployed in 2020) and the need for anticipatory investments. However, many of the technological recommendations should already be implemented in order to allow the grid to naturally evolve into an offshore grid with multi-terminal and meshed elements. In order to allow a multi-purpose, multi-actor, multi-vendor, multi-national MOG to develop, the assumption of compatibility needs to be turned into reality through the formulation of a set of explicit technology and purpose-agnostic minimum requirements which all actors in the MOG development need to adhere to. Therefore, even in the early stages of grid development, the key technology recommendations will be required to be implemented. For example, the establishment of an offshore HVDC network code can facilitate meshing of the grid in later periods as it will allow grid developers to independently develop the offshore grid according to similar characteristics, allowing for meshing in later periods. Many of the technology recommendations should be implemented as soon as possible. In our prognosis we construct island Hubs early on. Due to a long regulatory lead-time up to the construction of an island hub, this is optimistic. The first hub may only be operational by 2030 at the earliest, with only a short period between construction and operation once the regulation is settled.

As much of the offshore grid development in this period is similar to the current offshore grid practices, many of the same regulations can still apply in this period. However, a pilot project to test the small bidding zones model should be established and a decision made about its wider rollout. Additionally, due to some locally multi-terminal and meshed configurations, anticipatory investments should be allowed in some North Sea countries, where there is a high degree of certainty that neighbouring windfarms or interconnection will be constructed.

The planning of offshore wind generation sites will require a more extensive planning and coordination to gain maximum benefit from potential meshing and or large hub or islands. This may need to be delegated to smaller groups to have more goal directed and pragmatic action. This should also bridge to a strengthened role for umbrella organisations such as ENTSO-E and ACER to coordinate improved coordination between bottom-up short term plans and longer term system plans. This should also implement a coherent regulatory environment.

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 the EEZ in which 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.

Finally, 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, the progress made and the concerned stakeholders is presented in Table 10 below.

Table 10 - Actions, their timing and the stakeholders in the period 2020 – 2030. (Prep = Start Preparations, Impl = Start Implementation, Nec = Necessary by).

ACTION	PREP	IMPL	NEC	PROGRESS	EXPLANATION	IMPLEMENTER	INFLUENCER	USER
North Sea Treaty: Develop a Mixed Partial Agreement for Regional Cooperation	2020	2025	2030	None	Required content identified in PROMOTioN but no progress on drafting of a treaty.	EC and National Governments	EC, National Governments, NRAs, Transmission Owners and OWF developers	NRAs, TSOs and OWF developers
Market model trials: Carry out pilot and decide on introducing the small bidding zones market model	2020	2024	2025	Final	The small bidding zones model is consistent with the EU's Clean Energy Package but a trial project is needed to test its practicality.	NRAs	EC, National Governments, TSOs and developers, System OWF developers	TSOs and developers, OWF developers,
Market model implementation: Introducing the small bidding zones market model	2025	2027	2030	Final	No change in transmission asset regulation required, changing the market setup requires some time.	NRAs	OWF Developers, TSOs, NRAs, Governments, EC	Utilities, TSOs
Offshore hybrid asset: Create a robust legal definition of Offshore hybrid assets	2020	2028	2030	Ongoing	There is a definition in the Recitals of the Electricity Regulation, but a detailed approach to regulating these assets has not been implemented. This should be developed in parallel with market model solutions.	EC (Short-Term), EC and National Governments (long term)	EC, National Governments, NRAs, Transmission Owners and OWF developers	NRAs, TSOs and OWF developers
Project Pipelines: Develop long-term project pipelines and streamline the planning process	2020	2025	2030	Ongoing	Although implemented in the North Sea states separately, there is no alignment yet among the states.	EC, NRAs	OWF Developers, TSOs, NRAs, Governments, EC	TSOs, OWF developers
Anticipatory investments: Authorise appropriate anticipatory investments	2020	2022	2025	Ongoing	Decisions on anticipatory investment are taken at a national level	Governments (in some cases delegated to NRAs)	Transmission Owners and Operators, NRAs, OWF Developers	TSOs, OWFs
Grid Regulation: Enable National Regulatory Authorities to cooperate to regulate the offshore grid	2020	2025	2030	Ongoing	Concept of Regional Cooperation Centres in place, but no decision on who regulates a MOG.	NRAs	EC, National Governments, NRAs, ACER (Coordination)	NRAs, TSOs, OWF developers

ACTION	PREP	IMPL	NEC	PROGRESS	EXPLANATION	IMPLEMENTER	INFLUENCER	USER
Investment models: Ensure sufficient investment can be reached	2020	2025	2027	Ongoing	In progress – allowed in some countries.	TSOs, National Governments, NRAs	TSOs, National Governments, Financial institutions, NRAs, Consumer Groups	TSOs, Financial Providers
System operation guidelines: Update system operation guidelines	2020	2022	2023	Ongoing	Research started within PROMOTioN. As early implementation can facilitate meshing in later periods, this recommendation should be implemented as soon as possible.	DG Energy, ENTSO-E, ACER, national governments, national regulating authorities, TSOs and developers		TSOs and developers
Multi-purpose infrastructure: Enable multi-purpose infrastructure use	2020	2023	2025	Ongoing	Research started within PROMOTioN. As early implementation can facilitate meshing in later periods, this recommendation should be implemented as soon as possible.	DG Energy, ENTSO-E, ACER, national governments, national regulating authorities, TSOs and developers		TSOs and developers
TYNDP process: Update TYNDP process to identify beneficial multi-terminal grid extensions	2020	2023	2025	Ongoing	Research started within PROMOTioN. As early implementation can facilitate meshing in later periods, this recommendation should be implemented as soon as possible.	DG Energy, ENTSO-E, ACER, national governments, national regulating authorities, TSOs and developers		TSOs and developers
Hubs: establish artificial islands in places with high wind energy generation density	2020	2025	2030	Ongoing	Research started within PROMOTioN. As early implementation can facilitate meshing in later periods, this recommendation should be implemented as soon as possible.	DG Energy, ENTSO-E, ACER, national governments, national regulating authorities, TSOs and developers		TSOs and developers
Anticipatory investments: Allow the application of anticipatory investments in the grid	2020	2025	2027	Ongoing	Research started within PROMOTioN. As early implementation can facilitate meshing in later periods, this recommendation should be implemented as soon as possible.	DG Energy, ENTSO-E, ACER, national governments, national regulating authorities, TSOs and developers		TSOs and developers
Topological compatibility: Ensure the implementation of the recommendations that lead to topological compatibility	2020	2022	2025	Ongoing	Research started within PROMOTioN. As early implementation can facilitate meshing in later periods, this recommendation should be implemented as soon as possible.	DG Energy, ENTSO-E, ACER, national governments, national regulating authorities, TSOs and developers		TSOs and developers

ACTION	PREP	IMPL	NEC	PROGRESS	EXPLANATION	IMPLEMENTER	INFLUENCER	USER
Offshore HVDC network code: Establish an offshore HVDC network code	2020	2022	2025	Ongoing	Research started within PROMOTioN. As early implementation can facilitate meshing in later periods, this recommendation should be implemented as soon as possible.	ENTSO-E	ACER, TSOs and developers, manufacturers and standardisation bodies	TSOs and developers
Stable operation and control: Ensure stable operation and control of the Meshed Offshore Grid	2020	2022	2025	Ongoing	Research started within PROMOTioN. As early implementation can facilitate meshing in later periods, this recommendation should be implemented as soon as possible.	TSOs and developers	Manufacturers, OWF developers	TSOs and developers
Vendor interoperability: Implement the recommendations that lead to vendor compatibility	2020	2022	2025	Ongoing	Research started within PROMOTioN and EC. As early implementation can facilitate meshing in later periods, this recommendation should be implemented as soon as possible.	ENTSO-E, TSOs and developers	Manufacturers, OWF developers	TSOs and developers
Contractual compatibility: Develop a best practise or guideline to guarantee contractual compatibility	2020	2025	2027	Ongoing	Research started within PROMOTioN	ENTSO-E, TSOs and developers, NRAs	Manufacturers	TSOs and developers

6.2 THE PERIOD 2030 – 2040

As the rate of grid development increases over this period, the solutions for the control systems and DCCBs necessary for protection should be ready for deployment. Additionally, interoperability issues and multi-vendor integration of infrastructure should be understood. 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 the further studies of the small bidding zones market model are successful, they should be rolled out more widely during this period. The alternative is to progress with the development of a regulatory regime for offshore hybrid assets.

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, and potentially the introduction of small bidding zones, the remuneration of offshore wind farms 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. The recommendations to the stakeholders and their progress are presented below in Table 11.

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 multi-terminal and meshed grids to create a highly complex multi-terminal and meshed grid. Research on decommissioning impacts should lead to the development of guidelines for OWFs and transmission infrastructure in this period, if not before. This action is presented in Table 12 below.

6.4 THE PERIOD 2020 – 2050

Some recommendations will run from the start up to the end of the analysed period. This includes the research on protection systems and all recommendations included in the technology section on further research, development and demonstration. The recommendations, their timing and the stakeholders are presented in Table 13 below.

Table 11 - Actions, their timing and the stakeholders in the period 2030 – 2040. (Prep = Start Preparations, Impl = Start Implementation, Nec = Necessary by).

ACTION	PREP	IMPL	NEC	PROGRESS	EXPLANATION	IMPLEMENTER	INFLUENCER	USER
Skilled personnel: Ensure the quality and quantity of skilled personnel	2025	2035	2035	Ongoing	No specified programs for HVDC transmission implemented.	Governments	Schools/Universities/Supply Chain/ TSOs/OWF developers	Supply Chain/ TSOs and developers
Supply chain: Support the establishment of a supply chain	2030		2035	Ongoing	Although there are European manufacturers, there is no specific supply chain set up.	Governments	Manufacturers OWF developers/ TSOs/ others	OWF developers/ TSOs and developers
Support schemes: Develop grid-wide support schemes for OWFs	2025	2030	2035	Ongoing	The EU has frameworks for joint supports schemes which can be built upon	Governments/ NRAs	TSOs/OWF Developers/ Consumer Groups	OWF developers

Table 12 - Actions, their timing and the stakeholders in the period 2030 – 2040. (Prep = Start Preparations, Impl = Start Implementation, Nec = Necessary by).

ACTION	PREP	IMPL	NEC	PROGRESS	EXPLANATION	IMPLEMENTER	INFLUENCER	USER
Decommissioning Guidelines: develop consistent decommissioning guidelines for offshore assets	2020	2045	2045	Ongoing	National Guidelines are in place. Harmonisation required but decommissioning guidelines not necessary in the near future.	IMO or OSPAR	National Governments, OWF Developers, TSOs, Third party construction, NRAs, EC	TSOs, OWF Developers

Table 13 - Actions, their timing and the stakeholders in the period 2020 – 2050. (Prep = Start Preparations, Impl = Start Implementation, Nec = Necessary by).

ACTION	PREP	IMPL	NEC	PROGRESS	EXPLANATION	IMPLEMENTER	INFLUENCER	USER
Protection strategy: Choose and implement an appropriate protection system		2020	2050	Ongoing	The protection strategy can be chosen by each TSO separately, according to PROMOTioN analysis. Which strategy is necessary where is still to be further researched.	TSOs	Manufacturers	TSOs
Further research: Further technological research, development and demonstrations		2020	2050	Ongoing	Further technological research, development and demonstration recommendations will be carried on within the analysed period. These could run up to and even past 2050, or be completed anywhere within the period.	DG Energy, ENTSO-E, TSOs, manufacturers and developers		TSOs and developers, manufacturers

6.5 ROADMAP TO A MESHED OFFSHORE GRID

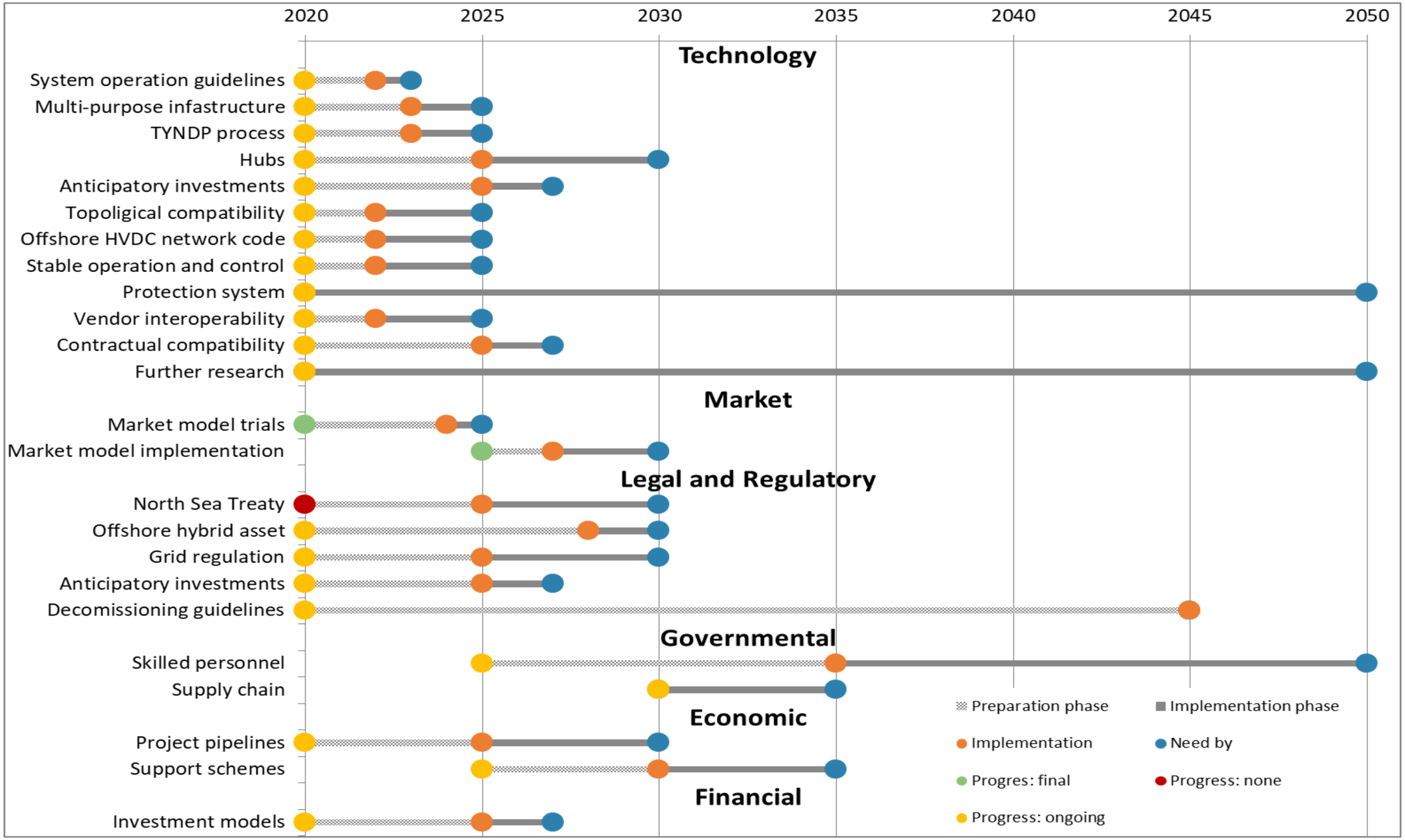

Figure 28 - Roadmap to a Meshed Offshore Grid, presenting the recommendations, their progress and their timing.

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APPENDIX I - GRID CONCEPTS

To understand the costs and benefits of HVDC multi-terminal and meshed networks, three different multi-terminal and 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, where offshore wind farms are connected point-to-point. This appendix details the design criteria and philosophies behind each concept.

These three multi-terminal and meshed grid concepts are not the only way a multi-terminal and meshed offshore grid could develop; the eventual development of the grid could use elements of all three. However, the PROMOTioN consortium agrees these three multi-terminal and meshed grid concepts plus the Business as Usual scenario cover 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 point-to-point connections. Various wind parks are either individually connected to shore with AC or DC lines or grouped into clusters to reach a critical size of 2 GW in order for power to be evacuated along standardised 525 kV 2 GW DC bipole cables to shore. For short distances AC lines can be used. Connections between the electricity grids of different countries are made by dedicated lines, called interconnectors (such as BritNed/NEMO link). This is shown in Figure 29[51]. The Business as Usual (BAU) concept contains no new configurations but does assume continuation of current technology development trends, such as the deployment to 2 GW DC transmission cables.

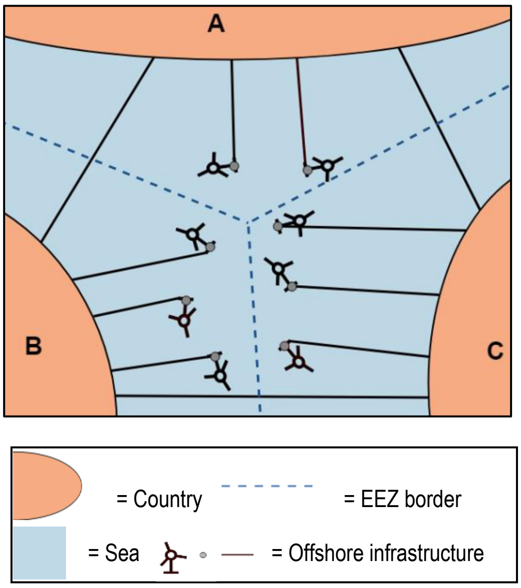


Figure 29 Business-as-Usual design philosophy

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

NATIONAL DISTRIBUTED HUBS

The National Distributed Hubs concept (NAT) 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 Exclusive Economic Zone (EEZ) to 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. The grid architecture, however, is typically not founded on them (Figure 30)[51].

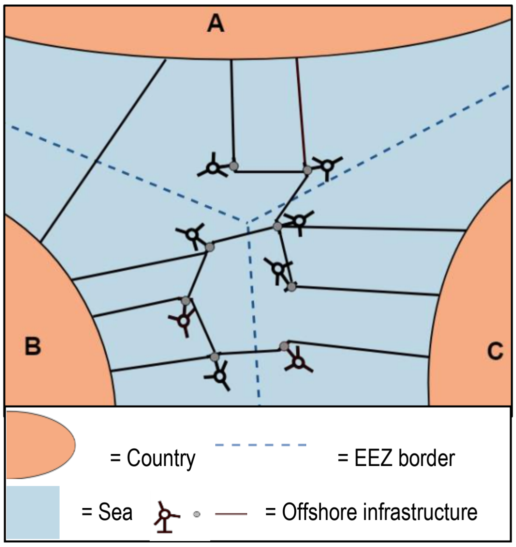


Figure 30 National Distributed Hubs design philosophy

NAT allows for hybrid use of cables, blurring the difference between wind energy evacuating cables and interconnections. As OWFs of two countries might be 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 is only technically feasible if they operate at the same voltage[52]. Like in BAU, separate point-to-point interconnectors might at times still be economical, but within NAT interconnecting via another park is also possible.

NAT allows for meshing of the connection, meaning that multiple OWFs of one country can also be connected to one another through a DC connection. Next to the establishment of interconnection, this can have two additional benefits. Firstly, two OWFs might connect to each other and share a larger, more economic cable. Secondly, groups might be connected in a ring-like topology. This way the option of transporting power over the alternative paths can still be open when an individual link is unavailable. At present this topology is relatively new and the only interconnector similar to such kind[53] is Kriegers Flak Combined Grid Solution between East Denmark and Germany via German and Danish[54] offshore wind power plants.

[52] 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
[53] 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.
[54] The Danish OWFs and the interconnector are in commissioning at the time of writing.

EUROPEAN CENTRALISED HUBS

The European Centralised Hubs concept (HUB) proposes the creation of several central hubs to evacuate offshore wind generation, in order to optimise on economies of scale for installation costs. These central hubs have two main benefits: reduced cost and the possibility of increased interconnection. The cost reductions are obtained due to the lower cost of offshore support structures. Support structures are a major cost-driver for offshore wind development, as placing large and heavy structures far into the sea is expensive. Placing converters on a hub (e.g. an island) instead of a platform could decrease these costs significantly. This topology proposes short-distance AC connections from OWFs to these hubs, as is currently done with close shore connections. A DC grid between the island and the various shores would be constructed to further evacuate the energy to land. Such a hub could be very large (up to 40 GW), and therefore will have multiple cable connections, likely with multiple countries. This yields the second benefit: as all power is grouped in one location, it is straightforward to connect and enable trading and/or dispatching to different connected regions. This means that HUB can provide a high amount of interconnection, especially during "low wind" timeframes. The design philosophy, showing only one central hub, is shown in Figure 31[51].

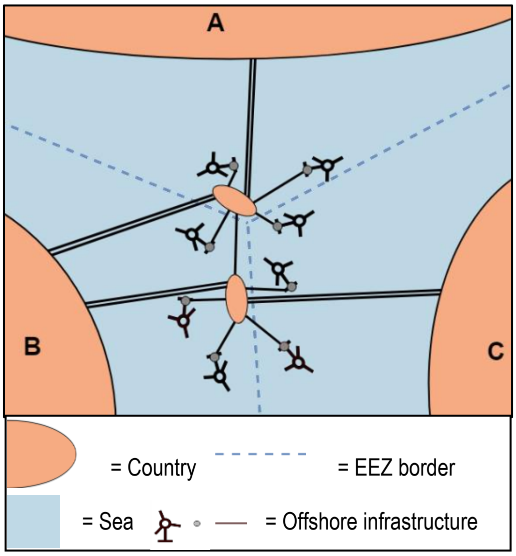


Figure 31- European Centralised design philosophy.

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. This means that technologically, building a hub is not necessarily complex. It would also be a good location to try out various DC interlinking options on a full scale in a practical environment without being instantly reliant on them, as an AC option still remains. Multiple hubs could be constructed in the North Seas which might, 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 platform-based hubs are spread out over the North Seas and connected to each other via HVDC connections, as is illustrated in Figure 32[51]. National borders are not seen 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 DC Circuit Breakers (DCCBs) and DC protection systems. The result is a highly resilient grid, where built-in ring topologies provide alternative pathways in case of a cable

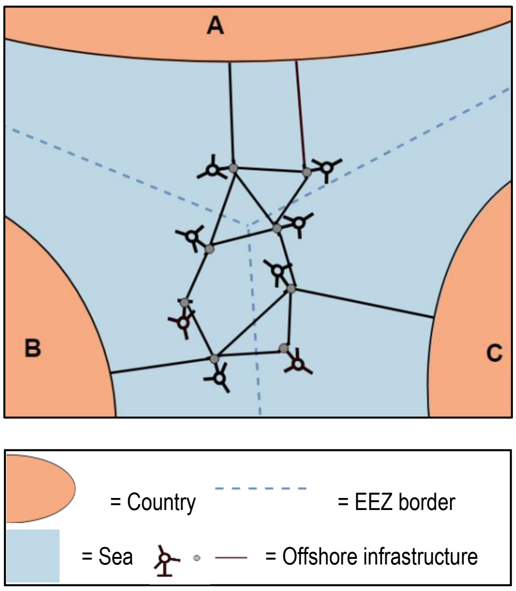


Figure 32 European Distributed design philosopy.

failure. However, the load flow in the resulting multi-terminal and meshed DC-network cannot be fully controlled by the existing converters anymore. This is an additional technical constraint to be taken into account by network design. It is therefore also the most advanced concept. This is similar in design philosophy to the onshore grid, although many differences still exist such as current type (AC vs. DC), cables vs. overhead lines and the level of redundancy.

APPENDIX II – 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 33 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 and are connected by a DC transmission line (DCL). This point-to-point example includes both Alternating Current Circuit Breakers (ACCBs) and Direct Current Circuit Breakers (DCCBs), although these are not strictly necessary in a point-to-point link. In the 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 the DC busbars in order to disconnect specific lines. Table 14 summarises all elements used in Figure 33 and their abbreviations.

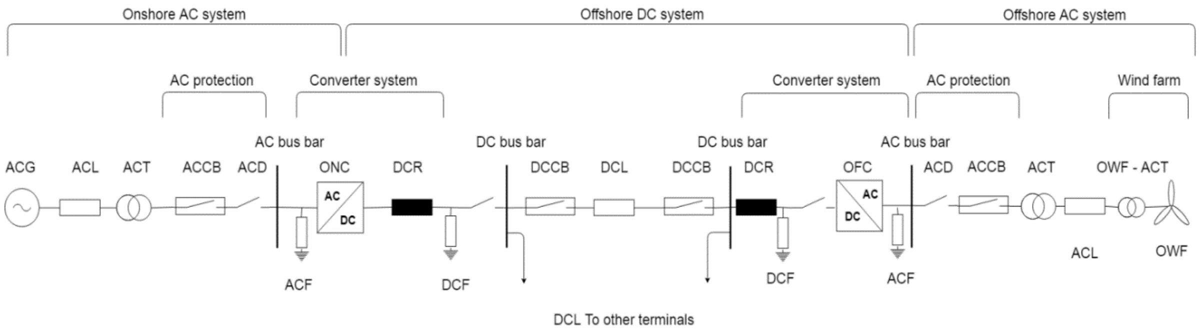


Figure 33- Representation of an HVDC system.

Table 14 - Components of an HVDC system.

Abbreviation	Name	Description
ACG	Alternating Current (AC) grid	A (meshed) network using Alternating Current.
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 and achieve galvanic isolation between different parts of the AC system. Often also a part of a converter system.
ACCB	AC circuit breaker	A protection system component, enabling 'interruption of AC fault currents' to isolate faulty electrical assets. In an AC/DC interface, this would protect the connecting AC side of the converter.
ACD	AC disconnector	An AC disconnector isolates different electrical assets form one another e.g. the converter from the AC system.

Abbreviation	Name	Description
ACF	AC filter	AC filters reduce harmonic distortion caused by the converters to the AC grid voltage.
ONC	Onshore converter	Connects the offshore DC grid to the onshore AC grid.
DCR	DC reactor	A DC reactor is installed to reduce high frequency harmonics and limit the rate of rise of a fault current.
DCF	DC filter	DC filters reduce harmonic distortion in the DC grid.
DCD	DC disconnector	A DC disconnector isolates different DC electrical assets from one another e.g. the converter from the DC transmission system.
DCCB	DC circuit breaker	A DC circuit breaker protects the connecting DC line, busbar or converter by interrupting DC faults currents and 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 between AC systems and provide galvanic isolation. 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 150/220 kV).
OWF	Offshore Wind Farm	-
Control and protection systems		
Type	**Name**	**Description**
Local	AC protection	Protection system that protects the converter station at the 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 individual and groups of 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.

Abbreviation	Name	Description
System	Offshore AC system	Control system that facilities operation of the offshore AC grid as a whole.

PRIMARY EQUIPMENT

Primary equipment includes items which are directly needed for the transport of power and typically also subjected to high voltages (and/or currents). Their main function is to provide uninterrupted, efficient and safe power flow from the generators to the onshore grid. The primary components include:

- Converters - Within PROMOTioN two key types of converters are considered; Voltage Source Converters (VSCs) and Diode Rectifying Units (DRUs). This appendix looks at both and how they may be configured.
- Transformers
- Switchgear
- Cables (DC and AC)
- Surge arrestors
- Instrumentation
- Earthing equipment

CONVERTERS

The role of power converters in the offshore grid is to control and process the flow of power between electrical systems with different electrical characteristics such as frequency or phase angles. As such they are used to convert AC to DC or vice versa, connect different unsynchronized AC systems, or interface with wind turbine generators which use a variable frequency to a fixed frequency AC grid. HVDC converters are used to supply currents and voltages in a form that is suitable for transmission of power or to convert HVDC power to AC for supply into the onshore AC grid. As shown in Figure 34, many HVDC converter topologies exist, differentiated by the type of power semi-conductor they use (e.g. diode, thyristor or Insulated Gate Bipolar Transistor [IGBT]) and the resulting converter's operational characteristics. Within PROMOTioN two key topologies of converters are considered, IGBT-based Modular Multi-level VSCs (MMC-VSCs) and DRUs. Which converter technology is applied depends on the grid system design and the application. Another converter type, thyristor-based Line Commutated Converters (LCC), is not in scope of PROMOTioN as it is considered only to be suitable in point-to-point or small point-to-point multi-terminal links between strong AC grids.

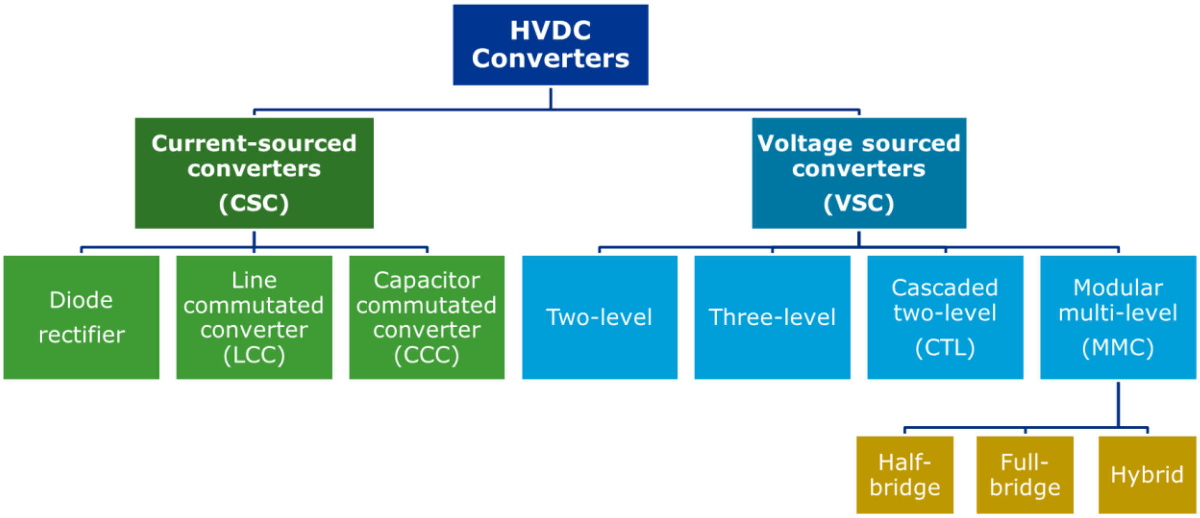


Figure 34- HVDC converter technologies.

It is common to class converter technologies according to their ability to deliver both polarities of DC voltage and current, as shown in Figure 35. From this figure it becomes immediately clear that when converters of different technologies are connected together, the range of possible operating points of the resulting system is reduced to the overlap of the operating characteristics of the converter technologies.

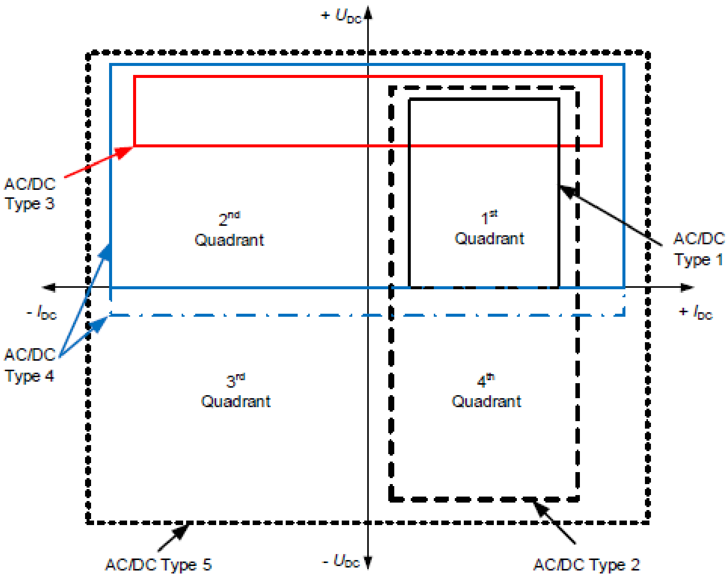


Figure 35 – Converter types in terms of operating characteristics [4]

VOLTAGE SOURCE CONVERTER

The VSC can generate AC voltages from DC voltages and vice-versa. The advantage of VSCs over other converter topologies is that it is possible to control DC or AC output voltage, control reactive and active power independently, and control the frequency, magnitude and phase angle. In addition, unlike LCCs, HVDC-VSCs are able to reverse power flow by reversing the current flow rather than by reversing the voltage polarity. Hence, VSCs enable bidirectional power flow, can be used in both point-to-point and multi-terminal and meshed topologies, and can be implemented in a branch that both connects OWFs and allows power exchange between countries through the offshore grid.

Similar to LCCs, the power electronic devices in VSCs are air-insulated and thus require a large clearance distance in air, which leads to large platform dimensions. This is an important limitation for the installation of VSCs on offshore platforms, whose cost significantly increases when the volume and weight of the components on top increase.

The state-of-the-art in VSC technology are so-called modular multi-level converters (MMCs) which can recreate smooth high voltage AC and DC voltage waveforms through the controlled series connection of varying numbers of small (< 2,5 kV which is less than 1% of the typical HVDC voltages) charged capacitors. This way, a 'stepped' sinusoidal waveform can be created with low harmonic distortion and low semi-conductor switching frequency, which in turn leads to high conversion efficiency. The modular nature of the MMC topology means that it is relatively easy to achieve high voltage ratings and that additional redundancy can be built in to by-pass faulty submodules without affecting the converter operation, leading to high availability. MMC-VSCs can generally be realized with a Half Bridge (HB) or Full Bridge (FB) submodule (SM) formation.

Figure 36 - VSC converter valves.

HALF BRIDGE

The HB-SM includes two IGBTs[55] (S1 and S2 in Figure 37) and a capacitor. 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-MMCs cannot over-modulate, operate at reduced DC voltages 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 and DC inductance have to be designed to limit the fault currents or SM by-pass thyristors with a higher current withstand capability are needed.

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

FULL BRIDGE

The FB modules, on the other hand, are able to generate negative voltages. This is thanks to two extra IGBTs (Figure 37) per SM in comparison to the half-bridge MMC. As a result, blocking of a full bridge MMC can result in an interruption of the DC fault current. It is also possible to insert the capacitor in reverse, enabling full bridge converters to operate at reduced DC voltages and even control a DC fault current to zero. This additional functionality comes at the cost of additional IGBTs which in turn lead to additional CAPEX, additional losses, increased submodule failure rate and additional weight and volume.

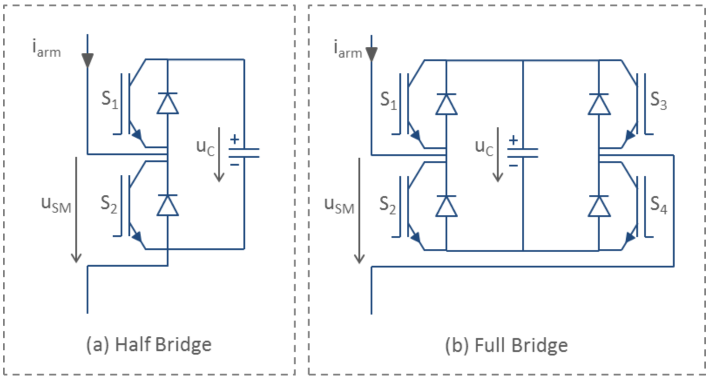


Figure 37 - Half bridge and full bridge topology

DIODE RECTIFIER UNIT

DRU-HVDC systems are the most basic form of converting AC power to DC. They rely on a series connection of several (typically three) so-called 12-pulse diode rectifier bridges, which are uncontrolled but offer advantages in terms of modular design, high reliability, reduced operation and maintenance costs. As the diode rectifier can be submerged in the insulating oil of the converter transformer, an offshore station based on a DRU results in a considerable reduction of mass and volume (Figure 38) compared to a VSC station, which in turn leads to a significant decrease in cost.

The DRU requires an AC grid, the frequency and voltage magnitude of which can be controlled. As a result, in case of an application to an OWF, the turbines in the OWF must be capable of creating an AC voltage together (i.e. be grid-forming[56]) which is controlled in order to control the power flow through the DRU into the DC link. The DC link voltage is thus determined by the OWFs. A FB converter capable of operating at low DC voltage is necessary on the other end in order to allow operation when one of the series-connected DRUs or connected OWFs is out of operation. DRUs are not capable of providing AC grid support and need filters to remove harmonic distortion.

Within PROMOTioN it is shown that DRUs can both be used for point-to-point connections of OWFs to shore and that they can also be used to connect an OWF to a DC grid. They cannot be used to connect the DC grid to the onshore AC grid. This is a result of the fact that the DRU is technically a rectifier and not a full converter and thus can only convert unidirectionally from AC to DC. Therefore, the DRU's application has its limitations. Using DRUs is not possible, for example, when providing energy exchange between countries through the offshore grid or when interconnecting OWFs. As the performance of DRU based technology has not been demonstrated, it was decided by the PROMOTioN consortium to only describe its use qualitatively and not take it into account in the Cost Benefit Analysis (CBA).

[56] This capability has not yet been proven by demonstration. In PROMOTioN this has been lifted to perhaps TRL 3-4.

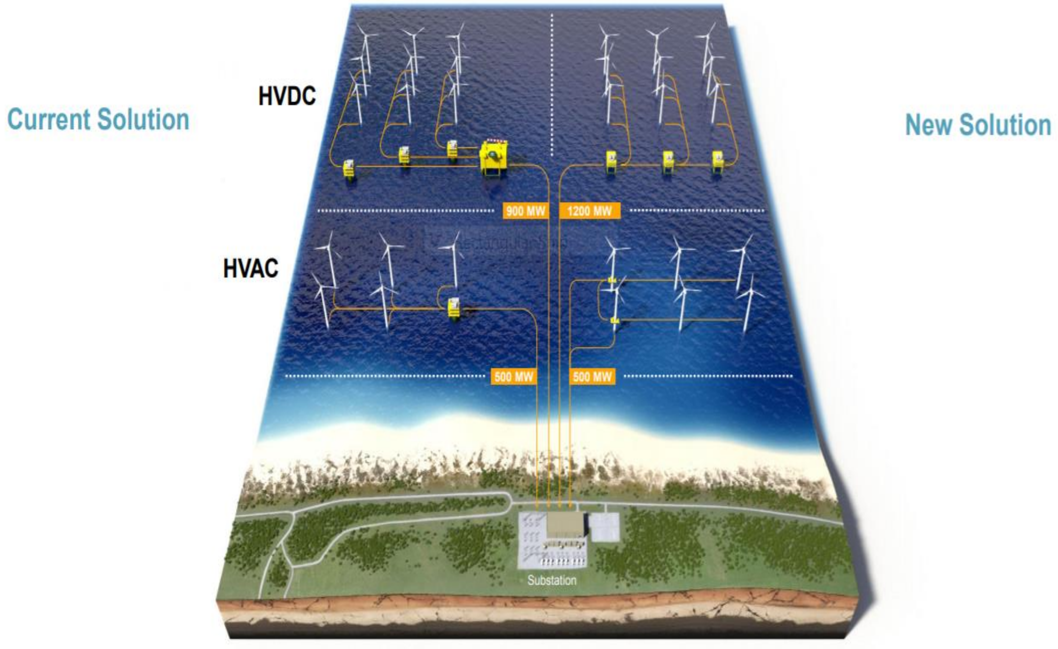


Figure 38 - Comparison of VSC and DRU connection

TRANSFORMERS

Transformers in OWFs can be considered as a link between OWFs and the grid. They are so-called passive components whose main role is to step up (boost) the medium voltage (MV) output from the OWF to the high or extra high voltage level of the transmission grid. In addition, transformers provide galvanic isolation between different parts of the electrical system, enabling local system earthing to control fault currents and neutral voltages. AC transformers are widely applied in on- and offshore systems, while several proposals exist for DC transformers, yet none are in operation today.

AC TRANSFORMERS

Within the PROMOTioN project each OWF is considered to produce power at medium voltage AC (66 kV), which will need to be transported to a platform or hub in order to be converted to DC. In early offshore HVDC projects, an intermediate AC transformer platform between the OWF and the converter station was needed to transform the OWF voltage to a voltage suitable for transmission to the HVDC converter station. Recent development in the offshore sector has seen the elimination of intermediate AC transformer platforms for short distances[57]. Any longer distance requires a higher voltage and thus intermediate AC transformer platforms to overcome the AC cable's resistance. These transformers are located on small platforms very close to or inside the OWF.

Every converter station also typically has a converter transformer to transform the grid or OWF voltage to a voltage suitable for conversion to DC, as well as to provide galvanic isolation between the AC and DC power systems. Depending on the converter technology and the converter configuration used, either a regular AC power transformer can be used, or the transformer needs to be specifically designed to be applicable to the converter.

AC transformers are passive components that do not require an active control system other than a tap changer and forced cooling control. The technology is very mature and thus considered to be robust and reliable. Due to their oil-immersed insulation, they have a relatively small footprint.

[57] This distance is suggested to be between 25 to 50 km. Within PROMOTioN, 25 km is considered.

DC TRANSFORMERS

DC transformers, or rather DC to DC converters, are active components that will be essential in stepping DC voltages up or down, but they may have many other functions. For instance, many DC to DC converters 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, energisation and start up, and integration of a wide range of existing DC systems. DC-DC converters have been widely used at low powers and industry applications, however they have not been applied at high and medium voltage transmission/distribution applications. In recent years there has been significant research on DC-DC technologies at manufacturers and in wider professional community, based on the latest advances in HVDC converters in particular related to MMC (Modular Multilevel Converter) technologies. It is accepted that high-power DC-DC are feasible and that they will follow DC voltage and power range of existing and future HVDC systems.

As DC to DC converters are active components, they require several control systems to successfully operate. Even though none are in operation today, several proposals exist mostly based on topologies similar to the MMC-VSC and thus consisting of many power electronics and capacitor based submodules. Due to their air-insulation they have a relatively large footprint. The technology is considered to be in its infancy and thus not yet reliable. They are therefore not further considered within PROMOTioN.

CIGRE has been very active in promoting and studying DC grid development in the last 10 years with at least 5 Working Groups (WGs) either completed or in progress. In 2009 SC B4 initiated WG B4-52 "HVDC Grid Feasibility Study", to investigate the feasibility of this concept. DC-DC are mentioned as important components in DC grids in several chapters. Two subsequent WGs have also discussed DC-DC:

- *B4-57: Guide for the development of models for HVDC converters in a HVDC grid*, considers some initial modelling options for DC-DC, and
- *B4-58: Load flow control and direct voltage control in a meshed HVDC Grid*, provides initial considerations for DC-DC for load flow control in DC lines and DC grid control.

In 2017 a new working group was established focusing solely on DC/DC converters:

- CIGRE B4.76 "DC-DC converters in HVDC Grids and for connections to HVDC systems".

The applications of DC-DC converters have been discussed and researched in academia, at systems operators and manufacturers. It is accepted that DC-DC will play an important role in DC grids although the exact functions, performance requirements and applications are not clear.

The DC collection systems for (offshore) wind farms are very actively studied and a range of new topologies have been proposed, e.g. solutions based on diode bridges. The ongoing work in CIGRE C6.31 will collect the state-of-art knowledge in developing MV DC systems, which will be used here to evaluate technology needs for interconnecting HV and MV DC systems.

Some studies have demonstrated that DC/DC converters may provide an attractive solution for tapping (tap is a load/source generally below *0.1 pu* power) on large HVDC systems. This application needs further evaluation by key industry players to understand the needs and most suitable technical options.

CIGRE B4.76 proposes that DC/DC technologies are grouped into two families:

- Isolated, dual active bridge DC/DC,
- Non-isolated, MMC based DC/DC

Isolated DC/DC will be able to provide galvanic isolation between DC systems which may be desired in particular in large DC grids [21]. They will consist of two MMC-based AC-DC converters (similar to those used with HVDC) and an additional transformer. They can perform full power control and DC fault isolation.

Non-isolated DC/DC are able to achieve direct conversion with a single MMC-type AC-DC converter and therefore their cost is expected to be much lower compared with isolated topologies [22, 23]. In general, non-isolated topologies will be used for lower stepping ratios (connecting DC grids of similar DC voltage levels), but they will be capable of bidirectional DC fault isolation (DC Circuit Breaker function) and full power control.

HVDC CABLES

HVDC cables are the key component in an offshore HVDC grid. Two basic types of cable technologies exist, which are differentiated by the material used for the insulation:

- Mass-impregnated paper insulation
- Extruded polymer insulation such as cross-linked polyethylene (XLPE) or P-Laser

Figure 39 - An HVDC cable

The main limitation of the offshore grid voltage level is determined by the maximum achievable voltage rating of cable technologies. The PROMOTioN project only considers large sized cables with extruded polymer insulation. Mass-impregnated cables are not taken into account since, as stated in Deliverable 2.1, cables with extruded polymer insulation are less expensive, lighter (which means longer lengths can be transported in cable vessels), have a higher maximum operating temperature and are more environmentally friendly compared to mass-impregnated cables. Many companies can furnish HVDC cables with extruded polymer insulation for nominal voltages up to 525 kV, with higher voltages up to 800 kV reported to be in development. Currently, a maximum continuous current rating of around 2 kA can realistically be achieved, which means a cable based 525 kV HVDC link can transport about 2 GW.

PROMOTioN considers cables with extruded polymer insulation 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 or current ratings, 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 the maximum allowable infeed loss.

SUBSTATIONS

Substations contain the equipment that is needed to realise nodes where cables or lines are connected to create a network. The function of substations is:

- To configure the grid topology, which can be done in multiple ways:
    - Online versus offline: can the reconfiguration be done whilst the substation equipment is energized or does it have to be de-energized first?
    - On-load versus off-load: can the reconfiguration be done whilst a current is flowing or does the current have to be brought to zero by external means first?
- To provide measurements, which can be done in multiple ways:

  - Online and offline: typically measurements necessary for the control and protection such as currents and voltages need to be done online. Other measurements, often related to condition assessment of primary equipment, such as partial discharge, insulation resistance, etc. can or needs to be done offline.
- To provide protection from over-voltages: to ensure that voltages at the substations do not exceed the insulation strength of the equipment, typically surge arrestors are placed at strategic locations, that almost instantaneously provide a low resistance path for excess energy in the system.
- To provide protection from over-currents (faults): over-currents can be protected against by HVDC circuit breakers.
- To control power flow: In very meshed HVDC grids, it can be difficult to control the loading of some cables by just adjusting the converter dispatch and additional circuitry like power flow controllers should be installed. These devices do not exist yet, but could be based on similar technology as MMC-VSC converters.
- To provide a grounding point. Two different aspects of grounding can be realized in a substation:
  - System grounding: System grounding refers to the reference potential used to define all voltages in an HVDC grid. The grid neutral point must therefore at all times be grounded at one point, but no more than one point to avoid DC currents in the ground. Hence, when grids are reconfigured, also the choice of grounding point can change and this can be realized by for example connecting the metallic return to a ground electrode by means of MVDC switchgear at a substation. In case of a loss of grounding elsewhere in the grid, an ultra-fast grounding switch may be used to protect the rest of the grid from potentially damaging overvoltages.
  - Safety grounding: the metallic sheaths of cables and enclosures of other primary equipment need to be grounded so that they are safe to touch and provide a defined (and safe) path for short-circuit currents. This is done at the substations.
- To act as transition point: substations provide an opportunity to connect lines or equipment with different insulation types of technologies.

In order to achieve these functions, the following components are commonly found in substations, in both AC and DC systems:

- Interfaces: wall bushings, cable terminations, cable sealing ends
- Busbars: single, double, ring
- Switchgear: Disconnecting switches, Earthing switches, Commutating switches, Pre-insertion resistors, Circuit breakers
- Instrumentation: voltage and current sensors, fault location detection
- Over-voltage protection: surge arrestors, choppers
- Earthing equipment: neutral zone equipment, earthing switches, earthing impedance, electrode

Substation systems are typically characterised by their insulation medium, of which the following two are available for application in offshore HVDC grids:

- Air insulated systems (AIS)
- Gas insulated systems (GIS)

AIR INSULATED SYSTEMS

In AIS the main circuit potential is insulated from ground or other conductors by air. This requires a significant clearance distance which, depending on the voltage level, is in the range of meters for HVDC. AIS contains such components like surge arrestors, circuit breakers, disconnecting switches (disconnectors), capacitors, busbars, etc. AIS is the most popular type of insulation and is applied in areas where space is not a limitation. Compared with the GIS, the biggest advantage of AIS is its simplicity, low cost, technology maturity and lower environmental impact.

GAS INSULATED SYSTEMS

GIS is smaller metal-encapsulated substation components comprising high-voltage components such as busbars, disconnectors and instrumentation. GIS is significantly smaller than air insulated switchgear, making it suitable to offshore platforms where space is limited. In GIS, the insulating gas is sulphur hexafluoride (SF_6), which has a global warming potential 23,500 times greater than carbon dioxide (over a 100 year period). Therefore, within PROMOTioN, WP15 is researching other gases with similar insulating properties that can replace SF_6.

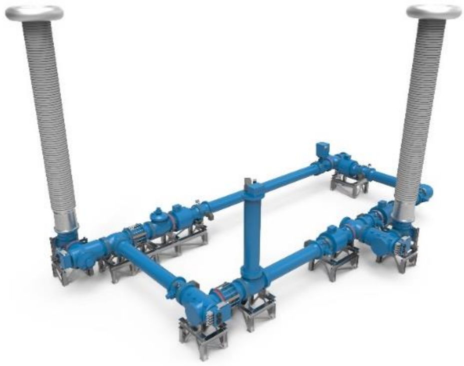


Figure 40 - 320 kV Gas insulated system demonstrated in PROMOTioN

BUSBARS

Busbars are the type of electrical junction where all the outgoing and incoming lines/cables are connected together and electrical currents meet. Typically, the lines are connected to the busbar system through circuit breakers and the isolators. In case of a fault, the circuit breaker is opened and the faulty section of the busbar is disconnected from the circuit. DC busbars are typically constructed in pairs because of the two poles, with, in the case of a bipole with dedicated metallic return (DMR), a neutral zone as well.

Different types of busbar and switchgear arrangements exist to achieve different levels of redundancy against busbar faults. The main types are:

- Single busbar – Single breaker
- Double busbar – Single breaker
- Double busbar – Breaker and a half
- Double busbar – Double breaker
- Ring busbar

SWITCHGEAR

Switchgear is used to control whether two circuits are galvanically connected or not by opening or closing mechanical contacts. Currents flowing through closed contacts cannot be stopped instantaneously when they are opened due to ever-present system inductance which will, as a result, form an arc between the contacts. Different types of switchgear exist which are distinguished by their ability to sustain such an arc and use the resulting arc voltage to either transfer the current to an electrical path parallel to the switch or to interrupt the current altogether. Furthermore, the speed of operation, achievable voltage ratings, and the so-called arc-quenching medium are differentiating factors.

There is a main difference between AC and DC switchgear in that AC current naturally goes through zero periodically and DC current does not. This means that DC switchgear typically requires external circuitry to reduce the current to zero before the contacts can be opened.

Three main classes of switchgear exist: disconnectors, high speed- or load switches and circuit breakers.

DISCONNECTORS

Disconnectors are switchgear which cannot interrupt any current whilst energized. They can be used to reconfigure the grid whilst it is de-energized, to earth unused parts of a circuit or to create visible breaks between circuits. They are cheap, and commercially available in both AIS and GIS implementation.

HIGH-SPEED SWITCHES

High-speed switches are switchgear capable of sustaining an arc resulting from a small current for a limited amount of time. They can be used to quickly reconfigure (de-energized and) unloaded parts of HVDC grids or if used in conjunction with pre-insertion resistors, also be used to energize HVDC cables or converter stations from the DC side. They are essentially AC circuit breakers made suitable for HVDC dielectric stress. They are predominantly available as AIS, although GIS development is underway.

CIRCUIT BREAKERS

The main role of the circuit breaker is to protect an electrical circuit from damage caused by short circuit or overload currents. Its basic principle is to operate immediately after detection of a fault condition by the protection system and then, by interrupting the current, to rapidly disconnect electrical flow. Interruption of AC current is fundamentally different from interruption of DC current.

AC circuit breakers

AC circuit breakers interrupt current by separating two conductor contacts and allowing an arc to form between them until the current naturally becomes zero due to its AC nature. At this moment, provided the contacts are sufficiently far away from each other, the arc extinguishes and the current has been interrupted. SF6 is commonly used as an insulating and/or quenching medium in high voltage AC circuit breakers, but due to its high greenhouse potential is gradually being replaced by SF6 alternatives. For medium voltage AC circuit breakers, a vacuum is often used as an arc quenching medium. AC circuit breaker technology is very mature and considered to be reliable. Operating times are several tens of millisecond. Due to the use of both insulating and arc quenching media, the footprint of AC circuit breakers is rather small. AC circuit breakers are currently used to protect HVDC links by disconnecting the entire converter station from the AC grid in case of a fault.

DC Circuit Breakers

DC circuit breakers require the use of additional circuitry to create a current zero locally to be able to open mechanical switches to interrupt the current and isolate. In addition, they require surge arrestors to absorb the magnetic energy stored in the system as a result of the DC current flow. This is shown in Figure 41 below. This additional circuitry is often air insulated and requires a relatively large footprint. HVDC circuit breakers have been developed by several manufactures, tested and several have been commissioned. Their maturity is considered to be sufficient for application, but their performance has yet to be proven through deployment. Within the PROMOTioN project three types of HVDC circuit breakers are considered; mechanical, hybrid and VSC Assisted Resonant Current (VARC) 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, 1.8 GW in the UK, 1.4 GW in Nordic countries and 0.7 GW in Ireland) or on nodes that could potentially propagate a failure leading to such a loss of power. Other applications in which DC circuit breakers improve the availability of a link or reduce the impact of a DC fault on the connected AC system can also be realized.

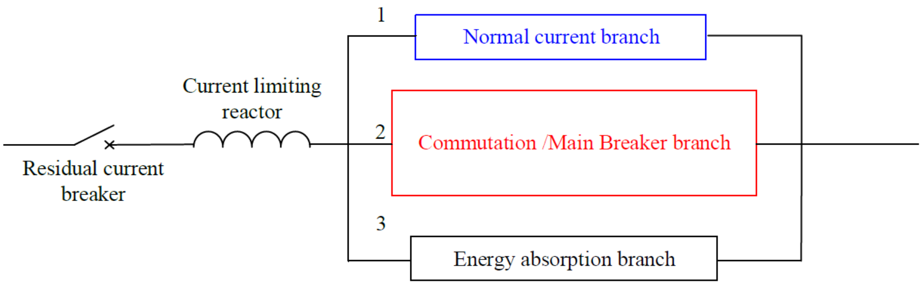


Figure 41– General topology of an HVDC circuit breaker

Mechanical DCCB

The main principle behind a mechanical DCCB is that it uses external circuitry to impose an oscillating current onto the DC short-circuit current to create artificial current zeros at which an AC circuit breaker can interrupt. The frequency of the oscillating current needs to be high in order to create a current zero fast enough to adhere to the high-speed clearing requirements for DCCBs. This results in high di/dt in the AC circuit breaker, which means that vacuum interrupters are preferred over SF6 based interrupters. Commercially available vacuum interrupter voltage rating is limited around 100 kV per bottle (even though prototypes up to 245 kV have been presented), limiting the voltage rating per module. Several interrupters or modules need to be connected in series to achieve realistic line voltage ratings. The use of mechanical interrupters means that relatively high short-circuit current magnitudes and current withstand ratings can be achieved. The increased contact mass however typically means mechanical DCCBs are typically slower (6-8 ms) compared to their electronic and hybrid counter parts. The reduced number of power electronic components (if any at all) means that mechanical HVDC circuit breakers also often substantially cheaper and more maintenance friendly. In some cases, they can be applied outdoor.

Two main types of mechanical HVDC circuit breakers are considered in PROMOTioN, the mechanical HVDC circuit breaker with active current injection, and the VARC mechanical HVDC circuit breaker.

A mechanical HVDC circuit breaker with active current injection, shown in Figure 42, creates current zero in the interrupter unit by discharging a charged capacitor in opposite direction to the DC fault current. A decaying high frequency AC current results, creating multiple AC current zeros in which the interrupter can interrupt. The current then flows into the injection capacitor Cp, charging it to the metal oxide surge arrestor (MOSA) protective level (transient interruption voltage), at which points the current commutates to the surge arrestor and is suppressed. The technology is inherently capable of interrupting currents in two directions. In order to achieve reclosing functionality, additional charged capacitors are likely to be required.

The VSC assisted resonant current (VARC) mechanical HVDC circuit breaker, shown in Figure 42, uses a small converter to excite a high frequency resonance current through the interrupter, growing to a magnitude higher than that of the DC short-circuit current and thereby creating current zeros for the interrupter to clear. The technology is inherently capable of interrupting currents in two directions, and also reclosing functionality is possible without additional circuitry except increased energy rating of the MOSAs. VARC circuit breakers can be quite fast around 2-3 ms breaker operation time.

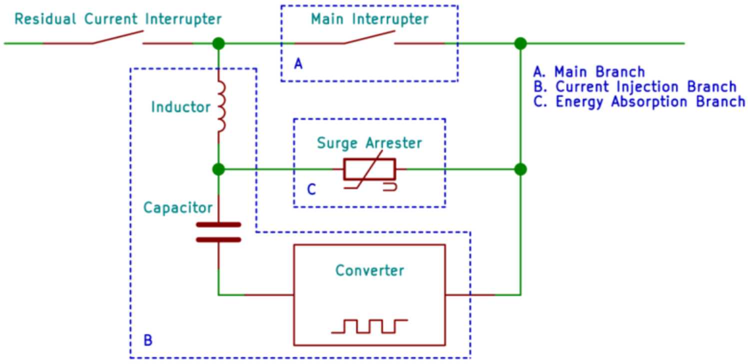


Figure 42 - General topology of a VARC mechanical HVDC circuit breaker module

Electronic DCCB

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

Hybrid DCCB

Hybrid HVDC circuit breakers, shown in Figure 43, use a mechanical ultra-fast disconnector (UFD), which is not capable of interrupting any current, in order to create a low loss normal current path. A small IGBT-based load commutation switch (LCS) is connected in series, capable of commutating the fault current into the parallel large IGBT-based main breaker branch. As soon as the current in the normal current branch is reduced to zero, the UFD can open and achieve its full insulation strength. At this point, the main breaker opens and commutates the fault current into the MOSA, to suppress it.

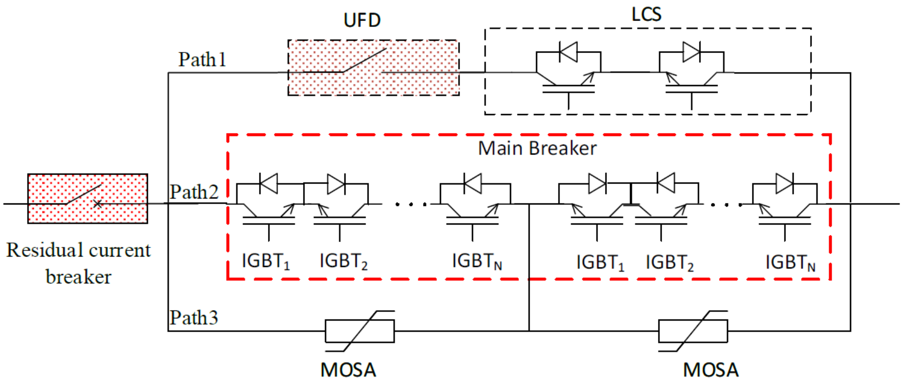


Figure 43 - General topology of a hybrid DCCB.

Due to the large amount of power electronics, the cost of the hybrid circuit breakers is quite high and if they were used on every interconnecting line, it would significantly increase the overall cost of the system. However, their reaction times are also fast (2-3 ms) which is beneficial in HVDC power transmission as converter blocking can be avoided during fault clearing. Hybrid HVDC circuit breakers can only be installed indoors, require a cooling system, and require regular maintenance to inspect for and replace any faulty IGBTs.

Electronic DCCB

Electronic HVDC circuit breakers are essentially the same as hybrid breakers without their normal current path. The normal current hence flows through the main breaker which causes high losses due to the IGBTs on-state voltage drop. Electronic HVDC circuit breakers are very fast however, interrupting HVDC fault current in a matter of tens of micro-seconds.

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.

INSTRUMENTATION

Measuring equipment and instrument transformers, are required as an input for the Intelligent Electronic Device (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.

SURGE ARRESTORS

Surge arrestors are non-linear resistors that are used to limit voltages. Below a rated protective voltage level, they exhibit very high resistance and can be considered as an open circuit. Above the protective voltage level (the knee-point voltage), the resistance of a surge arrestor suddenly drops, effectively providing a current path in which the excess energy in the system gets dissipated.

Surge arrestors are applied at any impedance boundary in power systems e.g. at cable terminals or next to transformers or reactors, in order to limit the voltages that these components experience. The balance between the protective voltage level, energy dissipation rating and the equipment's insulation strength is determined by an iterative process commonly referred to as insulation coordination.

Figure 44 - A surge arrestor module

Surge arrestors play a key role in HVDC circuit breakers in both providing a counter voltage which suppresses the fault current to zero and in the meantime dissipating the magnetic energy stored in the systems equivalent inductance.

Surge arrestors are made of the series and parallel connection of many metal-oxide (typically zinc-oxide) blocks to achieve the right voltage, current and energy ratings. Careful selection of the blocks is key to ensure balanced loading of the parallel columns. Surge arrestors are considered mature and robust components.

PRE-INSERTION RESISTORS

Pre-insertion resistors are used in conjunction with AC circuit breakers or high-speed switches in order to limit the inrush current when energizing converters or cables. The peak inrush current must be limited to protect equipment against the forces and thermal overloads which it can cause. To limit the inrush current, first the resistor is switched in series before by-passing it with a second switch to create the direct connection. Figure 45 below shows the states of operation. The open state is before energization. Then, the resistance is inserted by closing a first switch when energization is started, limiting the inrush current. Then, a second switch is closed to by-pass the resistor and start regular operation.

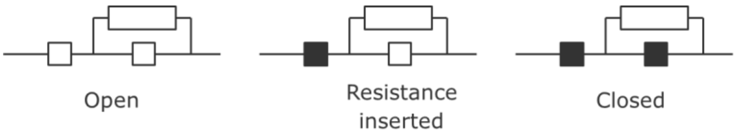


Figure 45- Pre-insertion resistor operational states.

FILTERS

Filters are used to remove unwanted current and voltage components to improve the power quality. These components could be harmonics, DC or zero-sequence components. Two types of filters generally exist: active and passive filters.

Passive filters operate by using a combination of passive circuit components such as inductors, capacitors and resistors to provide a low impedance return path and/or a high-impedance connection for the unwanted component. Typically, this is achieved by picking a resonance frequency of the filter components to provide low-pass, high-pass or band filter characterises. Passive filters are robust and mature, but are inflexible with regards to frequencies. Hence each unwanted component often requires its own filter.

Active power filters are power electronic components used to improve the power quality. The filter is connected in parallel with non-linear loads and inject a harmonic current into the grid that is equal to, but in opposite phase with, the harmonic current produced by the non-linear loads, hence making the total harmonic current approach zero and efficiently eliminating the effects of harmonics. Active filters are actively controlled and can hence filter a wide range of different unwanted components automatically, limited by the switching speed of the power electronic devices. VSC HVDC converters and STATCOMS can in principle be controlled to provide active filtering functionality, even though this has not yet found widespread use. The control of an active filter must be carefully tuned to avoid unwanted control interactions with other actively controlled devices.

DYNAMIC BREAKING SYSTEM S

Choppers are resistors controlled by power electronics which are used to dissipate the energy generated by HVDC connected OWFs in case of an AC-side grid outage. Choppers are typically an MMC arm in which the module capacitors have been replaced with resistors. The chopper is activated when the DC link voltage exceeds a certain level and provides a controllable resistive shunt path. The resistors are often water cooled to enable the absorption of the OWF energy. The energy absorption rating depends on the local grid code and the fault ride through requirements therein.

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. Phase shifters are essentially normal AC transformers with a particular winding arrangement which introduces a phase shift. 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.

SECONDARY EQUIPMENT

Secondary equipment are the devices which support and control the work of primary components. The secondary equipment considered in PROMOTioN includes Intelligent Electronic Devices (IEDs).

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 settings (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.

Figure 46- PROMOTioN HVDC Grid Protection IED.

SYSTEMS

The components described above can be configured to form HVDC systems. The way that converters are configured, earthed, controlled and protected defines the operational characteristics of such an HVDC system.

CONVERTER CONFIGURATION

The performance and operation of an offshore HVDC grid is to a large extent determined by the converter configuration. The following sections describe:

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

ASYMMETRIC MONOPOLE

An asymmetric monopole grid configuration operates with one HVDC cable and an MV return conductor grounded at one converter station. It is possible, and less costly, to realize an asymmetric monopole using a single HVDC cable with an earth return but this is prohibited in most North Seas countries due to negative environmental effects and potential damage to other infrastructure such as pipelines, cables or power distribution networks. Hence, this configuration is not further considered in PROMOTioN and the presence of a solidly earthed MV DMR cable is assumed as illustrated in Figure 47.

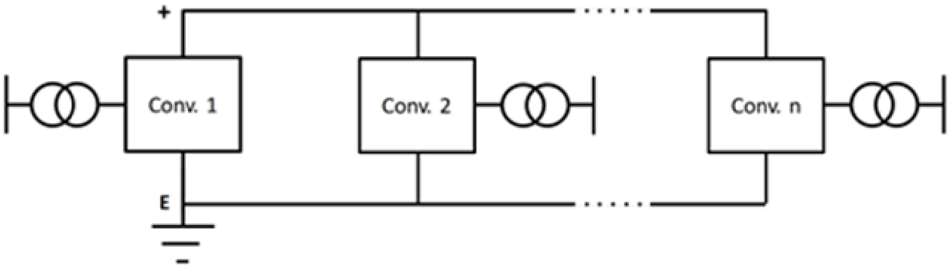


Figure 47 - Asymmetric monopole.

Due to its asymmetrical operation, the converter transformers experience DC stress and require a special design. Taking into account the same pole-to-ground voltage level and assuming the same current ratings, the transmission capacity is half of that of the symmetrical monopole described below. During DC earth faults, in case HB VSCs are used, a large fault current can flow which has an impact on the connected AC systems. Moreover, during a fault, the entire link capacity is lost.

SYMMETRICAL MONOPOLE

In a symmetrical monopole configuration, the DC side of converters is connected by two HVDC cables with a pole-to-ground voltage of the same magnitude but of opposite polarity as illustrated in Figure 48. This configuration provides double the power rating of an asymmetric monopole system with the same pole-to-ground 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 a symmetrical 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. However, during pole-to-ground fault, the earth fault current will be limited, and thus the impact on the AC grid is limited. The voltage of the healthy pole will however attempt to rise to double its rating, leading to excessive voltage stresses. The converter transformers used in symmetrical monopole MMC-VSCs are normal AC converters without any special considerations such as DC insulation strength.

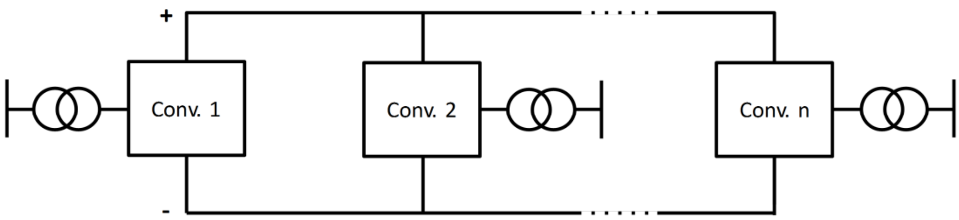


Figure 48- Symmetrical monopole.

Symmetrical monopoles have been used in the first generation of offshore HVDC connections to OWFs and the oil and gas platforms.

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 by a MV metallic return conductor as illustrated in Figure 49.

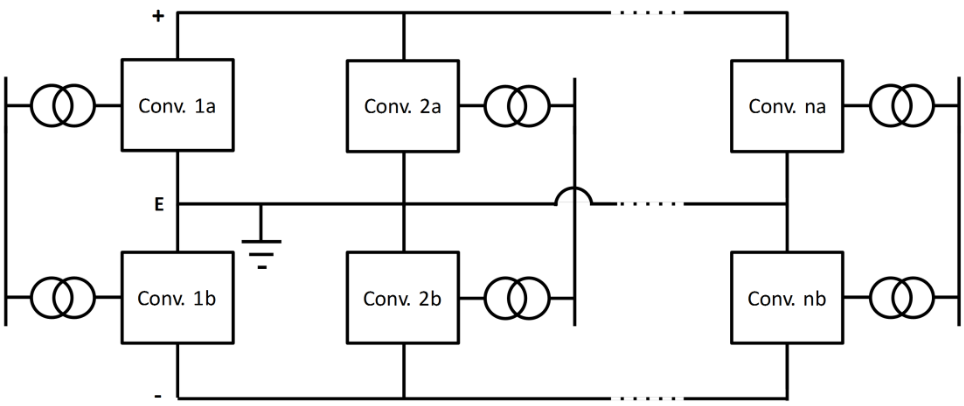


Figure 49– Bipole.

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 (halved) transmission capacity 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.

In OWF links with bipole converter configuration, separate OWFs can be separately connected to each of the bipole's poles, requiring a DMR to handle any mismatches/unbalance in generation between the OWFs.

MONOPOLE AND BIPOLE HYBRID

It is technically feasible to combine different converter configurations within the same multi-terminal HVDC system with asymmetric or symmetrical monopole configured branches tapping into bipole configured branches as shown in Figure 50. 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.

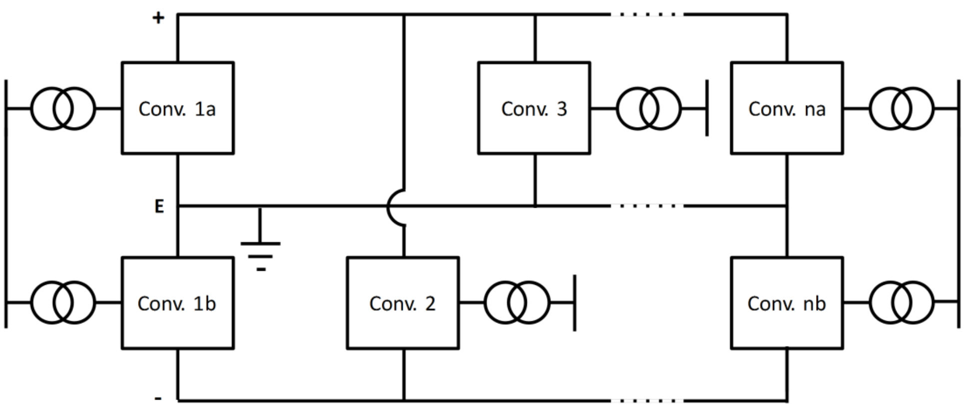
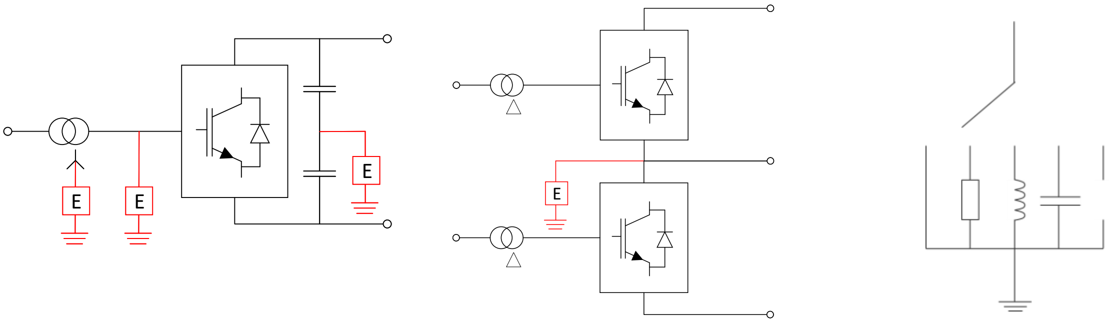


Figure 50 - Bipole configuration with asymmetric and symmetrical monopole tappings.

Therefore, in PROMOTioN these converter configuration options cannot to coexist in the grid. Instead the semi-flexibility and economic benefits of bipoles are used.

SYSTEM EARTHING

As in AC systems, DC systems need to have a system earth as reference and to avoid excessive line-earth voltages. System earthing 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. It also provides a path for a flow of current that will allow detection of an undesirable connection between system conductors and ground e.g. a fault. Typically, a DC system is earthed at one point only, to avoid (DC) earth currents. In a symmetrical monopole configuration, this earthing is typically realized at the converter station. Several earthing methods exist, as shown in Figure 51 below, and are typically converter vendor specific. In addition, in a trade-off between fault current magnitude and overvoltage magnitude during line-earth faults, different earthing impedances can be chosen, as shown below in Figure 51c. It is possible to have different earthing impedances at one earthing location, selected by a switch at that location.



a) Earthing locations in a symmetrical monopole

b) Earthing locations in a bipole

c) Earthing impedances

Figure 51- System earthing options.

CONTROL SYSTEMS

In addition to the controllers of the individual components within the HVDC system (e.g. converter controllers), a system wide controller is needed to enable stable operation under all foreseeable operational scenarios. The “central grid controller” for HVDC systems defines the load flow by setting the control modes and corresponding set points – of the converter controllers. These control modes and set points, e.g. power or droop values will not be hardcoded into the converters, as that would result in a loss of flexibility. This requires corresponding communication of measurement signals and modes between a central controller and the converters.

For existing point-to-point systems connecting OWF to shore, this adaptive setting might only be regularly changed for the AC side reactive power set points in normal operation. However, even for point-to-point systems embedded into the AC onshore grid, a “central” control on the system would be needed for the DC side load flow. Today, the links are or will be controlled by the existing AC system control rooms.

The operational routines and set points for a DC grid are different from an AC grid, so for the HVDC grid new functions are needed in the “central grid controller”:

- Setting of control modes and set points for normal operation –based on the availability of the installed grid components and different objectives (e.g. lowest losses in the DC or combined AC/DC system)
- Setting of controls for infeed changes, e.g. due to wind fluctuations or OWF shut down
- Setting of controls for emergency operation – e.g. certain fault clearing strategies need a central controller in the DC system to work, e.g. a full-bridge MMC based fault clearing strategy
- Setting of controls for ancillary services on the AC side, e.g. frequency support

The governance of such a central HVDC grid controller (i.e. who owns and operates it) remains a challenge.

PROTECTION SYSTEMS

Protection systems are a mix of circuit breakers, electrical disconnect switches or fault-blocking converters. This type of equipment is required for the security of the offshore grid. Protection systems are 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.

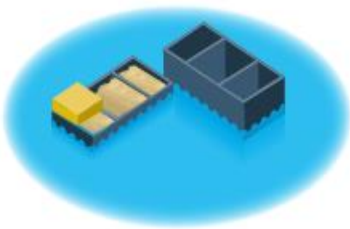
SUPPORT STRUCTURES

PLATFORMS

Platforms are built as supporting structures for VSC converters and other devices within a substation e.g. transformers. Depending on the topside weight, size and water depth, different types of support structures exist, examples are shown in Figure 52. Their cost is very significant in offshore projects and scales up almost linearly with the size, therefore alternative solutions like artificial islands are being investigated for large scale offshore installations.

a) Gravity based floating structure

b) Fixed structure Jacket – installation

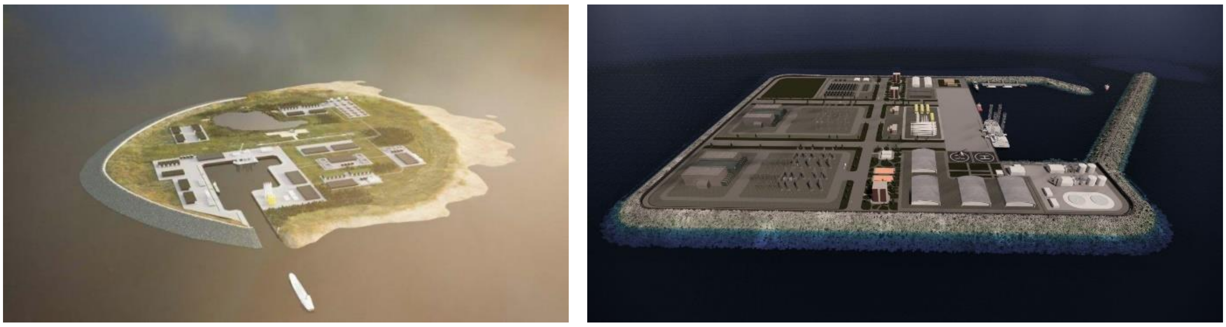


c) Caisson island structure

Figure 52- Different type of platform support structures.

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) and/or storage facilities. Artificial islands have not yet been constructed in the North Seas but are promoted by the NSWPH consortium and have been 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. Two artificial island impressions are shown in Figure 53 below.



a) North Sea Wind Power Hub artificial island impression

b) Offshore Service Facilities

Figure 53- Different artificial island options.

APPENDIX III – 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 54).

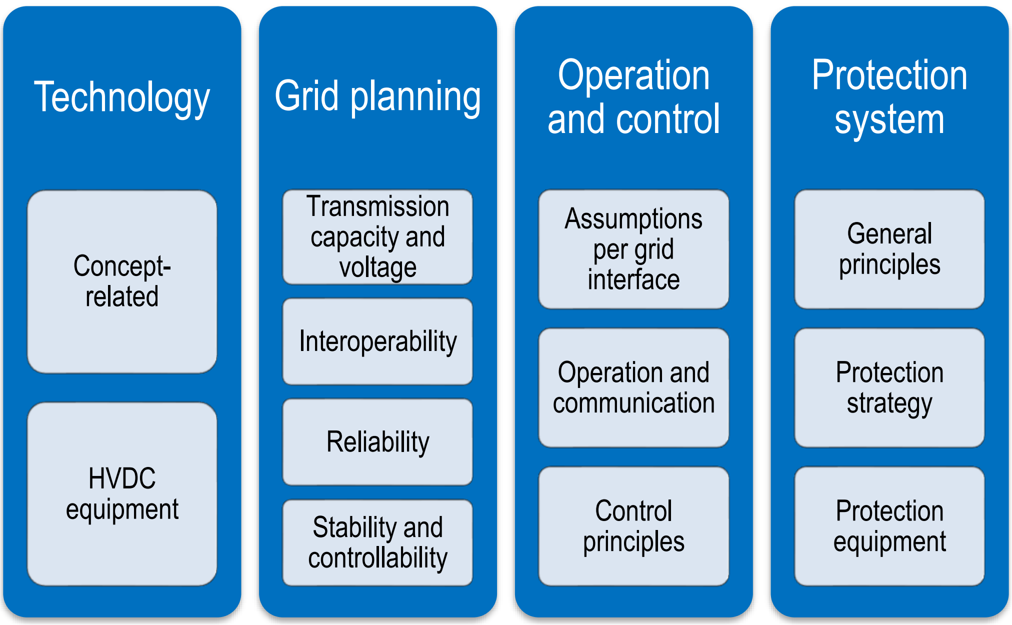


Figure 54- Technical categories

- 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 hubs 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 hubs with 150 kV AC cables, requiring an additional offshore collector platform. OWFs that are over 100 km away from the hub would have to be connected through DC cables, requiring an offshore converter.

Monopolar or bipolar

- All grids are assumed to be connected in bipolar converter configuration. For radial connections, asymmetric monopoles are allowed.
- A bipole with dedicated metallic return (DMR) is used, as opposed to a rigid bipole, or earth return, as DC earth currents are prohibited in some countries and faces environmental objections in others. Using a bipole with DMR, improved redundancy can be realized as well as unbalanced loading of the poles, which is necessary when connecting asymmetric monopole radial connections to the grid

Converters

- Line-commutated converter (LCC) technology is out of scope of the PROMOTioN project. The focus is on modular multi-level (MMC) VSC converters and DRU technology.
- Diode Rectifier Units can in principle be used to radially connect OWFs to meshed HVDC grids. However, as the development of DRU technology in PROMOTioN was discontinued, DRUs are not taken into account quantitatively in the CBA. DRUs may offer cost savings due to reduced size and weight and could therefore be an interesting future option. DRU technology could be available in the near future if a sufficient market need is realized and governance issues can be solved.
- HVAC circuits might be used in parallel with particular HVDC circuits but operating at lower voltages, primarily for the purpose of providing auxiliary power to HVDC converter platforms and OWFs. 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 offshore substation is only considered for AC cables over 50 km (see 'Cables' above). AC transformers are also required at each converter station to step up or down the voltage and provide galvanic isolation.

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 (i.e. when the OWF distance from a hub is over 50 km).

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 point-to-point, depending on the power rating, onshore grid constraints and required availability, different converter configurations are preferred in different situations. 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 export connection and interconnection.

EUROPEAN CENTRALISED

Cables

- As the connections are mainly point-to-point, monopole configurations are dominant. However, bipolar converter configurations are considered in some circumstances such as the connection between islands.
- Islands are interconnected through DC cables.
- Hybrid assets are considered for both wind farm connections and interconnection.

Islands

- Islands are considered only in this concept.
- The allowed size of the island hub, as described in Deliverable 12.1, ranges from 4 GW to 35 GW.
- Hubs can be AC type or DC 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, circuit breakers, 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 components and their ratings was given in Deliverable 2.1 and is not presented here. For each technology, specific characteristics (such as TRL) are described.

CABLES

Characteristic	Options	Comments
TRL (Technology Readiness Level)	• 66 kV (AC) • 150 kV (AC) • 320 kV (DC) • 525 kV (DC)	• 9 • 9 • 9 • 8, however TRL is assumed to be high enough to be used in the near future.
Voltage	• 66 kV • 150 kV • 320 kV • 525 kV	• OWF (inter array): 66 kV • OWF to hub (< 50 km): 66 kV ○ Note that higher inter array voltages up to 132 kV are being considered. • 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	• Single core • Dual core • Hybrid, (can be used with DRU)	• Conventional single core cables consist of two DC cables separately and one umbilical separately. They can be bundled in one trench. • Dual core or coaxial cables combine both poles or a pole and metallic return in one cable. This design is unlikely to be applied in future projects • Hybrid cables are designed to provide a means of supplying auxiliary power to offshore platforms and OWFs because VSC converters cannot do so. Hybrid cables consist of two DC cores and AC umbilical combined in one cable.
Insulation	• Extruded polymer • Mass impregnated paper	• Cables with extruded polymer insulation such as XLPE are the preferred choice, as they are cheaper, lighter and easier to handle than mass-impregnated cables. (Deliverable 2.1) • Cables with mass impregnated paper insulation are no longer allowed offshore in some sectors due to their oil content.
Power capacity (per circuit)	• 700 MW • 900 MW • 1.0 GW • 1.2 GW • 1.4 GW • 1.6 GW • 2.0 GW	• Currently, the maximum ampacity of submarine cables is considered to be 2 kA per conductor. A 500 kV bipole can hence transport 2 GW of power • Power capacity dependent on the capacity of connected OWFs and voltage level.
Umbilical cable		• In hybrid cables, these are 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 vary 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.

Voltage Source Converters

Characteristic	Options	Comments
TRL	• Half Bridge (HB) • Full Bridge (FB)	• Half Bridge: 8 or 9 depending on voltage level. • Full Bridge: 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. • Due to the two additional IGBTs, FB submodules can also generate negative voltages. • 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 or non-selective fault clearing strategy). The additional IGBTs in FB converters lead to higher cost, high losses, and higher forced energy unavailability (failure rate)
Voltage (AC and DC)	• 320 kV • 525 kV	• 320 kV considered in the 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 mainly depends on the maximum allowable loss of infeed.
Availability		• Whether higher rating converters are assumed to become available later.
Losses	• 0.8 % at full load	• At full load for half-bridge converters. No load losses are around 0.1% • Single percentages are used for simplicity even though it is recognized that the losses vary pre-dominantly as a quadratic with converter loading. Only half-bridge converters are considered, losses of full-bridge converters are likely to be higher due to the larger number of semi-conductors
Mean time to failure	• 6,257 hours	
Mean time to repair	• 6 hours	Also known as Forced Energy Unavailability.
Scheduled energy unavailability	• 7 days / 2 years	Downtime for regular maintenance activities

Diode Rectifying Unit (DRU)

Criteria	Options	Comments
TRL		• 5
Type of connection	• Radial OWF to shore • OWF to single hub • OWF feeding into an interconnector (T-	• Depending whether or not DRUs can be used in other than OWF-shore connections, the overall cost of the network will change significantly.

Criteria	Options	Comments
	connected)	
Platforms	• Few units on one platform • Large number of small platforms	• The volume of the platform structures is reduced by 20 % in comparison to existing VSC platforms. • The weight of platforms is reduced by 45 % in comparison to existing VSC platforms. • Two DRU modules installed per platform. • Typical 1200 MW OWF connection consists of three offshore platforms.
Type of start-up voltage source which accompanies the OWFs	• MV Umbilical AC cable • Diesel generator	
Voltage	• Rated AC Offshore Grid Voltage (L-L): 66 kV • Rated DC Voltage (U_{DC}) 320 kV.	• The collector grid of each OWF was operated at medium AC voltage (66 kV). • DRU modules will be connected in series to provide the HV 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 contains DC switchgear and a 12-pulse diode rectifier arrangement.
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
Control implications		• Voltage and power flow control requirements are transferred to OWF and onshore converters. This creates a governance issue
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 66 kV to 150 kV.
Power	• 250 MVA • 300 MVA	• 250 MVA for voltages 150/66 kV • 300 MVA 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 for DCCBs by splitting the system during operation • Considering each onshore bus to be composed of a single bar would be unrealistic and it will substantially increase the number of DCCBs required (selective vs non-selective clearing).

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 -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.
Mean time to failure	• 870,000 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 additional DC switchgear bay and cable landing.
Capacity of island (depending on the depth)	• >4 GW and potentially up to around 35 GW	• It may be assumed that island capacity can be fitted according to the requirement.
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 on mass of the components.
Platform	• Jacket type	• Platforms are required as a supporting structure for converters. • Converters have high mass and volume, big area requirements. • Platforms very close to the park (minimizing the length of the 66 kV 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 < 40 m • Platform < 45 m	• Island construction has a large impact on a seabed.
Cost	• Platform scales linearly with size	

	• Island constant cost	
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.
Decommissioning	• Platform can be lifted and disassembled onshore • Decommissioning the Island is unknown	

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. The 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. In addition, some offshore load can be foreseen in the future such as power from shore for oil & gas installations. This factor has not been taken into account in the analysis.

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 15), 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 15 - 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[58], 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.
- Overplanting in OWFs is not considered in the grid planning
- 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 trading within countries, trading between 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 drops of converter controller have stabilised the system) and they should go back to normal (continuous) operating limits after system adjustments.

For the PROMOTioN project reliability is assumed to be ensured by connecting cables to shore of the same value (or lower) 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.

[58] 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.

- 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 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 the 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 – 320 kV and 525 kV, where the former is used mainly for point-to-point connections with the transfer of power up to 1 GW and the latter is used for the transfer of power up to 3 GW, as is shown in Figure 55. 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.

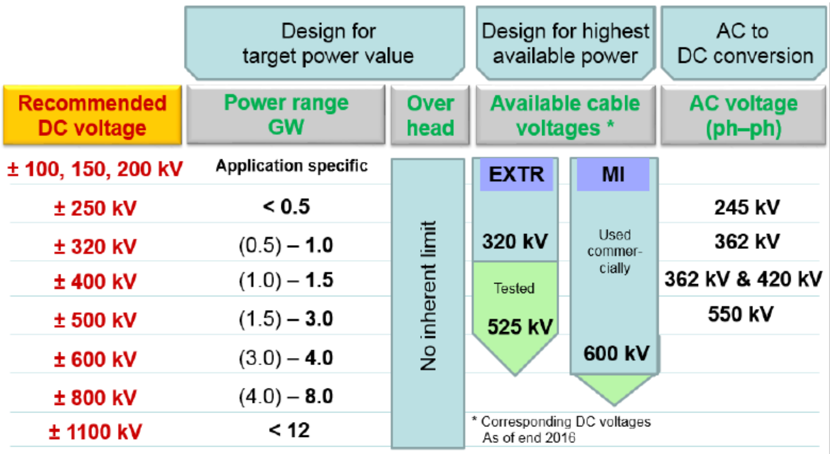


Figure 55- Recommended DC voltage level and possible DC power transfer range [18]

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 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 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, greatly improving the link availability.

Characteristic	Options	Comments
Monopolar or bipolar	• Asymmetrical monopole • Symmetrical monopole	• Asymmetrical – one HV cable and return, one converter: no redundancy. • Symmetrical – two HV cables, one converter: no redundancy. Double the power transfer of asymmetrical monopole with same rated pole voltage and rated

	• Bipole	current. • Bipole – two HV cables and return, two converters (of half power of symmetrical), same power as symmetrical, higher redundancy due to monopole operation capabilities. Lower loss of infeed impact compared to monopole configurations
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 are then more difficult to apply. 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 0-2 pu voltage on the healthy pole. • DC surge arresters and pole re-balancing equipment 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 grounded 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. • Only one earthing point should be present in a DC grid at any point in time

OPERATION AND CONTROL

This section focuses 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 (PROMOTioN - Deliverable 1.1):

- 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.

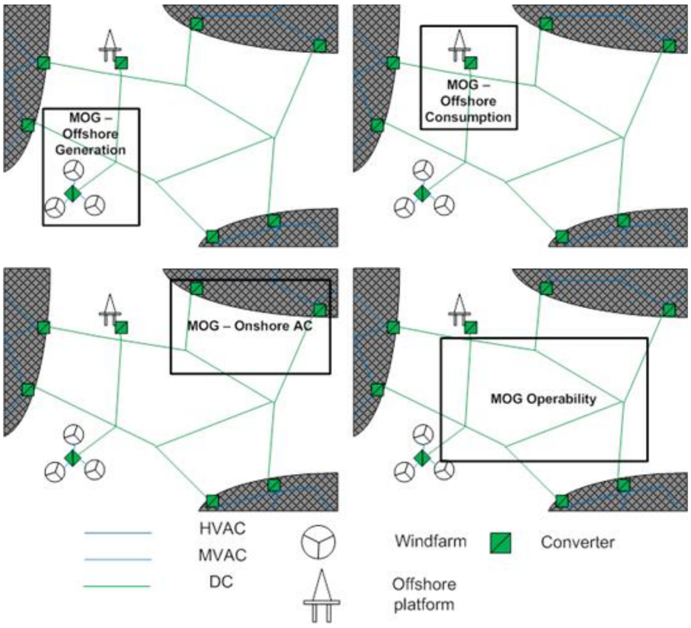


Figure 56 - Grid Operation Interfaces

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 16- 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 [24].
    - 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 600 MW/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 15.

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 17)

Table 17 - 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 [25]. ROCOF ranges specified in Figure 57 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.

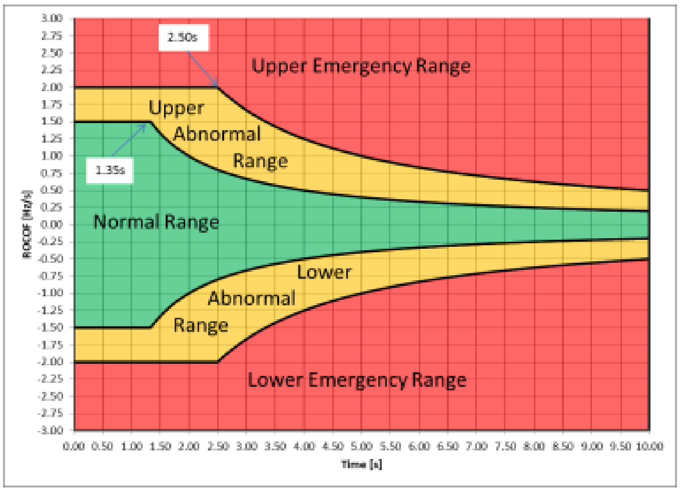


Figure 57- ROCOF Ranges

- **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[59] or asymmetrical[60] 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.

[59] 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.
[60] 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

These offshore loads usually have a lower power rating (20-300 MW) than those of the OWFs, which range from 600 MW up to over 1000 MW. 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 Power Oscillating Damping (POD) 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.
- 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 onshore 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[61].
- 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)[62]. 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 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.

[61] 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.

[62] 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 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 oversized nor too poorly designed.
- Requirements connected to multi-vendor protection of DC grid:
    - The DC grid protection should be designed such 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 power ramping rate		• Germany, an upper ramp rate limit of 10% of grid 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 rate of rise in the current 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 15). 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.

DCCB

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 OWFs.
Type	• Hybrid • Mechanical • Unidirectional • Bidirectional	• If only hybrid DCCBs are technically applicable for the power levels and voltage present in the offshore grid, only OWFs 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 100 kV. • 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 are much bigger than mechanical ones. • 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	• 160,000 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	• 160,000 hours	
Mean time to repair	• 6 hours	

HVDC GIS

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. (100 mH used with 2 ms and 150 with 8 ms)
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 cascaded sub-modules	• 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.
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/ thyristor 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 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 point-to-point 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 600 MW up to 2000 MW. 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 consider 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[63]. 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 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.

TECHNOLOGY DEVELOPMENT

PROMOTioN uses currently available costs for commercial or near-to-market HVDC assets and assumes a certain cost reduction for these technologies 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 and significant improvements to the technologies.

[63] 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.

APPENDIX IV - 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:

- EU Institutions, Agencies & Councils
  - DG Energy North Sea Energy Forum
- North Sea Wide Institutions
  - North Sea Countries' Offshore Grid Initiative (NSCOGI)
  - Conference of Peripheral Maritime Regions (CPMR)
- Non-Sectoral Organisations with Energy Interests
  - North Sea Marine Cluster (NSMC)
  - OSPAR Commission, in particular the committee for "Environmental impacts of Human Activities."
  - 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".
  - Interreg North Sea Region Programme (Interreg/NorthSEE)
- Energy Trade Bodies.
  - ENTSO-E
  - Ocean Energy Europe
  - WindEurope
- Governments / Member States
  - Ministries responsible
- National and Supranational Regulators
  - ACER
- TSOs
- OFTOs
- Wind Farm Developers
- Investors, including the European Investment Bank (EIB) and the Connecting Europe Facility (CEF)
- Manufacturers & Contractors.
- Testing & Certification Agencies
- NGOs (Environmental, and other related)
- Interconnector Owners (e.g. BritNed)
- 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 [26]. 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.

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 [27] 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 liberalise 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
- 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. Ocean Energy Europe's work involves engaging with the European Institutions (Commission, Parliament, Council, European Investment Bank, 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.

GOVERNMENT 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 up to six ministries sit at the table for negotiations.

AGENCY FOR THE COOPERATION OF ENERGY REGULATORS

ACER 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.

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 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 58 below summarises the TSOs in the Northern seas region:

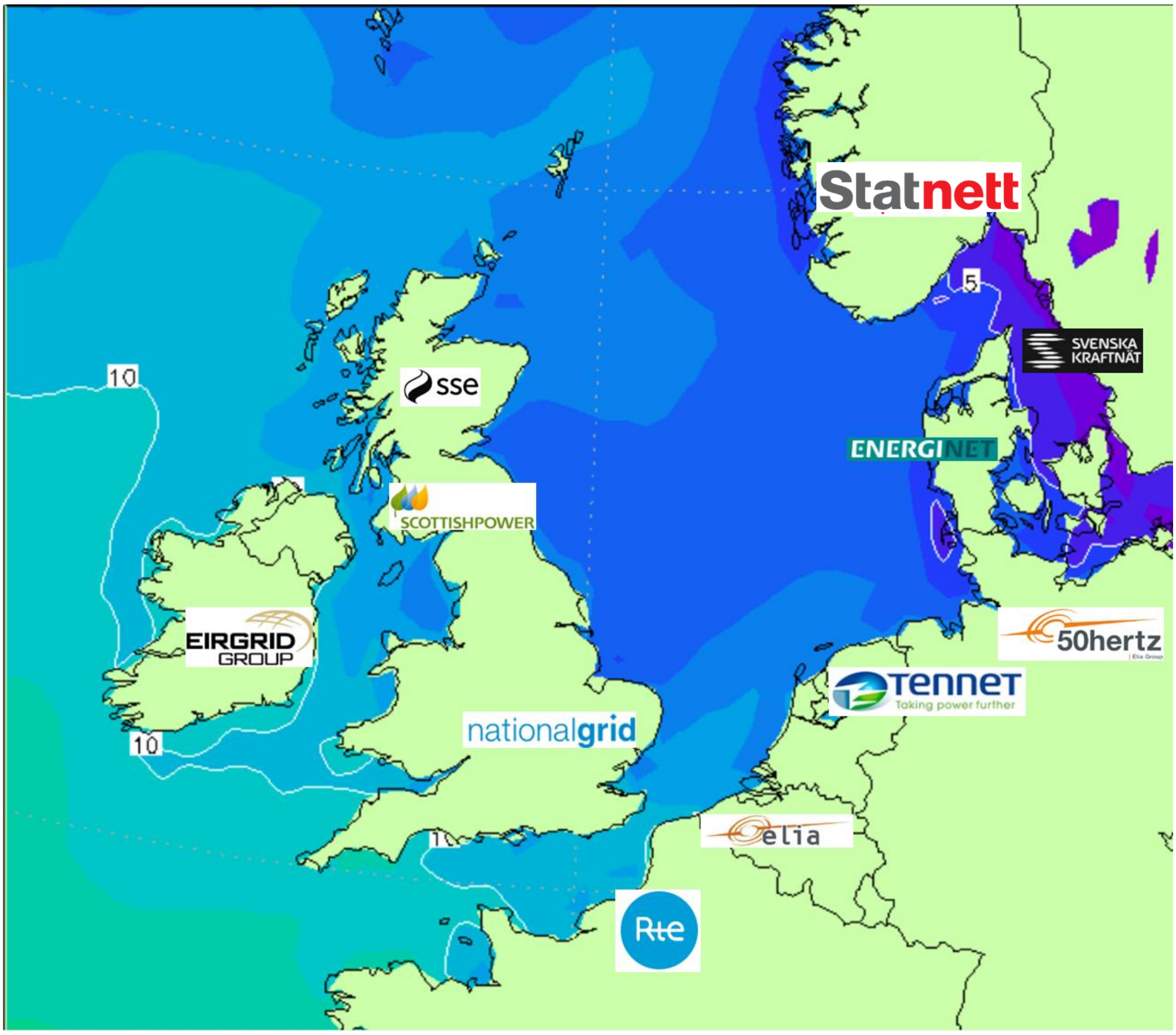


Figure 58- Map of North Seas TSOs

1. 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.
2. France has a state owned TSO, RTE.
3. The Netherlands has a state owned corporate TSO, TenneT TSO. TenneT is the owner of TenneT Germany.
4. 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
5. 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.

6. Denmark has a state-owned TSO, Energinet. There is talk of opening the offshore market to OWFs to construct their own infrastructure.
7. 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.
8. Sweden has Svenska Kraftnät (SvK) which is state owned TSO.
9. 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) and SvK (Sweden) are all members of the PROMOTioN consortium.

OFFSHORE TRANSMISSION OWNER (OFTO)

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 varies 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 point-to-point 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.

TESTING, INSPECTION AND CERTIFICATION AGENCIES

Testing, inspection and certification agencies (TICs) are stakeholders as all installations will need appropriate approval. We should be aware that the HVDC industry is nascent. 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 ORGANSIATIONS (NGOS)

NGOs seek a balance in the use of and protection of the North Sea. Their interests vary, but often include spatial planning 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. Stiftung Offshore Wind 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, Katholiek 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.

APPENDIX V – OFFSHORE WIND MARKET STRUCTURES

Report by TU Delft

INTRODUCTION

In this appendix, we will provide a more in-depth analysis of the market designs for an offshore grid that were proposed in Section 4.3. We will base our analysis again on numerical examples, but this time the example set-up is chosen so as to demonstrate all possible cases. As a consequence, the examples in this appendix are not realistic.

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 Exclusive Economic Zone (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[64]. 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 the conclusions, 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 rather here we will focus on a market design that is economically efficient and feasible in the European legal context.

[64] 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).

The remainder of this document is organised as follows: The Section on assumptions describes the theory and assumptions that underpin our analysis. In the Section, *Possible market designs,* we develop a number of options for pricing offshore wind energy. In the Section *Numerical examples*, simple numerical examples are used to compare these options. The Section on comparison and evaluation provides a comparison and an analysis, which also touches upon investment, renewable energy policy and the relation with other energy carriers. The concluding Section summarises the conclusions of the analysis and reviews the juridical implications of the analysis.

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 the following Section 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.[65]

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

[65] 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 costlier and more polluting quick-start units.

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 (flow-based) 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 re-dispatching of generation units by the TSO. 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.

We assume that the capacity of the wind parks is larger than the capacity of the network, i.e. that ‘overplanting’ has occurred. A certain degree of overplanting is economically efficient because it allows for a higher energy output, relative to the available network capacity, at moments of low wind and when some of the wind parks are in maintenance or still under construction. Without overplanting, the network would rarely, if ever, be used at its full capacity, which would mean that an opportunity to produce more wind energy without having to invest in more network capacity would be forfeited.

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 in the following Section are developed to illuminate these welfare distribution aspects.

POSSIBLE MARKET DESIGNS

We identified three 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 Exclusive Economic Zones of the North Sea countries. This means that wind parks receive the electricity price of onshore price zone in which they are located.[66] 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.

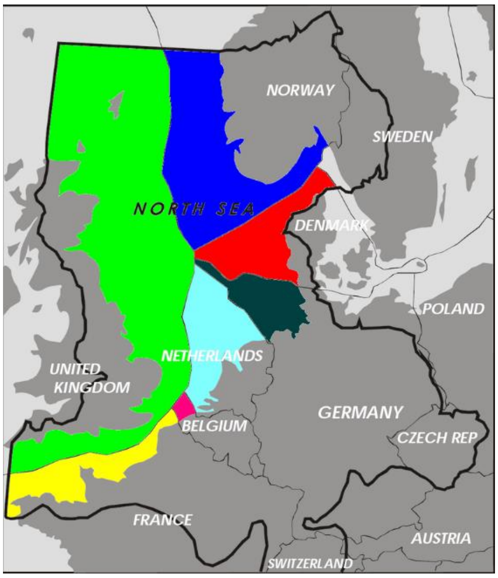


Figure 59 - North Sea Economic Zones. (Source: https://en.wikipedia.org/wiki/File:North_sea_eez.PNG)

- **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

EXAMPLE SETUP

We will now introduce the numerical example which we will use to demonstrate the above three 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 60. If it produces a full capacity, its output needs to be split between the two countries.

[66] 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.

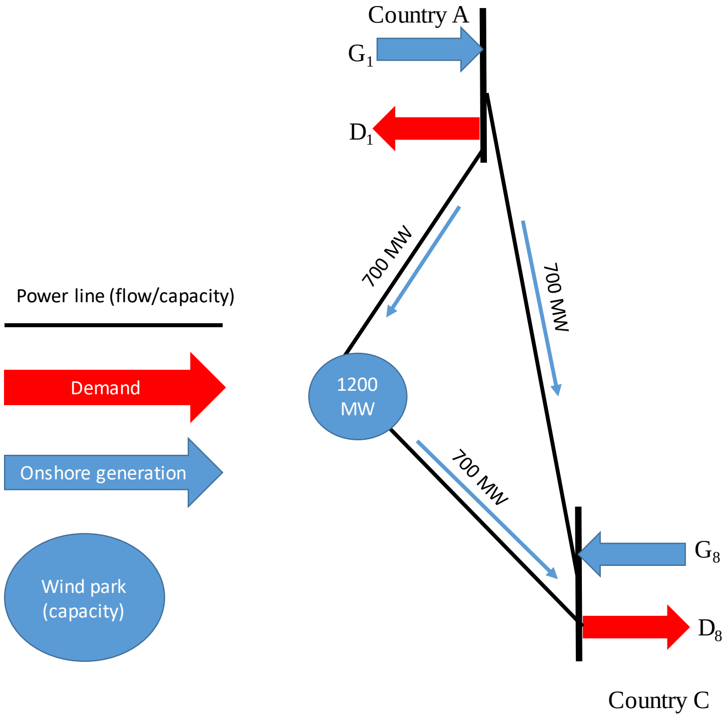


Figure 60 - Example set-up: wind park connected to two countries.

The second part of the example consists of a string of wind parks which exists in parallel to an interconnector between Countries A and B, as shown in Figure 61. 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.

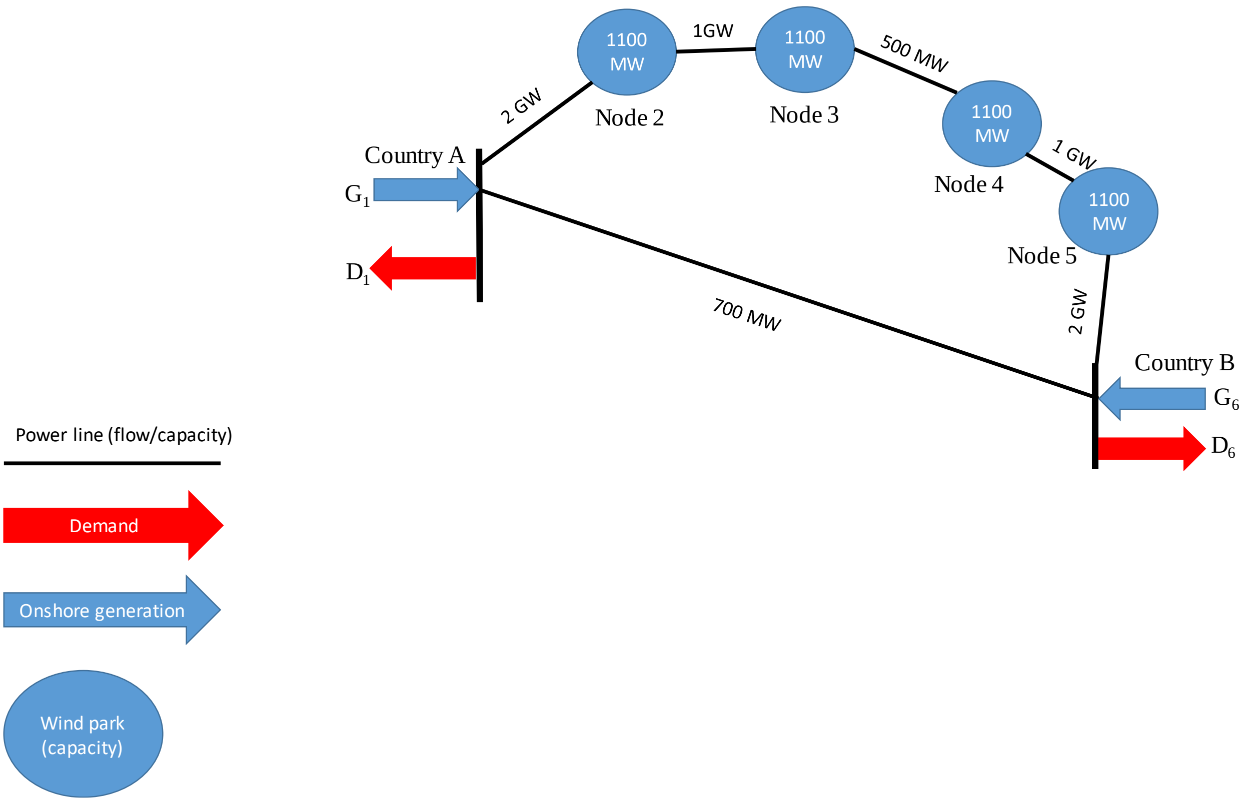


Figure 61- Example set-up: series of wind parks between countries A and B.

Combining Figures Figure 60 and Figure 61, we arrive at the system that is depicted in Figure 62 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 62. We label all nodes in our examples, because they are grouped differently in the different market designs. In Figure 62, 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 62 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.

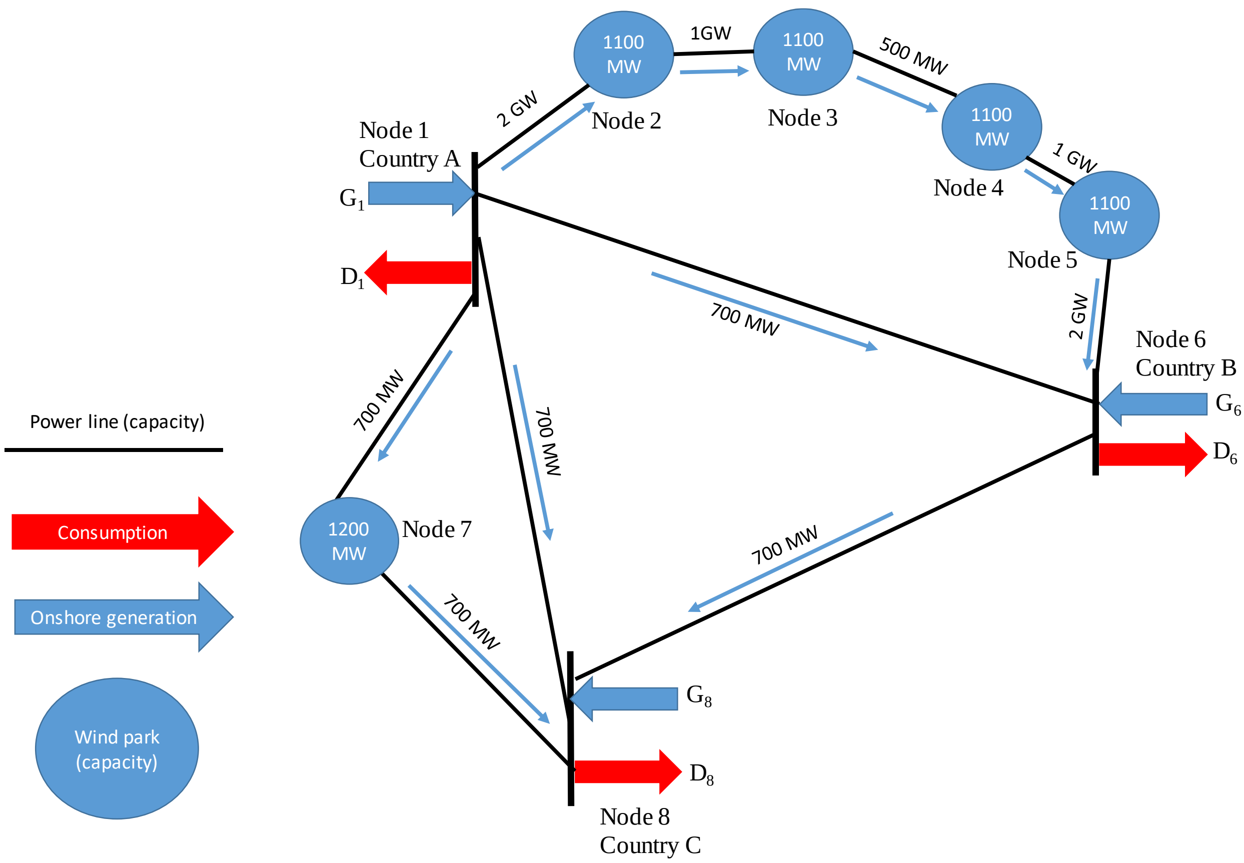


Figure 62- Example set-up.

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 63 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. Presumably, the curtailment rules of the Electricity Regulation (Article 13(7)) apply and full cost compensation is required. This might lead to an incentive for over-dimensioning wind parks more than the optimum that we discussed above.

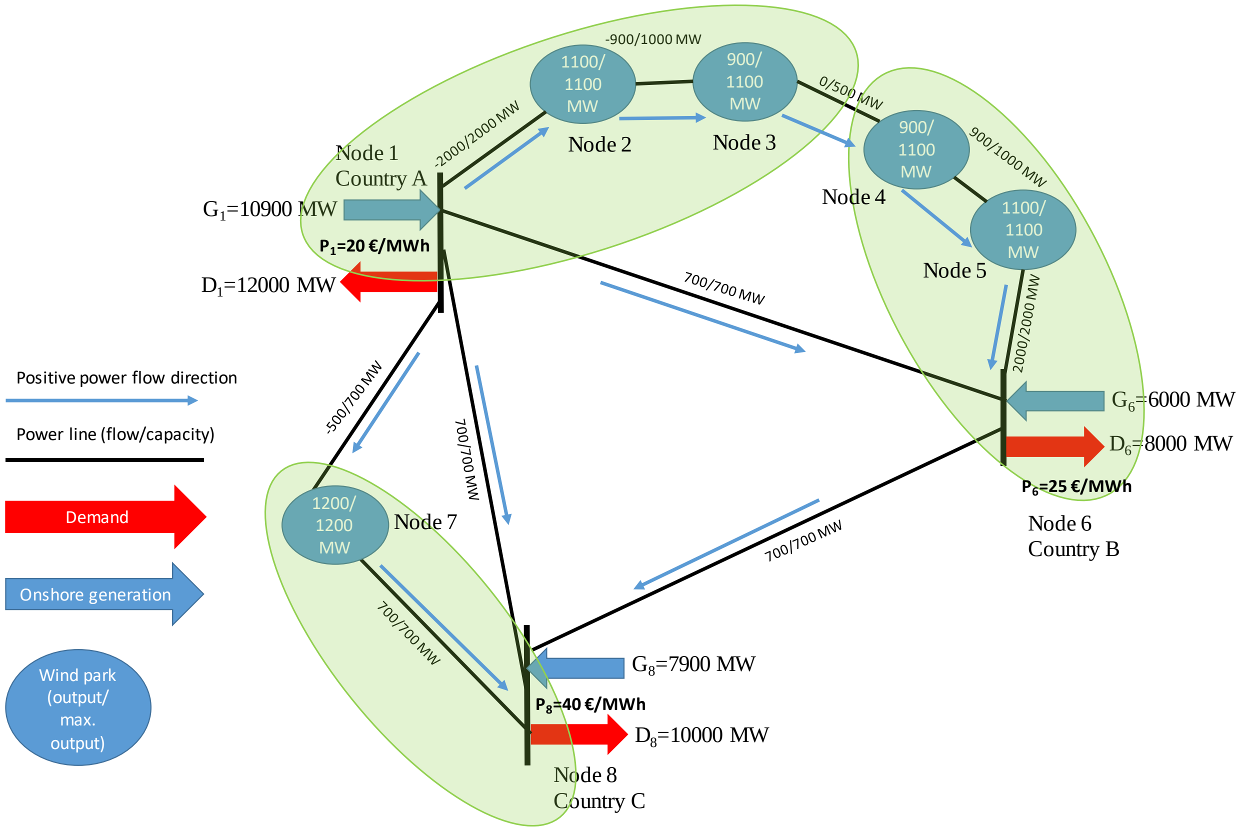


Figure 63 - Wind parks part of national price zones, high wind.

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 63. 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.

The fact that there is no flow on line 3-4 conflicts with the rule that cross-border capacity should be used optimally. The capacity on this line can be freed up in two ways: by curtailing wind at Node 4 and/or 5, or by counter trading the exported volume. Counter trading shifts costs to the consumers without improving the economic efficiency of the system, while curtailing wind generation will lead to an increase in fossil fuel generation onshore.

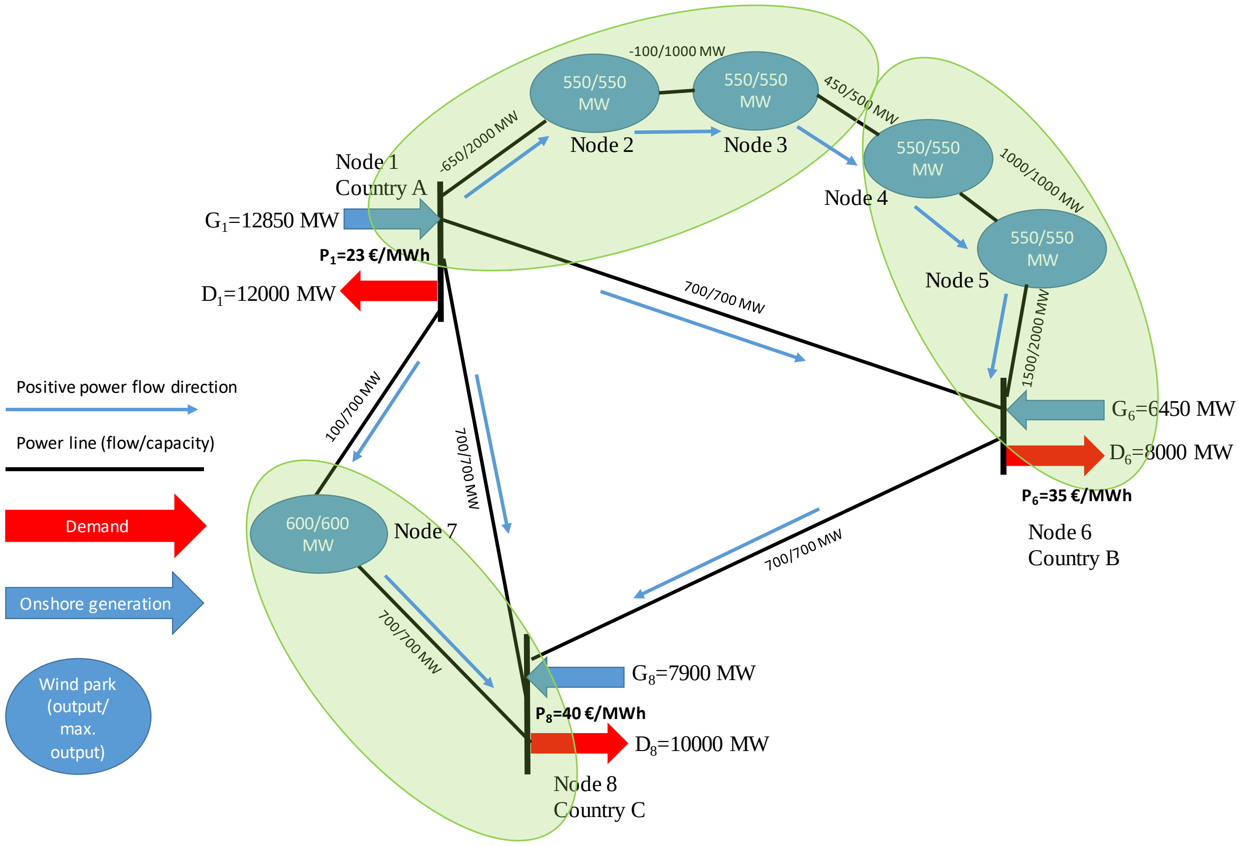


Figure 64- Wind parks part of national price zones, 50% wind generation.

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 7 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 64 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.

A second consequence is that line 1-7, which is an interconnector between Countries A and C, is underutilised, in view of the regulation to maximise cross-border capacity. Again, possible solutions are curtailment in Node 7, which is technically not necessary and undesirable from an economic point of view, and counter trading.

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 18, the wind park revenues are shown; the wind parks are indicated with a W and their nodal number.

Table 19 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 20 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 21, because the capacity of the meshed offshore grid that is not used for evacuating wind power is used as interconnection capacity.

Table 18 - Wind park revenues, national price zones, high wind.

	Output MW	Price €/MWh	Revenue €/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 19 - Line flows and congestion rent, national price zones, high wind.

Line	Flow MW	$P_{low\ node}$ €/MWh	$P_{high\ node}$ €/MWh	Congestion rent €/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 20- Wind park revenues, national price zones, low wind.

	Output MW	Price €/MWh	Revenue €/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 21- Line flows and congestion rent, national price zones, low wind.

Line	Flow MW	$P_{low\ node}$ €/MWh	$P_{high\ node}$ €/MWh	Congestion rent €/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 65

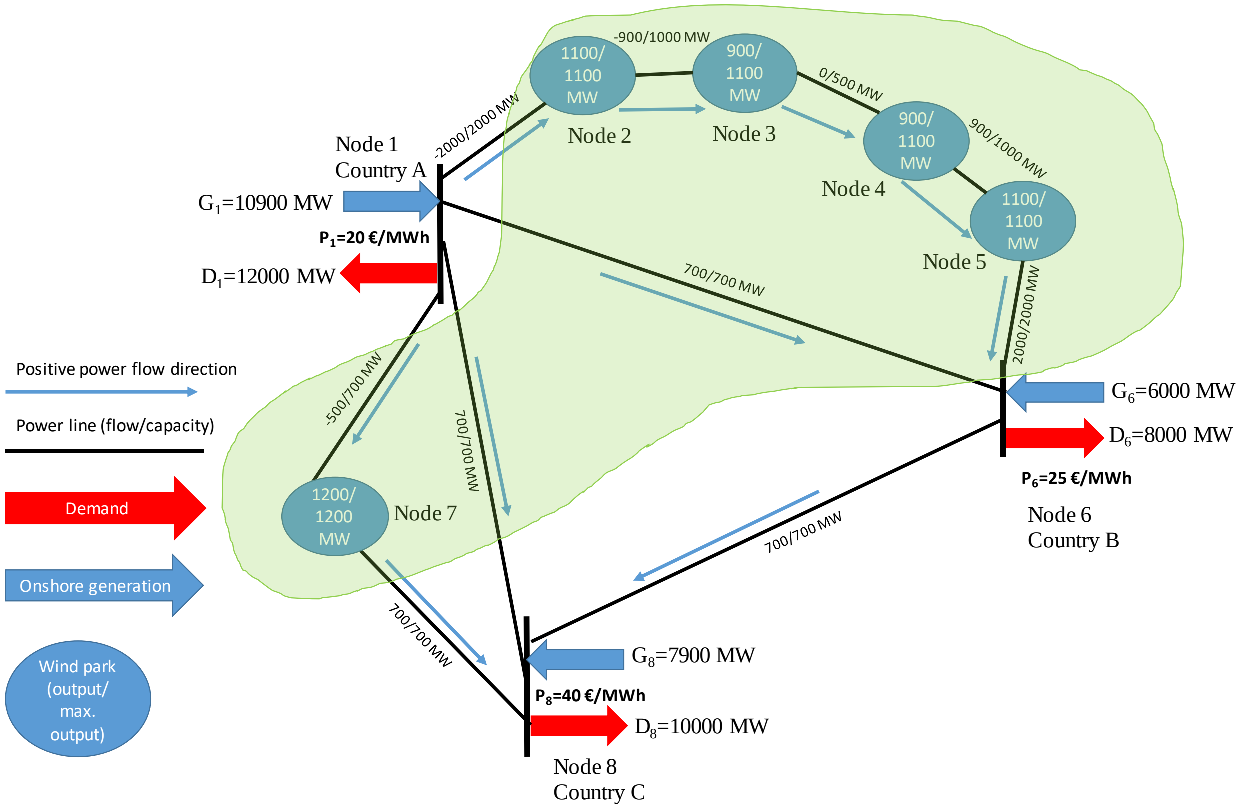


Figure 65- A single offshore price zone, high wind.

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 66 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 in the previous Section.) 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.

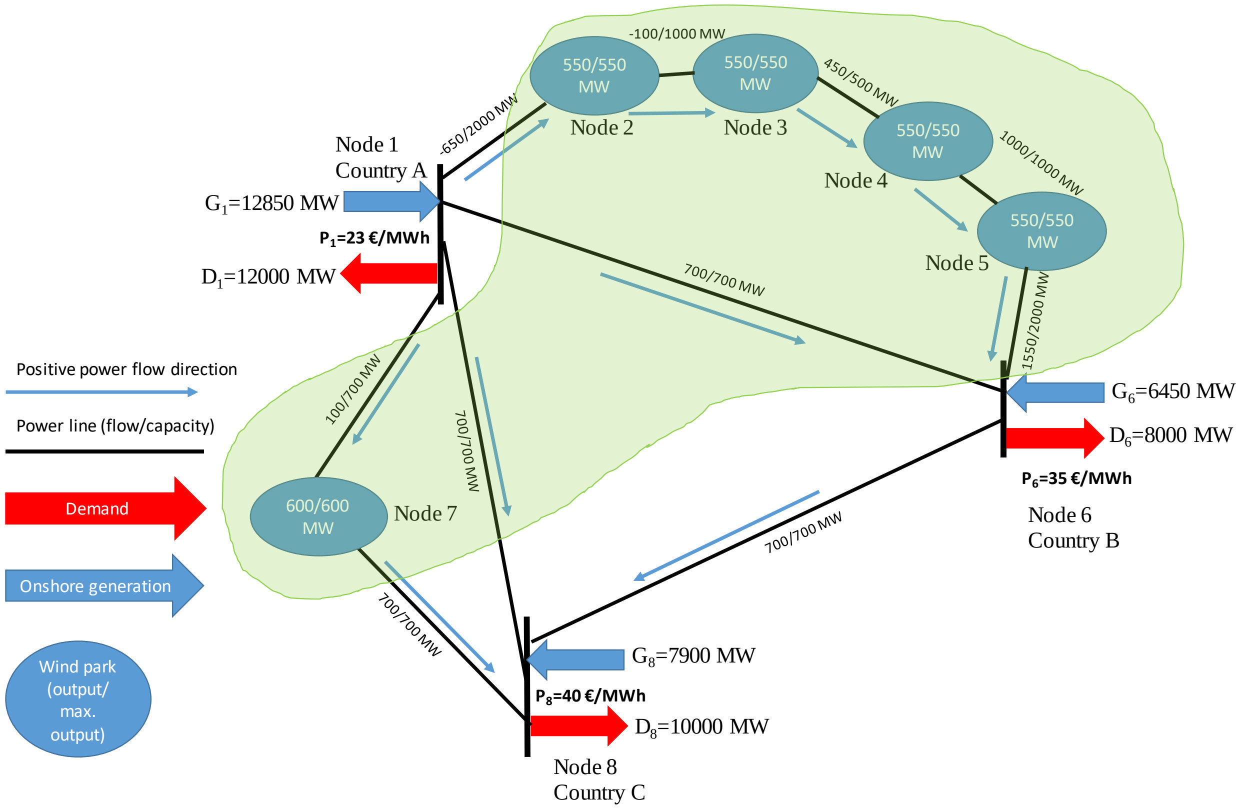


Figure 66 - A single offshore price zone, 50% wind capacity.

Table 22 shows the offshore wind revenues in the high wind case and Table 24 in the low wind case. They are substantially lower than in the national price zone model. Table 23 and Table 25 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 22- Wind park revenues, single offshore price zone, high wind.

	Output MW	Price €/MWh	Revenue €/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 23- Line flows and congestion rent single offshore price zone, high wind.

Line	Flow MW	$P_{low\ node}$ €/MWh	$P_{high\ node}$ €/MWh	Congestion rent €/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 24- Wind park revenues, single offshore price zone, low wind.

	Output MW	Price €/MWh	Revenue €/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 25- Line flows and congestion rent, single offshore price zone, low wind.

Line	Flow MW	$P_{low\ node}$ €/MWh	$P_{high\ node}$ €/MWh	Congestion rent €/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, 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.

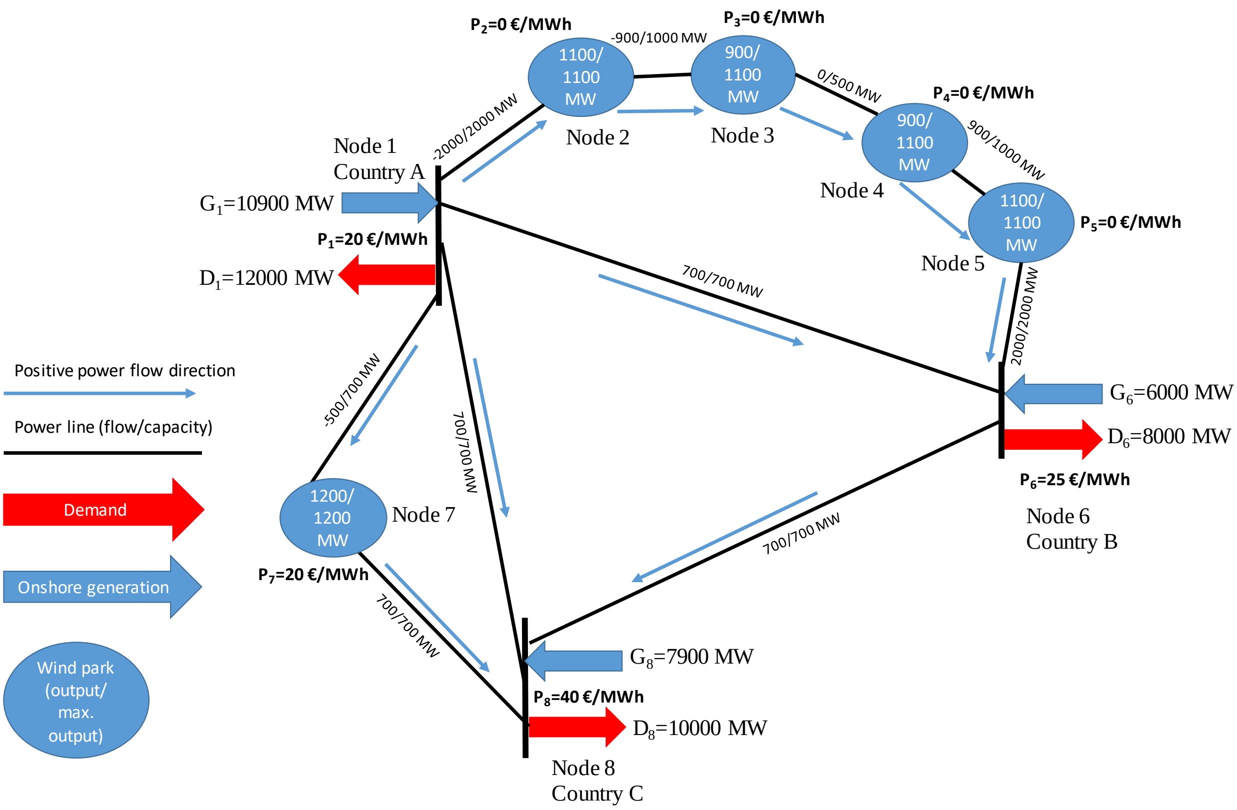


Figure 67- Small price zones, high wind generation.

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.[67] 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.

Figure 68 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 26 and Table 27.) 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.

[67] 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.

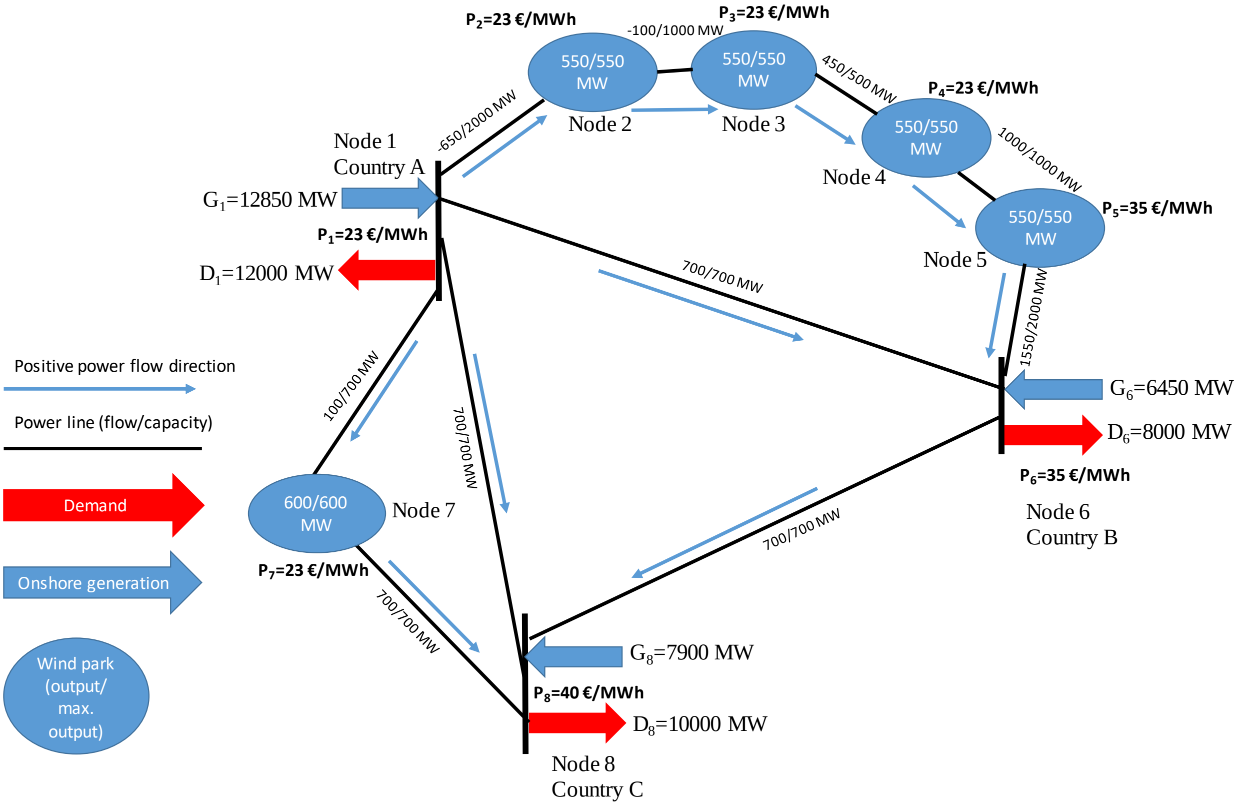


Figure 68- Small price zones, 50% wind generation.

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, as shown in Figure 68. 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.)

Table 26 - 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 27- 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 28- 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 29- 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

COMPARISON AND EVALUATION

COMPARISON OF THE NUMERICAL EXAMPLES

We will now compare the effects of the three 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.[68] 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 the Section on the National Price Zone. (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.)

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

[68] There are other aspects to market design, such as the balancing market, which we have not discussed.

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 the Section on the Small Price Zones, 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 the following section we will discuss options for compensating wind farm operators in case curtailment reduces their revenues unacceptably and 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 [28] 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 area, 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 facility 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 67.

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.

LIMITING THE RISK OF NETWORK CONGESTION TO PARK OPERATORS

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 put options for the onshore market prices by the market operator. They would receive this price for the volume of the option. 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 market operator, who is the counterparty for the contracts, should ensure that the volume of the option contracts (in MW) does not exceed the volume of grid capacity that he can reliably provide, so the revenues from selling electricity onshore cover the option contract obligations.

The effect of this arrangement is that the wind farm operators receive onshore prices, 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 still cause the price in the offshore zone to drop to zero. This would make the wind farm operators indifferent to being curtailed for the volume of generation that is not covered by the put options and provide energy storage or power-to-X facilities in the offshore zone with an incentive to consume the excess generation.

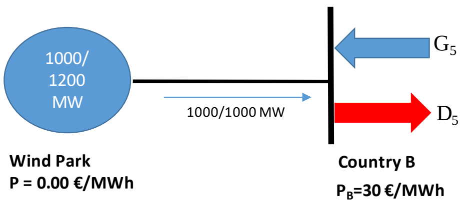


Figure 69- Put options, simple case.

The principle can be illustrated with Figure 69. The wind park needs to be curtailed, so according to the logic of the small zones model, the price would be zero. 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 put options 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. Giving the wind park operator a put option for 1000 MW for the price of Country B would allow it to sell 1000 MW at a price of 30 €/MWh. The remaining 200 MW would still have a value of zero, so he would be indifferent to curtailment. An offshore storage or power-to-X operator could buy this power.

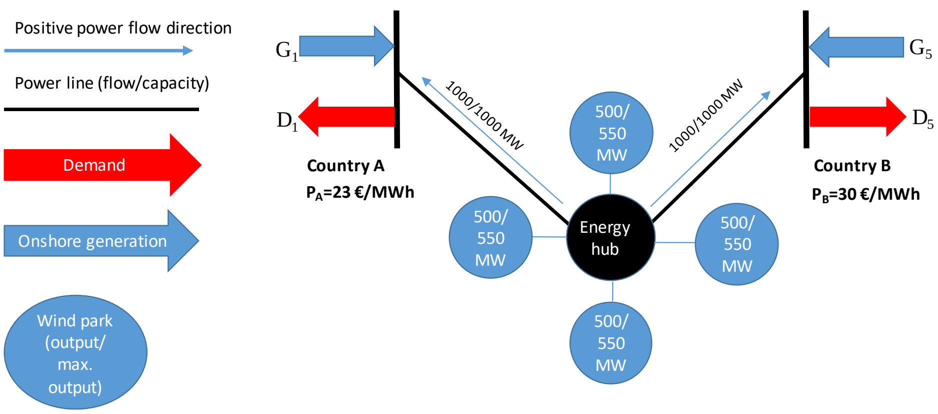


Figure 70 - Put options, energy hub.

In case of an energy hub that is connected to two zones, the park operators could be given put options in proportion to the connections to the two zones. See Figure 70. In this case, each park could be provided with 250 MW worth of put options for each country, providing them with 250 MW worth of sales for the price of Country A and the same volume in sales in Country B. The remaining 50 MW of each park would be worth zero and would need to be curtailed. An interesting case develops when there is less wind: then the hub price becomes the 23 €/MWh (the price of Country A), but the park operators can still sell 250 MW each at the price of Country B. So the options also provide a benefit in case of less wind.

The proposed put options are economically similar to financial transmission rights, but the financial flows differ in a crucial way. Payments that follow from financial transmission rights are made by TSOs to the (wind) generation companies. The TSOs can make these payments because they are equal to, or smaller than, the congestion rents. However, current European regulation does not allow the return of congestion rent to generation companies. In case of the put options, the wind generators simply have a right to the onshore prices for certain volumes of generation. This reduces congestion rent by the same amount, but the TSO is not involved in collecting and paying out these sums.

In conclusion, put options 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 put options, 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 71. 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 that is described in the previous Section would return the price to the national price.

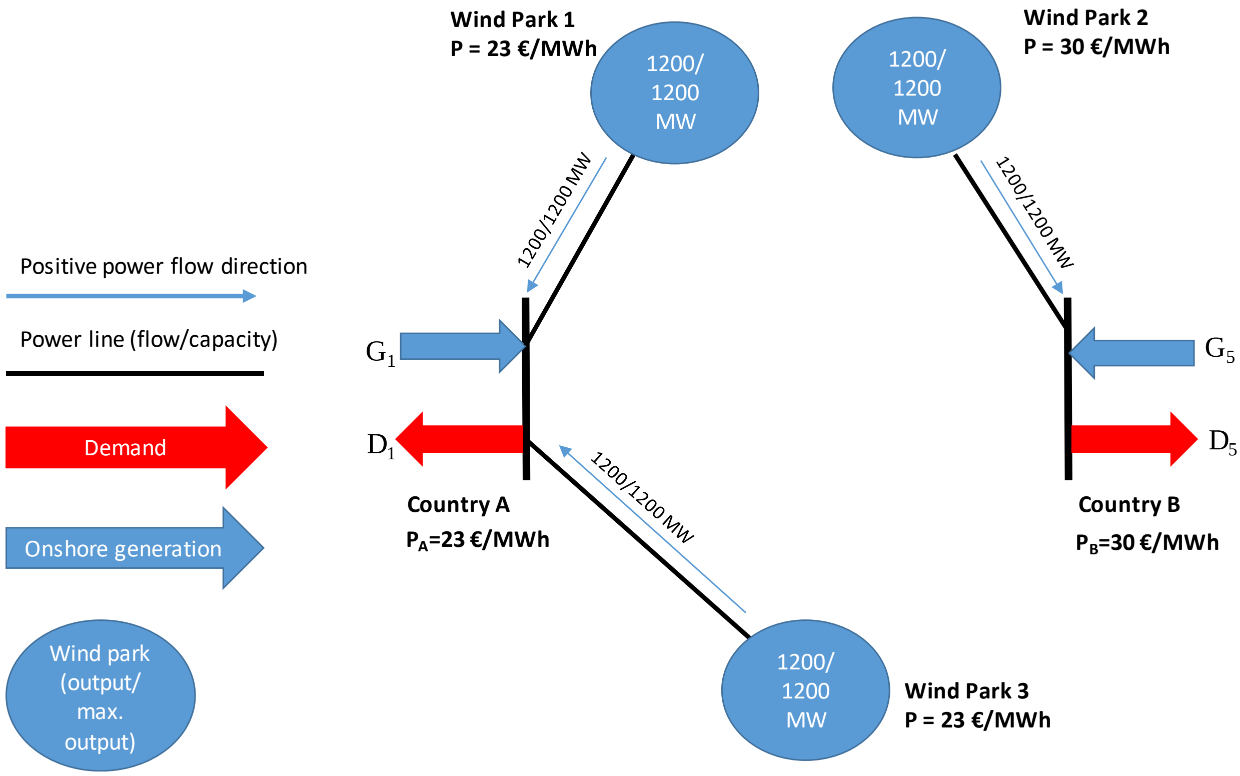


Figure 71- Wind parks with single connections.

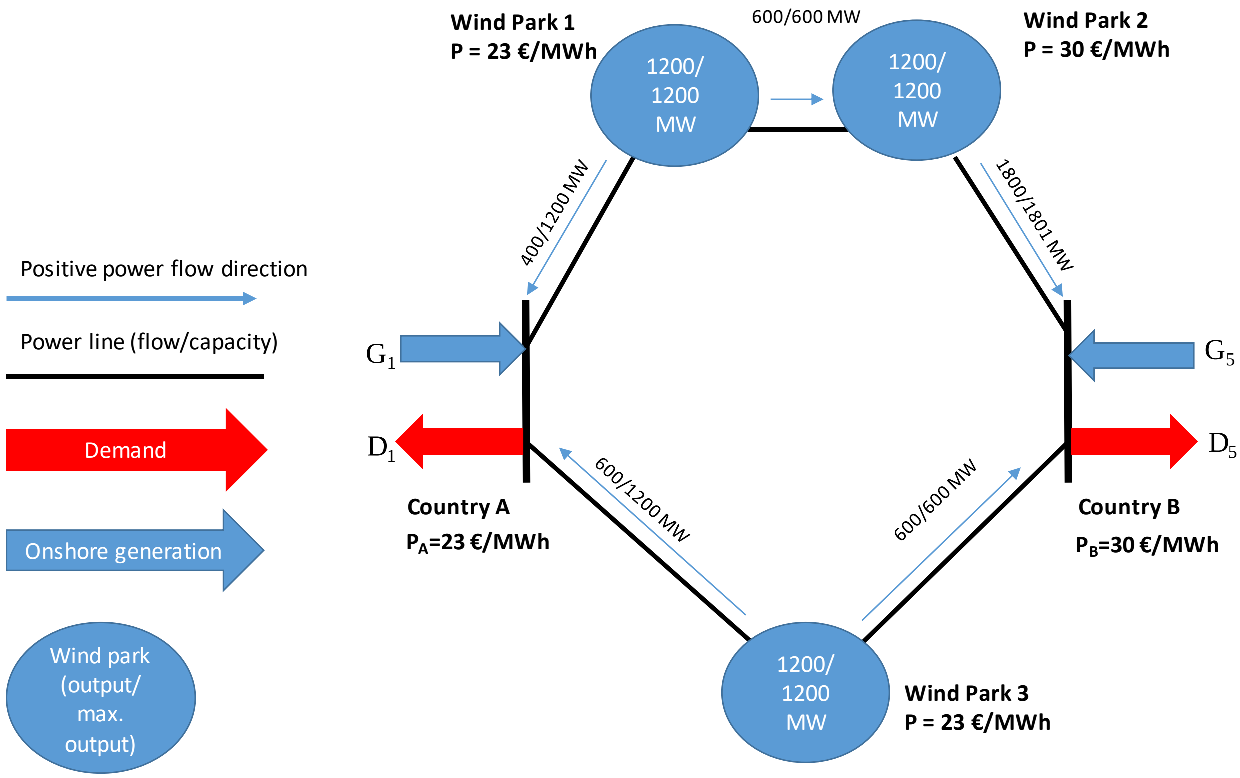


Figure 72- Simple network, small price zones.

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 72. 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 73. 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.

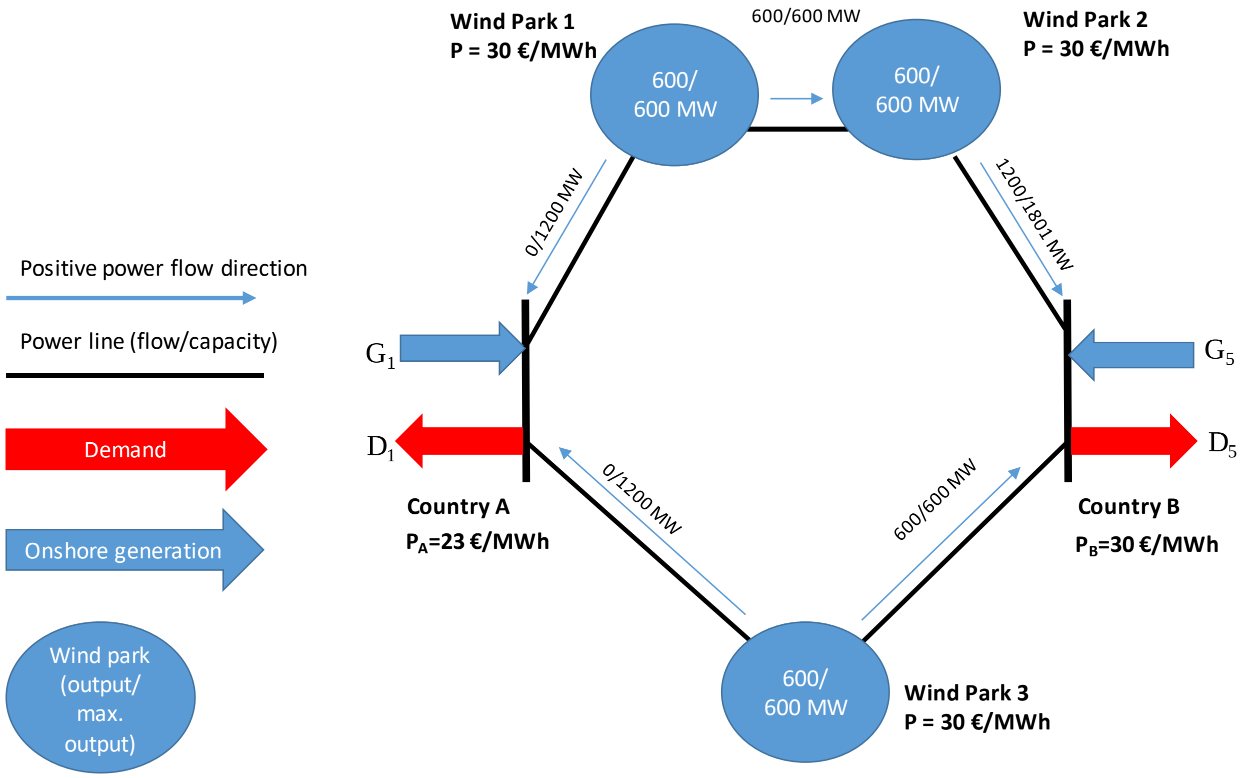


Figure 73- Simple network, small price zones, less wind

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 providing them with put options for onshore market prices. 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 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 put options for onshore prices 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 put options, 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.

APPENDIX VI – 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 30). 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 30- 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, WP 8, 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.