PROMOTioN
PROGRESS ON MESHED HVDC OFFSHORE TRANSMISSION NETWORKS

D12.2 - Optimal Scenario for the Development of a Future European Offshore Grid

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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PROJECT REPORT

DOCUMENT INFO SHEET

Document Name:	**Set-up for Deliverable 12.2:**
	Working document for discussion
Responsible partner:	TenneT TSO B.IV.
Work Package:	WP12
Work Package leader:	TenneT TSO B.IV., John Moore
Task:	T12.2
Task lead:	TenneT TSO B.IV., John Moore

DISTRIBUTION LIST

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WP Leader:	John Moore	TenneT TSO B.IV.

DOCUMENT HISTORY

Version	Date	Main modification	Author
1.0	12-12-2018	First setup	Tim Kroezen
2.0	25-02-2019	Edits to CBA chapter, textual and visual edits and changes in all chapters	Tim Kroezen
3.0	26-02-2020	Finalisation of document	Jelle van Uden, Olivier Antoine, Felix Rudolph

WP Number	WP Title	Person months	Start month	End month
WP12	Deployment plan for future European offshore grid	177	12	48

Deliverable Number	Deliverable Title	Type	Dissemination level	Due Date
D12.2	Optimal Scenario for the Development of a Future European Offshore Grid	Report	PROMOTioN	31/12/2018

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 691714.

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LIST OF ABBREVIATIONS

ACRONYM	FULL NAME
AC	Alternating Current
BAU	Business as Usual (concept)
CAPEX	Capital Expenditure
CBA	Cost-Benefit Analysis
CSC	Current Source Converter
DC	Direct Current
DCCB	Direct Current Circuit Breaker
DG	Distributed Generation (TYNDP scenario)
DP	Deployment Plan
DRU	Diode Rectifier Unit
EBSA	Ecological and Biological Significant Areas
EEZ	Exclusive Economic Zone
EIA	Environmental Impact Assessment
ENS	Energy Not Served/Supplied
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
EUR	European Distributed Hubs (concept)
GCA	Global Climate Action (TYNDP scenario)
GIS	Geographic Information System
HUB	European Centralised Hubs (concept)
HVDC	High Voltage Direct Current

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IPBES	Intergovernmental Science-Policy Platform on Biodiversity and Ecosystem Services
KPI	Key Performance Indicator
LCOE	Levelised Cost of Energy
LOLE	Loss of Load Expectation
MILP	Mixed Integer Linear Programming
MOG	Meshed Offshore Grid
NAT	National Distributed Hubs (concept)
NSCOGI	North Seas Countries' Offshore Grid Initiative
NTC	Net Transfer Capacity
OPEX	Operational Expenditure
OTEP	Optimal Transmission Expansion Planning
OWF	Offshore windfarm
PV	Photovoltaic (in: Solar PV system – used for solar energy)
RES	Renewable Energy Sources
ST	Sustainable Transition (TYNDP scenario)
TRL	Technology Readiness Level
TSO	Transmission System Operator
TYNDP	Ten Year Network Development Plan
UK	United Kingdom
VEC	Valued Ecological Component
VSC	Voltage Source Converter
WP	Work Package

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EXECUTIVE SUMMARY

INTRODUCTION

At the end of 2019, 22.1 GW of offshore wind capacity was installed across Europe with 77 % 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 this trend continues, with a clear continuation of projects stretching over the next decade across the North Seas countries [2]. Currently, most of this wind generation (~16 GW) is near shore and 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 to reduce transmission losses increases. Additionally, with longer distances, the need to more efficiently utilise offshore transmission assets becomes more important. As a result, a meshed or multi-terminal offshore grid is proposed as a solution to this, where multiple windfarms may be aggregated (i.e. connected to a single transmission asset) and interconnection between countries may be established through the offshore grid. The evolution from point-to-point to multi-terminal and meshed grids could be an attractive option to satisfy European Union goals to efficiently integrate renewable energy and increase interconnection, while maximising social benefit.

The PROMOTioN programme (Progress on Meshed HVDC Offshore Transmission Networks) advances the HVDC technology required to design, build, operate and protect meshed HVDC transmission grids, and the legal & regulatory, economic, financial, market and governmental aspects around building such grids. In this document, the analyses and conclusions of the technical and non-technical works are brought together and combined with estimates of the costs and benefits of establishing an offshore HVDC grid for the evacuation of wind generation. In this document, it is assumed that all non-technical conditions facilitate development of this kind of grid. How and when to develop these favourable conditions is discussed in Deliverable 12.4 – *Final Deployment Plan for an HVDC offshore grid*.

This Deliverable is structured in four sections:

1. The development of wind generation scenarios,
2. The introduction of offshore grid concepts and their optimisation to create realistic topologies,
3. The cost-benefit analysis of the topologies.
4. Conclusions.

A summary of sections 1 to 3 is provided in this Executive Summary.

WIND GENERATION SCENARIOS

Forecasting the long-term deployment of offshore wind is inherently uncertain. In order to reflect these uncertainties, three different 2050 wind capacity scenarios are considered in PROMOTioN. The definition of these scenarios is based on a review of several existing studies, which give a realistic range of installed offshore wind capacity in the North Seas out to 2050. These are used to compile three deployment scenarios – High wind (optimistic), Central wind (medium) and Low wind (pessimistic) – detailed in **Error! Not a valid bookmark self-reference.**.

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Table 1 - Development of offshore wind generation in the North Seas according to the three scenarios defined in PROMOTioN (values in GW).

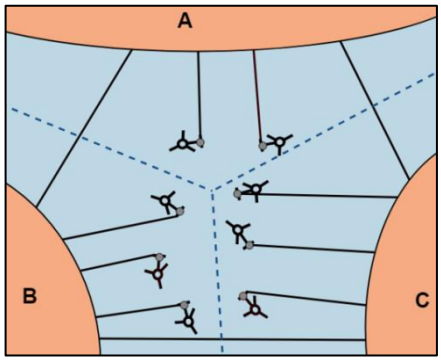
	2020	2025	2030	2035	2040	2045	2050
High wind	19.6	40.0	65.0	95.0	125.0	160.0	205.0
Central wind	19.6	34.0	49.0	67.0	90.0	115.0	150.0
Low wind	19.6	27.0	36.0	47.0	58.0	72.0	90.0

To allocate this capacity to specific locations, each potential location in the North Seas is assessed in terms of average wind speed, bathymetry, distance to shore for grid connection, and shore-side support (harbours). Exclusion areas (e.g.: marine protected areas) and other constraints (e.g.: existing wind farms, shipping lanes, etc.) are considered as well. In addition, a maximum capacity for offshore wind is set for each Exclusive Economic Zone (EEZ) of every North Seas country. This national limit is based on their peak demand load and several studies; especially the European Network of Transmission System Operators for Electricity (ENTSO-E) Ten Year Network Development Plant (TYNDP) 2018.

These two aspects (site suitability and national limits) are finally combined into a single weighted factor which acts as a merit order for offshore windfarm (OWF) locations. In the end, the best ranked locations are selected within each countries' capacity limit for each of the three scenarios. These locations are then divided in those suitable for fixed bottom wind turbines and those suitable for floating wind turbines, which influences the amount of offshore wind capacity the area can host.

CONCEPTS AND TOPOLOGIES

A transmission grid has to be planned and constructed to evacuate wind energy to shore[1]. PROMOTioN investigates how the offshore transmission network in the North Seas may develop in response to the three wind generation scenarios described above. In order to capture different levels of complexity and cooperation between the North Seas countries, four distinct design philosophies are considered for each of the three deployment scenarios. Descriptions for each of these *concepts* are given in Figure 1 below. It should be stressed that they illustrate relatively extreme or exaggerated options. The exercise therefore does not aim to create four actual options, but to illustrate possible extreme routes exist and to compare the potential benefits of each option.



Business as usual (BAU)

The offshore wind farms continue to be connected radially to the grid. This may be in separate point-to-point connections, but some OWFs might also be bundled to reach a critical size of 2 GW. This standardised 2 GW concept utilises the most current HVDC equipment and is therefore the continuation of a near-future high-end concept. Power exchange between countries is facilitated by separate point-to-point interconnection.

[1] PROMOTioN assumes that all wind generation will be evacuated to shore. Power to gas and other offshore storage is not considered.

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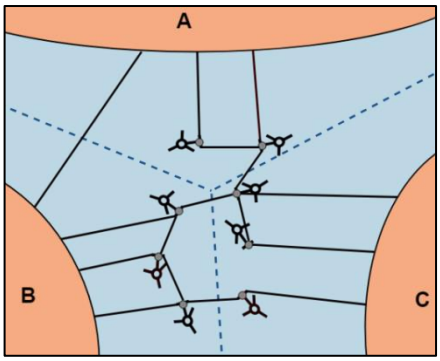
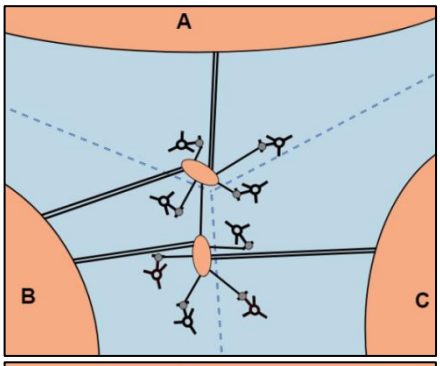


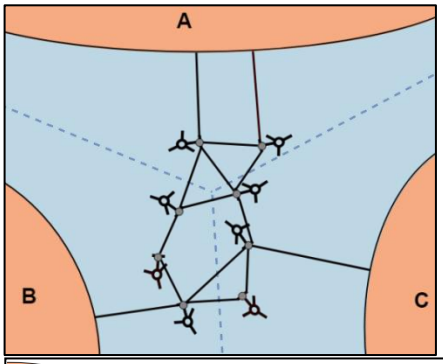
National Distributed Hubs (NAT)

This concept is based on a national approach to offshore grid construction. The purpose 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 cooperation 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 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.

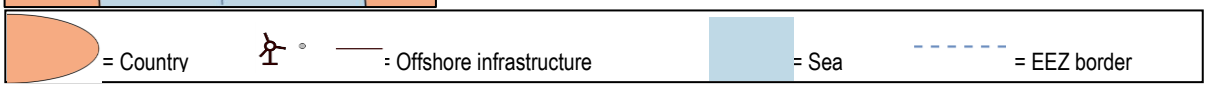


Figure 1 - Illustration of the different concepts.

Given that each concept has its own design principles, they can be translated into rules in an optimisation model. Optimising the model to meet the wind generation scenarios then leads to *topologies*. Topologies describe the grid temporal development under each wind capacity scenario. Indeed, in the topology generation, the concepts develop gradually and evolve progressively over time, rather than each concept being structured immediately as needed by the target of each scenario. This entails the assumption that investments are done stepwise, with anticipation and coordination between projects.

The optimisation process is in fact divided into three main steps. Step 1 focuses mainly on investment costs to evacuate offshore wind energy, step 2 uses a market model to optimise interconnection capacity and step 3 assesses the technical feasibility and analyses the security of the optimised grid topologies.

The optimisation process is completed by a sensitivity analysis to quantify the robustness of results against changes in assumptions. The sensitivity is evaluated with respect to converter rating, cable rating, onshore hosting capacity and potential offshore storage.

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Comparing the results of the optimisation and the sensitivity analysis provides interesting conclusions and key messages that are summarised below:

- With standardised 2 GW platforms aggregating several wind farms (satisfying current onshore infeed constraints), a radial configuration is the first building block of an offshore grid and is a competitive option compared to meshing of the grid. In the context of PROMOTioN, 2 GW 525 kV DC is chosen but radial configurations may exist of any size.
- Combined use of the offshore grid for wind evacuation and interconnectors is an important driver for meshing / multi-terminal connections.
- In the three meshed concepts and scenarios, the topology evolves gradually from a few multi-terminal connections to a more complex structure. Eventually, a backbone will interconnect several multi-terminal connections. The Dogger Bank seems to be an ideal location for this backbone because of limited distances to favourable wind farm locations. As the Dogger Bank is a Nature 2000 protected area, in reality, the construction of such a backbone should be carefully considered.
- All wind scenarios require a high level of interconnection. For the high wind scenario, even with increased interconnection capacities, this will not be enough to evacuate all the produced energy. Therefore, large-scale storage may be needed to avoid curtailment. This statement is true within the limited geographical scope of the PROMOTioN project and could be influenced by broadening the geographical scope.
- The results appear to be very sensitive to input assumptions, especially the cable length required for each concept.

COST-BENEFIT ANALYSIS

In order to compare the generated topologies, their full costs and benefits need to be calculated and analysed. A Cost-Benefit Analysis (CBA) provides a structured means of assessing and comparing the net benefits to society for the four concepts under the three offshore wind deployment scenarios. The objective is to assess the cost effectiveness of each specific solution to leverage Europe's offshore wind resources in the North Seas, while maximising social benefits for consumers. However, it should be emphasised that it is not the explicit intention of the CBA to select a single 'best' design for an offshore transmission network in the North Seas, but rather to explore the values, both quantitative and qualitative of each concept under different deployment scenarios. In doing so, the value of the different grid configurations, both cost-wise but also socio-economic, are analysed.

The CBA methodology used in the PROMOTioN project is detailed in Deliverable 7.11 – *Cost-benefit analysis methodology for offshore grids*. This methodology proposes assessing each concept against a series of key performance indicators (KPIs). It is based on established methods from the ENTSO-E, modified for the purpose of analysing the construction of a full grid, as opposed to single projects within an existing grid.

For the cost analysis, the topologies are first broken down into their individual components. Investment costs for each component were collected from the industry. The cost analysis takes into account:

- C1: the capital expenditure (CAPEX) associated with the preparation, design, fabrication and construction of all components.
- C2: the operational expenditures (OPEX) associated with the operation during the considered period.

Please note that the onshore grid reinforcement requirements as a result of bringing the offshore energy to shore are not calculated within PROMOTioN. The onshore grid costs are limited to onshore converters only with the onshore landing points located in coastal areas.

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The benefits are quantified as much as possible, according to the methodology in Deliverable 7.11, and otherwise qualitatively described. The benefit analysis takes into account:

- B1: the socio-economic welfare increase due to increased interconnection capacity which leads to wholesale price convergence.
- B2: the effectiveness of each concept to integrate renewable energy sources.
- B3: the difference in CO_2 emissions as a result of offshore wind energy integration.
- B4: the increase in societal well-being due to factors such as increased air quality due to phase-out of non-renewable energy sources.
- B5: the change in grid losses (onshore and offshore).
- B6: the adequacy of supply, measured in terms of expected energy not transported due to outages of transmission components, as well as the loss of load expectation when peak load exceeds the available generation capacity.
- B7: the flexibility of supply, measured in terms of increase in alternative paths for energy evacuation, and smoothing of generation profiles.
- B8: the security of supply, measured in terms of ability of the system to cope with disturbances and access to restoration capabilities across the network.
- B9: the resilience of supply, measured in terms of ability of the grid to withstand physical or cyber-attacks and natural disasters.

Additional social factors are also considered:

- S1: environmental, which represents amount of equipment needed to build each topology (cable length, number of platforms etc.) and its impact on the environment.
- S2: social, which measures specifically the impact on the coastal population of building the grid.
- S3: other factors that are not previously included in any benefit category, like increased sustainability, geopolitical independence or increased European cooperation.

CONCLUSIONS

From the CBA presented in this document, several conclusions can be drawn. These conclusions concern the onshore grid and the three major grid configurations that were applied in the concepts: point-to-point evacuation of wind energy, meshing and the application of artificial islands.

The first lesson learnt from the CBA is that no topology has a decisive advantage over the others examined, although the European Centralised Hub concept does show a significant cost advantage. However, all structures have different advantages and disadvantages and a range of costs and benefits. Therefore, the most probable temporal evolution of the offshore grid will start from radial connections, similar to those existing today. As distances between new wind farms and shore increases, the grid will grow by including more meshing / multi-terminal connections and also tend toward to a structure with hubs. The following section provides some high-level considerations and recommendations for point-to-point connections, interconnections, artificial islands and the onshore grid.

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POINT-TO-POINT CONNECTIONS

The current point-to-point connection remains a competitive option and is the first building block for each topology. The topology generation indicates the possibility for a significant number of 2 GW OWFs in each of the topologies[2].

- It is assumed that cost reductions for 2 GW point-to-point connections may be obtained by standardising a 2 GW 525 kV platform and converter design to be applied throughout the North Seas.
- It is recommended to coordinate maritime spatial planning as this is key to reach 2 GW by "aggregating" OWFs connected to a single offshore HVDC platform. This allows the application of a standardised 2 GW concept and economies of scale. The sensitivity analysis outlined that the point-to-point solution remains competitive, if the typical platform size and cable rating are similar. If this is not the case, the point-to-point solution becomes significantly more expensive.
- With the energy density used in PROMOTioN, 2 GW requires around 200-400 km^2 of sea area. This appears realistic from the Geographic Information System (GIS) study and allows AC connections to an offshore HVDC platform.
- Direct AC connections from the windfarm to the offshore converter in 66 kV bring a cost reduction and it is therefore recommended to apply this into the 2 GW concept.

INTERCONNECTIONS

Given that all wind scenarios require a high level of interconnection to increase socio-economic welfare, it is recommended to apply hybrid interconnection where this is optimal, i.e. when two OWFs in different EEZs are close to each other. This creates an interconnection for a moderate investment. Nevertheless, there are no clear benefits to connect all the multi-terminal structures together to form a single grid as the benefits of a higher interconnection capacity will not offset the extra-costs and complexity involved. Therefore, it is recommended to apply meshing only when this leads to a significant decrease in cable length compared to point-to-point interconnection, i.e. when the meshed structure has high benefits to both countries which would otherwise require a point-to-point interconnector.

ARTIFICIAL ISLANDS

The cost-benefit analysis of the HUB concept shows that artificial islands in places where there is high density of wind energy generation can significantly reduce costs.

Although not further studied within PROMOTioN, there is a critical distance from the windfarm to the island at which connection to the artificial island is economically more sensible then direct connection to shore. This distance is context-dependent and influenced by multiple factors, including:

- the position of the OWF with respect to the artificial island and to an onshore connection point,
- the possibility to connect several OWFs to the island,
- the possibility to combine several OWFs into a single cable to shore from the island,
- the existence of flexibility on the island,
- and the interconnection capacity of the island.

[2] Due to this, these recommendations are steered towards a 2 GW 525 kV HVDC concept, but these recommendations are valid for other sizes as well. Within PROMOTioN, the 2 GW maximum size is used because of the current available technology, as discussed previously.

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It is therefore recommended that artificial islands are planned in coordination with the establishment of multiple OWFs, as these factors are also influenced by the presence of other OWFs[3].

The artificial islands in the HUB concept are considered to be a credible alternative to interconnected offshore DC platforms. PROMOTioN has studied two options: (1) an option to connect on the HVAC side and (2) an option to interconnect on the HVDC side converters (e.g. with a ring-like DC bus bar). Interconnection of the HVDC allows more efficient transportation of wind energy, without additional converter losses and the possibility to better control power flows. The drawback is that such a structure would require a protection system and circuit breakers. It is therefore recommended to further study potential designs of the artificial islands, thereby including different interconnection options of the converters and the option of flexibilities on the islands.

ONSHORE GRID

In the sensitivity analysis of the topology generation, it was shown that increasing the onshore hosting capacity[4] reduces the total cable length required for all concepts significantly, but is especially beneficial for the NAT, EUR and HUB concepts. This shows that a strong coordination between offshore grid development and onshore grid development can lead to significant reductions in cable length, and thus costs, in the offshore grid.

Additionally, in the benefit analysis for the High wind scenario, it was shown that in the concepts with an increased offshore coordination, i.e. the EUR and HUB concepts, there is a counterintuitive increase of offshore wind energy curtailment. In these concepts, not all wind energy that is transported to land can be transported to areas with high demand. As this is calculated by the model, the model chooses to curtail the offshore wind. For this reason, it is again recommended to take into account the capacity of the onshore grid in planning the offshore grid. This is needed to facilitate either an increase of interconnection capacities onshore or large-scale storage onshore and/or offshore.

DISCUSSION

Several discussion points were raised while performing the CBA. These should carefully be considered as these shape the conclusions to the analysis:

(1) *Impact of the offshore grid on the onshore grid needs to be studied in depth*. Even though this topic is not covered within the PROMOTioN project, it is clear that the onshore grid must be reinforced for transmission of the offshore wind energy to areas with high demand.

(2) *With a massive deployment of offshore wind energy, an increasing amount of flexibility is considered necessary to avoid curtailment*. PROMOTioN has not evaluated any flexibility options (such as batteries, Power-to-X, Demand Side Management, etc.). Offshore storage, especially in the case of the HUB concept where wind energy is concentrated to artificial islands, could be a promising option as it would allow smoothing of the flows in the offshore grid and optimal scaling of the cables.

(3) *Within PROMOTioN, it has been decided to conduct the research with currently available – or nearly available – technologies*. There is no accurate prediction of the evolution in technologies, but it is generally assumed DC components may become mass-producible, less expensive, more efficient, standardised, smaller and with higher rating. All these factors will reduce the total cost of deployment but are at this stage highly uncertain.

[3] For example, flexibilities may only be beneficial when a larger number of OWFs are connected to the island. It is therefore not advised to assess the economic viability of connecting to an artificial island for each single OWF separately but rather in conjunction with other OWFs.

[4] The onshore hosting capacity is the capacity of the onshore connection point. This capacity is limited to 4 GW in the analysis in order to inherently take into account the constraints of the onshore grid to further transport the energy inland.

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1 INTRODUCTION

In the course of the ratification of the Kyoto protocol in 2005, the presidency conclusions of the Council of the European Union (EU) included a proposal for “an integrated climate and energy policy” [4]. The objective of this policy is to limit “the global average temperature increase to not more than 2°C above pre-industrial levels”. In addition, the Paris agreement reaffirms the goal of limiting the global temperature increase to not more than 2°C, "while urging efforts to limit the increase to 1.5°C" [5]. The EU has since set interim targets for 2030 to meet this aim [6] [7] [8]:

TARGETS FOR 2030

- A 40% cut in greenhouse gas emissions compared to 1990 levels (with a desire to increase this to 55% to bring it in line with the Paris Agreement).
- At least a 32% share of renewable energy consumption
- Indicative target for an improvement in energy efficiency at EU level of at least 27% (compared to

By the end of 2019, 22.1 GW of offshore wind capacity was installed across Europe with much of this capacity concentrated in the North Seas [1], see Figure 1-1. This is a 10-fold increase in capacity over the last decade, and this continues to grow, with a clear pipeline of projects stretching into the 2020s across the North Seas [2]. The aim of the PROMOTioN (Progress on Meshed HVDC Offshore Transmission Networks) project is to take a longer term view out to 2050 and consider how the capacity of offshore wind may evolve and how the offshore transmission network in the North Seas could develop in response, in order to efficiently evacuate offshore wind power to shore.

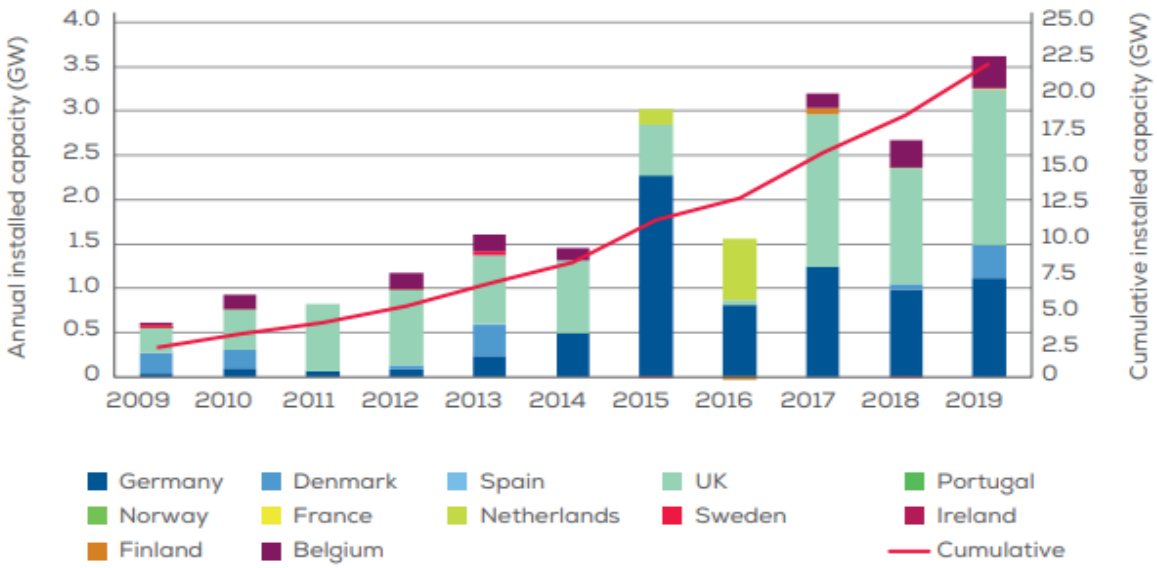

Figure 1-1 - Annual offshore wind installations by country (left axis) and cumulative capacity (right axis) [1].

The PROMOTioN project identified technology innovation needs and non-technological issues and designed a programme to alleviate some of the critical challenges. The project has ten research and laboratory test programmes, referred to as Work Packages (WPs), that each tackle specific technical and non-technical barriers that have been identified. PROMOTioN has researched and tested four key HVDC technologies, namely control

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systems, DC Circuit Breakers (DCCBs), HVDC protection systems and Gas-Insulated Switchgear[5]. To further decrease technological barriers, research was also aimed at harmonising the standardisation of these technologies to ensure interoperability of different combinations of infrastructure from different manufacturers. A policy recommendation package is also proposed that incorporates the legal, economic and financial frameworks that aim to address non-technical barriers.

These key technologies and accompanying policy recommendations would allow the MOG to develop in multiple configurations, or grid development *concepts*, that vary in level of technological and cooperative complexity. Additionally, given the inherent uncertainty in long term forecasts of offshore wind capacity and in the costs of developing different transmission network designs, it is necessary to explore the development of the different concepts under different offshore wind deployment scenarios. The purpose of this Deliverable is to give insight into the development of the concepts and deployment scenarios that are used in the analysis of the potential for offshore wind in the North Seas[6]. As each of the concepts represents different challenges as well as different design philosophies, it is important to assess the costs and benefits of each concept. To do so, a methodology developed specifically by PROMOTioN in Deliverable 7.11 – *Cost-Benefit Analysis methodology for offshore grids*[7] was applied and this document provides details of cost benefit analysis carried out and an interpretation of the results. A CBA provides a structured means of assessing and comparing the net benefit to society of these different concepts under different offshore wind deployment scenarios. Demonstrating the cost effectiveness of a solution to harness these resources is a fundamental requirement to unlock the full potential of Europe's offshore resources in the North Seas.

PROMOTioN is not the first project to examine offshore grid development in the North Seas. Numerous studies have undertaken CBAs to examine the merits of developing a MOG in the North Seas. These studies have differed in their geographical scope and in the methodology and assumptions used to develop and compare the costs and benefits of different concepts. The CBA for the PROMOTioN project builds on these previous studies, taking into account the latest researched data available on technology costs and the technical progress made in HVDC components and operation during the PROMOTioN project. For example, in the CBA of PROMOTioN the protection system is designed in a far greater detail than in previous studies. In previous research studies[8] and EU-funded projects, different challenges for the development of offshore grids have been identified:

- On a technical level there remains a lack of agreement among operators and manufacturers on system architecture, control structures, protection schemes and interfaces to ensure interoperability and multi-vendor compatibility of equipment [8, 9].
- On a regulatory level there is a lack of market rules for infrastructure investments and ownership as well as a lack of regulation regarding the operation and management of these grids from the legal, technical and market point of view [8]. Furthermore, additional barriers are linked specifically to the regulation of an HVDC MOG (e.g. control issues).

The PROMOTioN project hypothesises that current projections for offshore wind deployment to 2050 could be delivered more economically via a meshed offshore transmission system, as opposed to radial connections to shore for each wind farm as is common today. The CBA will test this hypothesis and inform the development of

[5] A separate WP once also studied Diode Rectifier Units, but this WP was terminated during the project.
[6] North Sea, Irish Sea, English Channel, Skagerrak Strait and Kattegat Bay
[7] This is based on methodology from the European Network of Transmission System Operators for Electricity, modified for the evaluation of a full grid rather than for incremental improvement of existing grids.
[8] For a full overview of research studies that deal with similar topics, refer to Section 2.3.

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the offshore grid roadmap in Deliverable 12.4 by highlighting the range of circumstances under which different grid deployment strategies are favoured.

This Deliverable is structured as follows:

- Chapter introduces the different scenarios, concepts and the CBA method,
- Chapter 3 defines the three scenarios for offshore wind generation: High, Central and Low,
- Chapter 4 identifies the four different grid development concepts,
- Chapter 5 illustrates the grid topologies[9] that follow from the scenarios and concepts and describes their purpose in the CBA,
- Chapter 6 details the methods and assumptions for the cost section of the CBA,
- Chapter 7 presents the methods and assumptions for the benefit section of the CBA,
- Chapter 8 presents the CBA results,
- Chapter 9 discusses the further development of the applied methodology and suggests further research,
- Chapter 10 summarises the conclusions

- Appendix I provides a more detailed methodology for developing the wind scenarios and is complementary to Chapter 3,
- Appendix II details the optimal transmission expansion problem and is complementary to Chapter 5,
- Appendix III contains the topology results of the Central and Low wind scenarios and is complementary to Chapter 5,
- Appendix VII describes the methodology used for the cost data collection and is complementary to Chapter 6,
- Appendix VIII contains the methodology for the learning curve effect on cost development over the studied period and is complementary to Chapter 6,
- Appendix IV describes the cost calculation results of the Central and Low wind scenarios and is complementary to Chapter 6,
- Appendix V presents the benefit calculation results of the Central and Low wind scenarios and is complementary to Chapter 7,
- Appendix VI includes a qualitative study to benefits of a MOG and is complementary to Chapter 7.

The outcome of this analysis feeds directly into Deliverable 12.3 and Deliverable 12.4, which are the draft and final roadmap for the deployment of the offshore grid. The deployment plan (DP) will translate the work presented in this document into tangible actions and recommendations. As the CBA does not provide a definitive 'optimal' concept, this development plan is described as concept agnostic wherever possible. Where necessary, it is highlighted where concept-specific choices will have to be made and the costs and benefits of this choice are described.

[9] Topology is the way in which constituent parts are interrelated or arranged. It describes where OWFs are located and how the transmission network is designed. In the context of PROMOTioN, a topology is used to describe a particular concept under a certain offshore wind deployment scenario.

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2 EUROPEAN OFFSHORE GRID DEVELOPMENT - ESTABLISHING THE BASIS FOR A COST-BENEFIT ANALYSIS

2.1 SUMMARY OF THE CHAPTER

Development of offshore wind energy is growing rapidly, but the exact pace at which development will take place is dependent on numerous factors including the economic case for offshore wind, environmental constraints and capacity in the supply chain. To account for this uncertainty, the PROMOTioN project' has considered three different deployment scenarios for the North Seas for 2050 - Low (90 GW), Medium (150 GW) and High (205 GW). Each scenario is developed in five year time steps. The PROMOTioN project has also developed four grid development concepts to describe the different ways in which the offshore transmission grid could develop out to 2050.

A CBA provides a structured means of assessing and comparing the net benefit to society of these different concepts under different offshore wind deployment scenarios. Demonstrating the cost effectiveness of a solution to harness these resources is a fundamental requirement to unlock the full potential of Europe's offshore resources in the North Seas. It is an assessment of the costs and benefits of an investment decision in order to assess the welfare change attributable to it [10] and a decision support tool used to judge the advantages and disadvantages of an investment decision (or series of investment decisions).

This Chapter introduces the deployment scenarios and concepts used to build the grid topologies, it provides an overview of the boundaries of the CBA methodology developed in Work Package 7 and the Key Performance Indicators (KPIs) used to compare different topologies. Each of these topics is described in more detail in subsequent Chapters or, in the case of the CBA methodology, in Deliverable 7.11.

This Chapter then highlights the findings from previous offshore grid studies and the remaining barriers to MOG deployment identified within the PROMOTioN project. Finally, the Chapter summarises the scope of the other PROMOTioN WPs and the extent to which their findings have influenced the design of the grid topologies and CBA process.

2.2 INTRODUCTION

2.2.1 THE DEVELOPMENT OF THE PROMOTION COST-BENEFIT ANALYSIS METHODOLOGY

A CBA is an assessment of the costs and benefits of an investment decision in order to assess the welfare change attributable to it [10] and a decision support tool used to judge the advantages and disadvantages of an investment decision (or series of investment decisions). The development of the CBA methodology used in the PROMOTioN project is detailed in Deliverable 7.11 and provides the basis for the assessment of costs and benefits in Chapters 6 and 7 respectively. The combined analysis is carried out in Chapter 8.

Deliverable 7.11 sets out the KPIs against which each proposed offshore concept design is assessed, and describes two ways of measuring each of these:

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- An ideal methodology which would provide a more accurate reflection of the costs and benefits but would be more time consuming and onerous to undertake. There is also a risk that a large number of the data points for the ideal CBA would not exist.
- A practical CBA methodology which enables the assessment of each KPI within the scope and time constraints of the project.

The PROMOTioN project has used the practical CBA methodology. The KPIs used are described in Section 2.2.4. The aim of the practical CBA is to quantify and monetise the KPIs as much as possible. Where this is not possible, or robust, a combination of quantitative and qualitative assessments can be made (hybrid CBAs). Direct project comparison then becomes less straightforward, but the use of appropriate assessment criteria and methodologies results in an outcome which is a more useful CBA for decision making.

The CBA methodology has been applied to each of the four concepts under each of the three offshore wind deployment scenarios. A separate grid topology has been developed for each five year time step from 2025 to 2050. This means that in total 72 different topologies have been developed and were assessed as part of the CBA. The CBA results have been used to highlight differences between concepts, rather than select a single 'best' option. The offshore wind deployment scenarios and concepts are introduced below with further details on these and the method used to develop the topologies provided in Chapters 3, 4 and 5 respectively.

2.2.2 AN INTRODUCTION TO THE OFFSHORE WIND DEPLOYMENT SCENARIOS

The rate of deployment of offshore wind is inherently uncertain. To account for this uncertainty, the PROMOTioN project's CBA has considered three different deployment scenarios for the North Seas for 2050 – Low wind deployment (90 GW), Medium wind deployment (150 GW) and High wind deployment (205 GW) by 2050. Each scenario is developed in five year time steps. These scenarios were adapted from the European Network of Transmission System Operators for Electricity (ENTSO-E) Ten Year Network Development Plan (TYNDP) 2018 forecasts to 2045 [2].

Table 2-1 below provides an overview of the three deployment scenarios; further detail on how these scenarios are derived and allocated is provided in Chapter 3.

Table 2-1 - Overview of three deployment scenarios used in PROMOTioN (values in GW).

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

2.2.3 AN INTRODUCTION TO THE CONCEPTS AND TOPOLOGY DEVELOPMENT

The PROMOTioN project has developed four grid development concepts to describe the different ways in which the offshore transmission grid could develop out to 2050. **Error! Reference source not found.** below provides a simplified representation of each concept.

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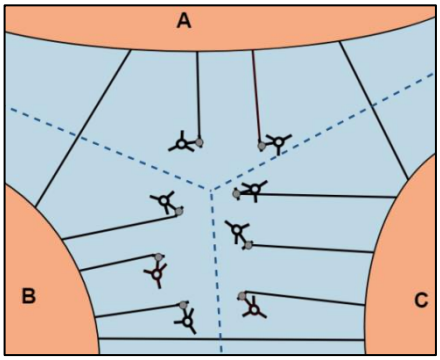
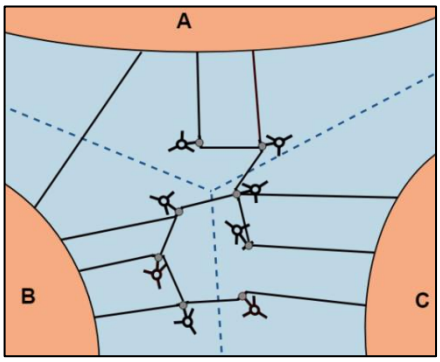


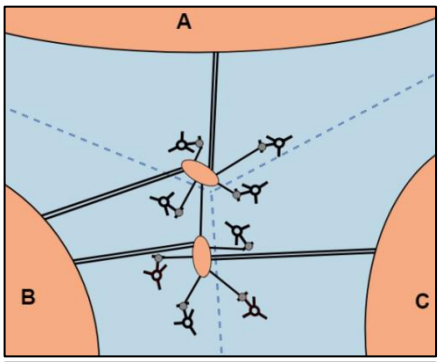
Business as usual (BAU)

The offshore wind farms (OWFs) continue to get connected radially to the grid. This may be in separate point-to-point connections, but some OWFs might also be bundled to reach a critical size of 2 GW. This standardised 2 GW concept utilises the most current HVDC equipment and is therefore the continuation of a near-future high-end concept. Power exchange between countries is facilitated by separate point-to-point interconnection.



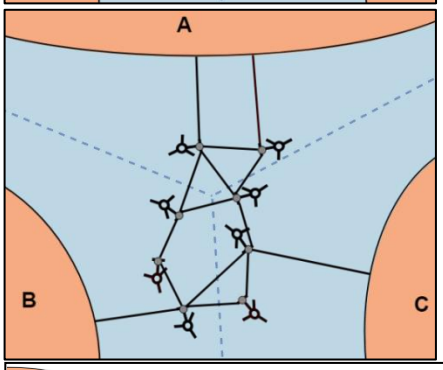
National Distributed Hubs (NAT)

This concept is based on a national approach to offshore grid construction. The purpose 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 cooperation 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 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.

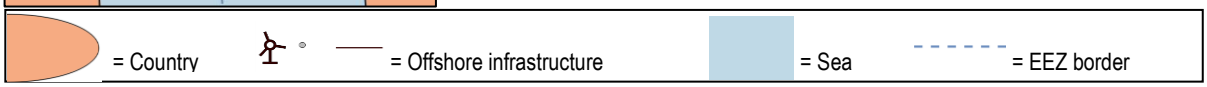


Figure 2-1 - Illustration of the different concepts.

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2.2.4 COST-BENEFIT ANALYSIS - KEY PERFORMANCE INDICATORS

The CBA methodology developed for PROMOTioN builds on existing methodologies used to assess offshore wind investments, in particular that used by the ENTSO-E. The PROMOTioN methodology identified the set of KPIs described in Table 2-2 below. These KPIs can be used to compare all project alternatives in a transparent manner.

Table 2-2 - KPIs considered for the PROMOTioN CBA.

#	NAME	DESCRIPTION
Costs		
C1 & C2	CAPEX and OPEX	The capital expenditure (CAPEX) associated with the preparation, design, fabrication and construction the offshore transmission network and the operational expenditures (OPEX) associated with the operation of this network during the researched period. The onshore grid reinforcement requirements are not calculated within PROMOTioN.
Benefits		
B1	Socio-Economic Welfare	Increased interconnection resulting from a MOG leads to wholesale price convergence. In this instance the change in socio-economic welfare is the sum of the consumer (demand) surplus, the producer (generator) surplus and congestion rents (where applicable). Increased interconnection may also reduce system balancing costs across North Seas countries.
B2	RES Integration	The effectiveness of each concept in integrating renewable energy sources (RES) is measured by analysing the curtailment of renewable energy sources.
B3	CO_2 Variations	This KPI measures the difference in CO_2 emissions as a result of offshore wind energy integration.
B4	Societal Well-being	Many of the societal well-being benefits are captured in B1 and B3. This category is concerned with the benefits that do not directly fall under those benefit categories, such as decreased onshore reinforcement requirements in a meshed versus radial configuration.
B5	Grid losses	The system modelling undertaken for the CBA will calculate the change in grid losses (onshore and offshore) as a result of different concepts.

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#	NAME	DESCRIPTION
B6	Security of Supply – Adequacy	Adequacy of a power system can be defined as its ability to satisfy the consumer demand and system's operational constraints at any time, in the presence of scheduled and unscheduled outages of generation and transmission components or facilities. This KPI is measured in terms of the expected energy not transported due to outages of transmission components. In an offshore grid, greater offshore meshing provides greater system redundancy and alternative paths for offshore wind evacuation and trade.
B7	Security of Supply – Flexibility	Two measures of flexibility are considered – the increase in alternative paths for energy evacuation as a result of greater meshing, and the smoothing of generation profiles as more intermittent generators are connected across a wide geographical region.
B8	Security of Supply – Security	This KPI considers the extent to which the transmission system can cope with disturbances applied to it. The main differentiator between meshed and radial configurations is that meshed networks will have greater access to restoration (black start) capabilities across the network.
B9	Security of Supply – Resilience	This KPI measures the ability of the grid to withstand physical or cyber-attacks and natural disasters such as earthquakes and storms.
Social Factors		
S1	Environment	This KPI measures the amount of equipment needed to build each concept (cable length, number of platforms etc.), assuming that the higher the amount of equipment deployed, the greater the environmental impact.
S2	Social	This KPI measures the impact of building the grid on, specifically, the coastal population. It is assumed that the higher the number of onshore connections, the greater the negative impact.
S3	Other	Other factors that are not previously included. These could be factors like increased sustainability, geopolitical independence or increased European cooperation.

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2.2.4.1 BOUNDARIES

The scope of the CBA is set out in detail in Deliverable 7.11. Table 2-3 provides a summary of the boundaries set.

Table 2-3 - Key boundaries of the CBA methodology.

ITEM	DECISION	COMMENT
Scope of CBA	Societal value of each offshore concept	Whilst the CBA will calculate total societal value, political acceptance of a MOG will depend on the relative benefits to each country, not just the overall societal benefit.
Type of CBA	Augmented CBA (considering both monetised and non-monetised KPIs)	Whilst each KPI will be scored and weighted, in some cases this will follow a qualitative analysis and comparison of costs and benefits
Purpose of the project	To evacuate all of the planned offshore wind energy in the offshore area to shore (the design will not include curtailment) *and* to increase market integration.	In reality, it may be cost effective to curtail a small percentage of offshore wind production as the cost of extending the transmission network to evacuate this generation exceeds the benefit.
Sectors covered by CBA	OWFs connected to offshore transmission networks	No offshore energy storage is assumed in any of the topologies; PROMOTioN does not consider offshore Power-to-Gas. It is assumed that all electricity generated can be transmitted to shore (see above). This assumption could result in the topologies having larger transmission capacity than would be installed if offshore power to gas were deployed. In reality, the likelihood of offshore Power-to-Gas or other large scale storage deployment should be considered as part of an investment business case to avoid excessive anticipatory investment.
Geographical scope of the CBA	The topologies encompass the offshore grid infrastructure, including connection points with OWFs and the near-shore onshore grid.	The CBA does not consider the need for onshore transmission reinforcements. Whilst it is noted that for some countries expected offshore wind peak generation will exceed peak demand, it is assumed that all evacuated energy can be absorbed by the onshore grid. For clarity, PROMOTioN has assumed costs of transmission to onshore nodes close to the landing points. There are no calculations made for reinforcement of the onshore grid or for long distance onshore transport to centres of consumption.

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ITEM	DECISION	COMMENT
Technology choices within each topology	Each topology will use the most appropriate combination of grid technologies	For clarity, one topology will be developed for each combination of offshore wind deployment scenario and concept at each five-year time step to 2050.
Representation of the onshore market model	Zonal (per bidding zone)	Each bidding zone in the onshore area is represented by a single node. This simplification is necessary to allow the electricity system to be modelled within the time constraints available. This assumes that there is no congestion within a bidding zone. In reality this is not always the case (for example, there are constraints between North and South Germany and historically between Scotland and England, although the HVDC Western Link cable has gone someway to relieving these).
Representation of the offshore market model	One design appropriate to each concept	In theory, if the markets work efficiently, then the electricity will always flow to the higher priced market – be it through connection to shore and then an interconnector or directly. Further discussion on this topic and on the efficiency of the market model may be found in Deliverable 12.4.

In addition to the boundaries set out in Table 2-3 and in Deliverable 7.11, additional technical assumptions have been made to enable the transmission system to be modelled for the CBA. These assumptions are listed below and described in more detail in Chapter 4 and in Deliverable 12.4.

- There are no offshore loads (e.g. demand from offshore platforms) to be met.
- The system modelling does not include onshore distributed energy storage of any kind. However, it should be noted that, in reality, onshore energy storage is anticipated to increase the ability of the onshore grid to accept wind generation.
- The three offshore wind deployment scenarios are the same across all four concepts, i.e. the concept does not influence where or when OWFs are built.
- The offshore grid does not disrupt the onshore grid, i.e. the design will comply with limits on largest infeed losses in each North Seas' country and will not result in any load shedding onshore.

Finally, it should be reiterated that it is not the intention of the CBA to select a single 'best' design for an offshore transmission network in the North Seas, but rather to explore the value of each concept under different deployment scenarios. In reality, the network may develop as a combination of two or more design concepts. The value of examining distinct design concepts in five-year time steps is that it identifies the point at which different concepts diverge in their development. This can help identify key decision points in the development of an offshore grid which will be fed into the Deliverable 12.4 roadmap.

2.3 DESCRIPTION OF PREVIOUSLY PERFORMED STUDIES

Several previous studies have already addressed the development of offshore meshed HVDC grids and the associated technical challenges and regulatory and financial barriers. Deliverable 1.3 – *Synthesis of available*

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studies on offshore meshed HVDC grids gives a comprehensive oversight of previous EU studies such as Twenties, Irish-Scottish Links on Energy Study (ISLES), North Seas Countries' Offshore Grid Initiative (NSCOGI) and E-Highway 2050.

As such, at first glance it might seem superfluous to yet again spend time to perform more research on this subject. However, Deliverable 1.3, written in 2016, found that the exact geographical scopes, methodologies and assumptions can differ strongly from one study to another. Moreover, very different levels of detail are used to model power systems: from macro-levels, modelling only transfer capacities between hubs, to node-breaker models. It is therefore the purpose of this Section is to highlight similarities and differences of the PROMOTioN project in relation to other projects, in order to show the merit of the project.

Table 2-4 and Table 2-5 compare the technical and non-technical scope of the PROMOTioN project to the scope of previously completed studies. A short summary of each study is included below. Many of these studies are examined in more detail in Deliverable 1.3. It can be seen that although many different studies have focused on the same non-technical sides of the MOG, many of these studies did not combine a non-technical and technical focus as PROMOTioN did. Additionally, many of the technical areas are unexplored in the different studies.

Nevertheless, some trends emerge from the analysis of these past roadmaps. Firstly, an assessment of previous studies suggested that it is unlikely that the North Seas offshore transmission network will result in a single large interconnected offshore grid: radially connected OWFs and several interconnected grids will coexist. Secondly, as offshore wind deployment levels increase, more complex offshore topologies (i.e. radial multi-terminal and meshed grids) become more cost-efficient than purely radial configurations (Section 2.3, Deliverable 1.3).

Of the more recent studies and projects, which have run (or are running) in parallel to the PROMOTioN project, it is worth highlighting the Kriegers Flak project - the first European project which proposes connecting OWFs with an interconnector between Germany and Denmark[10]. This *hybrid* asset (both an interconnector and a route to shore for the OWFs) will be an important test case of both the technical capabilities of hybrid assets and how they are regulated.

Table 2-4 - Scope of non-technical studies into meshed offshore grids.

STUDY	COMPLETED	L&R[1]	GOV[2]	FIN[3]	ECON[4]	MAR[5]	ENV[6]	MSP[7]	SME [8]
PROMOTioN	Dec-19	■	■	■	■	■	■		
NSCOGI	Jan-10	■	■	■	■	■	■	■	
ISLES	Jan-11	■		■			■	■	
WindSpeed	Jun-11								
Roland Berger	Jul-11		■	■		■			
EirGrid	Aug-11	■						■	
OffshoreGrid	Oct-11	■		■		■	■	■	

[10] German onshore grid – German OWF – Interconnector – Danish OWF – Danish onshore grid

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STUDY	COMPLETED	L&R[1]	GOV[2]	FIN[3]	ECON[4]	MAR[5]	ENV[6]	MSP[7]	SME [8]
Twenties	Dec-13	■		■		■		■	
NorthSeaGrid	Apr-15	■		■				■	
E-highway 2050	Dec-15	■		■				■	
Tractebel/Ecofys/PwC	Jan-16	■		■	■	■	■	■	
Kriegers Flak	Mar-18				■		■		
ENTSO-E TYNDP	Oct-18			■	■		■		
Baltic Integrid	Mar-19	■			■		■	■	■

[1] Legal and regulatory – the legal definitions and agreements required to establish the legal and regulatory basis for meshed offshore transmission networks

[2] Governmental – Policy decisions necessary to facilitate offshore wind capacity growth and meshed offshore transmission networks

[3] Finance and governance – The financial framework necessary to attract investment in meshed offshore transmission networks. This is closely linked to regulation.

[4] Economics and CBA – An assessment of the societal value of different transmission network configurations, both meshed and radial.

[5] Markets – How energy is valued and traded in a meshed offshore network

[6] Environment – The relative impact of different offshore transmission network configurations on greenhouse gas emissions and wider environmental impacts (habitat disturbance etc.).

[7] Marine Spatial Planning – Decisions on where new OWFs and transmission assets should be sited and the process for determining this.

[8] Supply chain and Small and Medium Enterprise investment – The implications of different network configurations for the supply chain and opportunities for Small and Medium Enterprises to contribute.

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Table 2-5 - Scope of technical studies into meshed offshore grids.

STUDY	COMPLETED	DRU[1]	VSC[2]	CS[3]	WTG-C[4]	GP[5]	DC CBS – T[6]	DCCBS[7]	MTDC[8]	GP – D[9]	DCCB – D[10]	GIS[11]	AC/DC[12]	INT[13]	C[14]	DC/DC[15]
PROMOTioN	Dec-19	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■
NSCOGI	Jan-10		■											■		
WindSpeed	Jul-11			■												
EirGrid	Aug-11												■			
OffshoreGrid	Oct-11			■									■		■	
ISLES	Apr-12															
Twenties	Dec-13		■			■	■	■	■	■	■	■	■	■	■	■
Tractebel/ Ecofys/ PwC	Jun-14			■												
NorthSeaGrid	Apr-15															
Muller PhD thesis	Sep-15															
E-highway	Dec-15															
Kriegers Flak CGS	Mar-18												■		■	
Best Paths	Sep-18		■	■	■								■	■	■	■
ENTSO-E TYNDP (2018)	Dec-18															

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STUDY	COMPLETED	DRU[1]	VSC[2]	CS[3]	WTG-C[4]	GP[5]	DC CBS – T[6]	DCCBS[7]	MTDC[8]	GP – D[9]	DCCB – D[10]	GIS[11]	AC/DC[12]	INT[13]	C[14]	DC/DC[15]
Roland Berger	Mar-19															
Baltic Integrid	Mar-19															
Migrate	Dec-19															

[1] Diode rectifier unit (DRU) – A means of converting AC into Direct Current (DC). DRUs are typically smaller and more lightweight than regular converters and may therefore significantly reduce the cost of offshore platforms. Its use in meshed situations is, however, still uncertain.

[2] Voltage Source Converter (VSC) – A voltage source converter converts AC into DC or vice versa.

[3] Control systems and grid topology – A topology represents the layout of the network and how generation and demand are connected. Different configurations will require different strategies to control power flows in a stable situation and manage any faults which occur

[4] Wind Turbine Generator – Converter interaction. Wind turbines generate electricity in AC. They can be connected to a DC network via a DRU or VSC, depending on the purpose of the line. Each combination has implications for control and protection strategies for the wind farm and network.

[5] Grid protection – Strategies for protecting the transmission network from faults, and minimising the impact of faults which do occur.

[6] HVDC Circuit Breakers test environment - Testing facilities and protocols for HVDC Circuit Breakers

[7] DC Circuit Breaker – A circuit breaker is a switch which protects electrical systems by breaking the circuit when a fault (e.g. current overload) is detected.

[8] Multi-Terminal DC lab demonstration – Testing facilities to simulate meshed DC networks connecting more than two points.

[9] DC grid protection demonstration

[10] Circuit Breaker performance demonstration

[11] Gas Insulated Switchgear – Switchgear is used to isolate electrical equipment. This allows work to be completed on electrical equipment and can help to clear faults on part of the network.

[12] AC/DC interaction

[13] Interoperability – The ability for different components in an electrical system to work together. This includes consideration of whether equipment from different manufacturers could operate within the same network.

[14] Cables

[15] DC/DC converters – A device to convert DC from one voltage level to another.

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A description of each of the studies listed in the tables above is presented below:

NSCOGI (North Sea Countries' Offshore Grid Initiative): a regional cooperation of 10 countries to facilitate the coordinated development of a possible offshore electricity grid in the greater North Sea area. Seeks to maximise the efficient and economic use of renewable energy resources as well as infrastructure investments. NSCOGI is subdivided in Working Groups, concerning Grid configuration (Working Group 1), Regulatory issues (Working Group 2) and Planning and Permitting (Working Group 3).

ISLES (The Irish-Scottish Links on Energy Study): a project commissioned by the governments of Scotland, Northern Ireland and Ireland, that investigated in detail the opportunities and challenges in developing a cross-jurisdictional offshore transmission network that connects large-scale offshore marine generation, provides for enhanced interconnection and facilitates additional onshore grid and electricity market benefits.

WindSpeed: the work programme of the project covers the full chain from data and policy inventory, methodology development, to scenario and roadmap definition. The techno-economic work packages are: inventory of offshore wind potential and related infrastructure; inventory of current and future presence of other sea functions and identification of interactions; methodology and tools; scenario development and roadmaps. The project assumed that DCCBs were needed when using the VSC technology, but there was at that moment a high uncertainty on the cost of such circuit breakers and related switch gear.

Roland Berger study 2011: a study on the structuring and financing of energy infrastructure projects, the financing gaps and recommendations regarding the offshore grid. Set off to answers three questions

- What was the structure of energy transmission infrastructure investments in the last five years in terms of investment volumes, financing structures, financing sources and the financing capacity of operators, and what do we expect to see in the future?
- What challenges arise regarding the financing of such infrastructure projects, and where are the financing gaps?
- What measures and instruments should be implemented to overcome such challenges and gaps?

EirGrid: a study to develop a vision for an offshore grid in the Irish Sea. Three offshore wind generation scenarios out to 2030 were developed. For each scenario, the offshore grid topology and reinforcements in onshore grid were optimised on the basis of a formal optimal transmission expansion planning problem, to minimise the combined cost of power production and network development. The development of the grid is analysed for three target years: 2020, 2025 and 2030. In this way, the commissioning schedule of the new transmission elements could be drafted.

OffshoreGrid: considered the possible use of six different HVDC converters: three Current Source Converter (CSC) types and three VSC types. The methodology used on the offshore grid designs has been to use DC fault isolation equipment (such as DCCBs) to prevent any power infeed loss to onshore AC transmission systems exceeding the amount of frequency control reserve held by the onshore system. Even if DCCBs were not commercially available at that moment, the project assumed thus the availability of adequate DCCBs in the near future, based on discussions with manufacturers.

Twenties: the project studied offshore grid design in the North Seas. The aim was the demonstration of the

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benefits and impacts of several critical technologies required to respond to the increasing share of renewable energy in the pan-European transmission network by 2020 and beyond.

NorthSeaGrid: the focus of the projects is interconnectors that directly integrate OWFs. Rather than investigating the overall power system, the project looks at the barriers that hinder the implementation of interconnectors and focus on three concrete, carefully selected case studies. The aims of the project are: to identify the main challenges, risks and financial effects for various stakeholders; to calculate costs and benefits based on sensitivities and risk assessments; to identify approaches for the cross-border allocation of costs and benefits; to propose changes to regulatory frameworks; to prepare recommendations to facilitate the implementation of the first integrated offshore grid solution.

E-highway: This project is aimed at developing a methodology to support the planning of the Pan-European Transmission Network, focusing on 2020 and 2050, to ensure the reliable delivery of renewable electricity and pan-European market integration. A database of the status of technologies required for meshed HVDC networks was created. For each kind of HVDC technology (i.e. CSC and VSC), a list of critical techno-economic parameters was identified. For each parameter, values were gathered from a literature review and from the expertise of the project partners. Cost and performance trajectories from today to 2050 were defined.

Tractebel/Ecofys/PwC study for the EC (Study on the regulatory matters concerning the development of the North and Irish Sea offshore energy potential): the study aimed to identify and understand the existing regulatory barriers obstructing offshore grid development. Apart from the barriers, it aimed to develop a set of workable models and identify and sequence the legal, regulatory and policy activities to implement the suitable regulatory models.

Tractebel/Ecofys/PwC study for the EC (Study of the benefits of a Meshed Offshore Grid in Northern Seas Region): the goal of the study is to assess the full suite of potential benefits of a meshed offshore electricity grid in the North Sea, the Irish Sea and the English Channel out to 2030 for a comprehensive range of scenarios. A key objective is to estimate the benefits of the meshed grid as compared to those for radial offshore generation connection.

Kriegers Flak: the study describes the overall infrastructure of the Kriegers Flak Combined Grid Solution and the master controller for interconnector operation functions. A model-based evaluation of those shows the behaviour of the HVAC/HVDC meshed submarine grid in normal operation and in the case of contingencies.

ENTSO-E TYNDP (2018) (Northern Seas Offshore Grid): addressed the development of electricity grid infrastructure in the geographical area covered by the Northern Seas offshore grid (Regulation 347/2013). It highlights three main boundaries in the Northern Seas offshore grid region where additional reinforcement is particularly beneficial. The boundaries are: Ireland to Great Britain and Continental Europe – Great Britain to Continental Europe and Nordics; and Nordics to Continental West Europe.

Roland Berger 2019: A study of hybrid projects: How to reduce costs and space of offshore development. Examines the various planned potentially hybrid projects and how the implementation of HVDC meshing technology can improve these projects. The study also describes the legal & regulatory actions and governmental change/requirements for these projects to go ahead.

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Baltic Integrid: the project has been developing a professional network and providing for a for expertise exchange and state-of-the-art interdisciplinary research on the optimisation potential of offshore wind energy in the Baltic Sea Region by applying the meshed grid approach. The project aims to contribute to a sustainable electricity generation, the further integration of regional electricity markets, and to enhance the security of supply around the Baltic Sea.

H. K. Mueller's PhD thesis (A legal framework for a transnational offshore grid in the North Sea): assessed existing legal frameworks relevant in the view of offshore grid development. In this perspective, distinction is made between international, European Union and national law. It includes the current legal and regulatory barriers for the transnational offshore grid development. Recommendations are made to overcome these barriers..

Best Paths: the project unites expert partners around five large-scale demonstrations to validate the technical feasibility, costs, impacts and benefits of the tested grid technologies. The focus of the demonstration is to deliver solutions to allow for transition from HVDC lines to HVDC grids, to upgrade and repower existing AC parts of the network, and to integrate superconducting high power DC links within AC meshed networks.

Migrate: the objective of MIGRATE is to develop and validate innovative, technology-based solutions in view of managing the pan-European electricity system experiencing a proliferation of Power Electronics devices involved in connecting generation and consumption sites

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2.4 INPUT FROM OTHER WORK PACKAGES

The focus of the PROMOTioN project has been to remove the remaining technical, legal, regulatory, financial and economic barriers to delivering a MOG in the North Seas. A thorough analysis of the remaining barriers to MOGs was carried out in Deliverable 1.1 – *Detailed description of the requirements that can be expected per work package*. It identified 124 qualitative requirements which must be met in order for a MOG to be developed successfully. The requirements are grouped by system or interface as follows (number of requirements identified in brackets):

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

Figure 2-2 summarises how each group of requirements relates to the PROMOTioN WPs. Further details can be found in Deliverable 1.1.

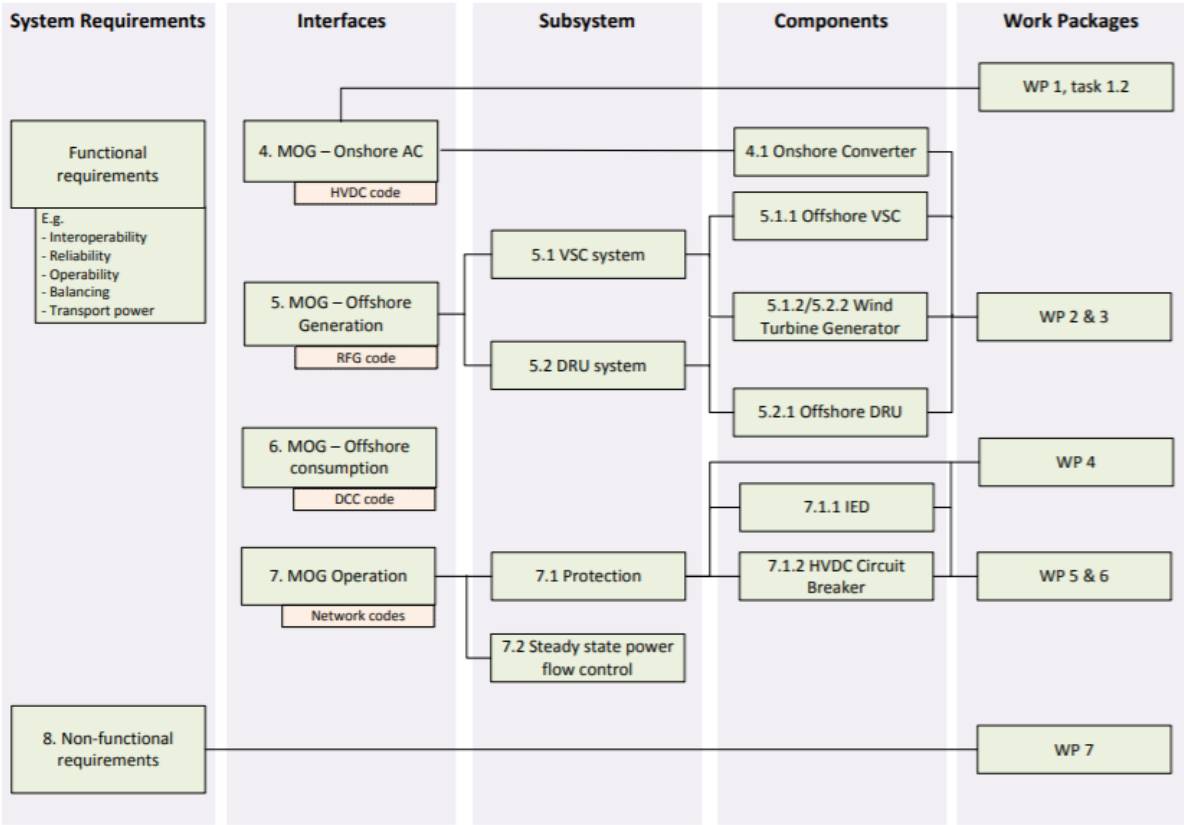

Figure 2-2 - Requirements for large meshed offshore grids.

This Section provides a high-level overview of the focus of each WP and how this contributes towards meeting the requirements of an offshore grid. This Section also comments on whether a WP has influenced the design of the concepts and topologies used in the PROMOTioN CBA. Further details can be found in the deliverables of

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each WP. An overview of the WPs is shown in Figure 2-3, where it can be seen that the requirements of WP1 are allocated to WP2 through 7[11], and flow on into WP12.

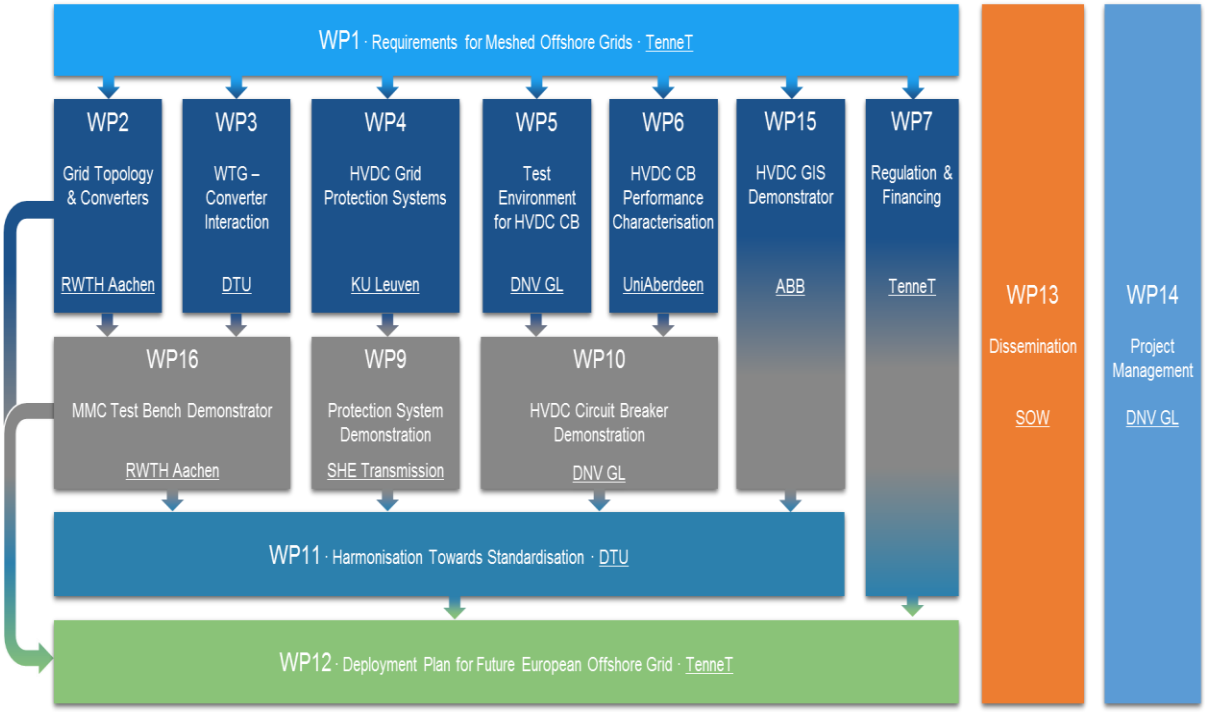

Figure 2-3 - Overview of the Work Packages in the PROMOTioN Project.

2.4.1 TECHNICAL WORK PACKAGES

2.4.1.1 WORK PACKAGES 2, 3 AND 16: GRID TOPOLOGY, WIND TURBINE GENERATOR - CONVERTER INTERACTIONS AND CONTROL SYSTEMS

Overview

A key objective of WPs 2, 3 and 16 is to develop control systems which ensure the interoperability of different components in a multi-terminal (meshed) offshore and onshore grid. At the time of writing, these WPs have identified several challenges associated with operating a MOG and have proposed solutions or highlighted the need for further work. The research carried out in WPs 2 and 3 is feeding into WP16 – a test bench demonstration which will investigate the controllability of HVDC MOGs and their interoperability with onshore AC networks. A key output from these three WPs will be recommendations on the operation of the HVDC network, including a series of recommendations for changes to grid codes for onshore and offshore power systems.

In addition, the successful completion of WP3, which has focused on managing interactions between wind turbines and converters, will increase the Technology Readiness Level[12] (TRL) of grid forming controls for wind turbines to TRL 7.

[11] WP15 was added at a later stage, after D1.1 was already completed.
[12] The Technology Readiness Level estimates the maturity of technologies, ranging from a basic idea (TRL 1) to an actual proven system with competitive manufacturing (TRL 9)

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Further Details – Work Package 2

One of the key advantages of multi-terminal systems with the option to mesh is the increased redundancy in the system in case of a line outage. A high availability of the grid is needed when considering structures integrating several GW of installed wind power. In case of a line fault, the connected wind power plants have to be able to ride through the fault. In WP2, the requirements on this fault ride through behaviour of the wind farms were investigated for different DC fault clearing strategies and the wind farm controls enhanced to allow a smooth ride through. In addition, the provision of ancillary services (in this case, frequency support) by the HVDC grid was investigated. Moreover, the integration of DRUs as the offshore converter were analysed in a broad range of topologies and scenarios to validate its applicability in multi-terminal HVDC systems. This found that DRUs could be integrated into different concepts.

The research in WP2 focused on demonstrating fault clearing strategies on smaller meshed grids with converters at each busbar. The technical investigations focused on symmetric monopoles as they are used for wind power integration today. Further research may be required if the planned topology and configuration includes additional controls or equipment which were not in the scope of PROMOTioN.

Impact on CBA topologies – WP 2, 3 and 16

Recommendations from these WPs have informed topology development. In particular, recommendations from WP2 to avoid radial DC connections of wind farms to the busbar of a DC node and to avoid interconnection of all offshore windfarms to one grid have been taken into account. Additionally, WP2 stressed that interconnecting converters on the DC side on an island is unfavourable as this does not provide control over the power flows.

WP2 and 3 have tested the integration of DRUs into MOG. Whilst WP2 found that DRUs can be integrated into the concepts and WP3 has simulated a proof-of-concept for connecting and controlling wind turbines using DRUs, DRUs have not been included in the CBA topologies. This decision was made by the PROMOTioN consortium in 2018. This decision was made because DRUs have not proven to be able to operate with a bidirectional flow, meaning they cannot be applied in meshed situations. The concepts can only be fairly compared if the same technologies can be applied in each of these and thus it was chosen to not include DRUs in the cost estimation of the CBA.

The test bench demonstrations in WP16 will look at smaller network dimensions (a four terminal HVDC network) than the topologies considered in WP12. When WP16 comes to a close, recommendations will be provided for the operation of the HVDC network based on the demonstrations. Because of the expected minor difference in scale, the recommendations are unlikely to distinguish between the National and European Distributed network concepts. It should be noted that, at the time of writing, it is not planned to demonstrate the European Centralised network.

2.4.1.2 WORK PACKAGES 4 AND 9: HVDC GRID PROTECTION SYSTEMS

Meshed HVDC networks require unique protection systems. Isolating faults on a point-to-point DC connection has been commercially demonstrated, but meshed DC networks are novel and more complex in terms of their protection requirements. The technologies that could be used to protect DC networks are themselves under

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development (e.g. DRUs, VCSs, DCCBs and Gas-Insulated Switchgear), therefore this work package has had to consider a number of different technology and topology configurations.

The overarching objective of WP4 is to develop a set of functional protection requirements for various DC grids, from small scale networks, to large meshed grids using a variety of system configurations and converter technologies.

The methodology followed in this WP has been to:

- Analyse a wide range of DC grid protection philosophies on a common set of metrics.
- Identify the best performing methods for the systems under study.
- Develop detailed protection methodologies for the selected methods.
- Develop configurable multi-purpose HVDC protection Intelligent Electronic Devices to enable testing of the methodologies

To date, WP4 has shown that large systems can be effectively protected using different possible approaches. The final stage of WP4 will investigate the key influencing parameters of protection systems on the CBA. Therefore, the results of this WP did not impact the design of the topologies, but will influence the CBA results of each topology.

2.4.1.3 WORK PACKAGES 5, 6 AND 10: DEVELOPMENT OF HVDC CIRCUIT BREAKERS

HVDC circuit breakers are an important component of a cost-effective MOG. The objective of WP5 has been to develop the requirements of a DCCB test programme and to create test procedures and methods for verifying their performance. These methods will be applied to three full-scale prototype circuit breakers in WP10:

- A multiple-unit breaker with active current injection
- A multiple-unit breaker with VSC assisted resonant current
- A full hybrid type of DCCB

Successful completion of these full-scale prototype tests (which will be independently verified) will demonstrate that DCCBs can isolate faulted branches of a meshed grid topology. This will increase their TRL to 7 and make DCCBs available for future deployment in a real HVDC network[13].

In parallel, WP6 has characterised the DCCBs currently available on the EU market. This has led to recommendations for cost reductions and performance improvement in future DCCBs. WP6 has also worked with circuit breaker manufacturers to identify areas suitable for technology standardisation.

WP6 has also examined the operating speed of DCCBs and their impact on the security of power supply across the grid. WP6 and WP4 have worked together to understand DCCB performance and the protection strategies needed to ensure the offshore grid can operate in a way which limits the maximum infeed loss to any one country (onshore) based on its current limits.

Impact on topologies

[13] However, it should be noted that the requirements for testing have been defined and agreed with partners in the PROMOTioN project. Transmission grid developers may require a slightly different specification which would require additional testing.

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The progress made by WPs 5 and 10 is an enabling step for any concept or topology that is likely to require

DCCBs - in the context of the CBA this includes the NAT, HUB and EUR concepts. Had WP5 concluded that it is not possible, or not economically viable, to test DCCBs adequately (prior to their deployment in a real HVDC network), this would have changed how they could be applied in HVDC networks. This would have impacted the topology built, as a meshed configuration would then be less likely to be economically viable (albeit not completely ruled out). Also, the fault clearing strategy applied would be impacted as the DCCBs would have been considered to be less reliable, so more back-up protection and increased redundancy would need to be designed into the network to manage the higher number of failures and longer downtime expected.

In addition, the topologies have been developed to limit the maximum infeed loss to any North Seas' country based on current limits (e.g. 1.8 GW in the UK).

2.4.1.4 WORK PACKAGE 15: HVDC GAS INSULATED SWITCHGEAR DEMONSTRATION

HVDC Gas-Insulated Switchgear is not a pre-requisite for any of the topologies considered in the CBA. However, HVDC Gas-Insulated Switchgear reduces the amount of space required for switchgear equipment, which lowers the required offshore platform volume, and therefore the cost. The use of HVDC Gas-Insulated Switchgear also introduces the option of multi-busbar and switching stations offshore. Therefore, the difference in cost between using Air-Insulated Switchgear and Gas-Insulated Switchgear will have an impact on the cost inputs into the CBA[14], and influence the recommendations in the deployment plan.

To date, WP15 has demonstrated that HVDC Gas-Insulated Switchgear can operate in a meshed grid setting. The next step is a full-scale prototype test which, if successful, would increase the TRL from 6 to 8.

2.4.1.5 WORK PACKAGE 11: HARMONISATION TOWARDS STANDARDISATION

Whilst not strictly a technical work package, the purpose of WP11 is to collate the technical findings from other PROMOTioN WPs and distil these into recommended updates to existing technical standards which can be applied across all offshore transmission and generation assets within the North Seas. This harmonisation of standards is of less importance in a BAU configuration, but is extremely important in any meshed grid configuration. The PROMOTioN project will not draft or implement harmonised standards across all North Seas countries, but will put forwards recommendations for consideration by standards bodies.

Outputs from the technical WPs in PROMOTioN will lead to recommendations in the following areas:

- The technical requirements for components and subsystems to ensure safe and reliable operation
- Methods for testing the performance of assets and/or systems
- Methods for validating compliance with standards

WP11 is ongoing. As it is summarising the results from other work packages, it has not, in itself, influenced the development of the CBA topologies. However, it is stressed that to build a MOG, there is a necessity to agree a number of standards – not least the HVDC voltage. Other agreements are required around standards. As a grid

[14] It is assumed Gas-Insulated Switchgear is applied on all platforms, which means the costs are assumed to be lower than if Air-Insulated Switchgear was applied.

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develops, it will be inevitable that equipment from different manufacturers will need to be connected. This means a divergence from current programmes where a single system may be delivered by a contractor and has performance warranties from that manufacturer. As systems are joined, the interoperability is necessary and cannot compromise these warranties. As such, harmonisation and standardisation are cornerstones to the validation of a CBA.

2.4.2 NON-TECHNICAL WORK PACKAGE

2.4.2.1 WORK PACKAGE 7: REGULATION AND FINANCING

WP7 examines the legal, economic and financial requirements of a MOG. Other than the development of the Business-as-Usual concept, all concepts will require amendments to the legal, regulatory and market frameworks in multiple countries (or at an international level) in order to attract funding for new offshore transmission assets and to ensure that there is a functional market for offshore wind generation.

The societal CBA methodology used in PROMOTioN (and whose findings are presented in this deliverable) was developed in WP7. It is summarised in this document, with further detail available in Deliverable 7.11.

The findings from WP7 have not influenced the technical design of the topologies. Rather, the recommendations from WP7 are intended to be applicable to a range of different concepts, recognising the fact that the actual development of the offshore grid is likely to be a combination of one or more concepts.

The Legal & Regulatory framework can, however, influence the steering of development towards the most desired solutions. The proposals for a "mixed partial agreement", for Hybrid Assets and for a small bidding zones market arrangement all have material impact on the CBA.

The regulatory framework will also influence the level of cooperation between countries, which then indirectly influences choice of concept and eventually capital investment costs.

Proposals for streamlining planning and permit processes are intended to lower the development costs and facilitate anticipatory investments as much as to prepare industry and give security in the future development – thus reducing capital costs and financial costs.

Finally, the finance costs are defined by perceived third party risk. The cost of finance is higher without a stable regulatory environment. Therefore, clarity is required to raise funding.

In the early phases of deployment we anticipate a need for the EU to (partially) fund some of the more risky technologies, to provide solutions to a lack of experience in HVDC grids.

Lastly the sheer capital requirement will require a review by many countries and TSOs as to how to build the correct financial structures and source of funds.

Within Deliverable 12.2, for each concept, it is assumed that an appropriate Legal & Regulatory framework is in place. It was beyond the scope of WP7 to estimate the cost impacts of each Concept and to provide CBA input.

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3 OFFSHORE WIND GENERATION SCENARIOS

3.1 SUMMARY OF THE CHAPTER

Offshore wind generation scenarios out to 2050 represent the range of uncertainty about the evolution of offshore wind energy, and enable a more thorough analysis of how the European offshore grid could develop.

Firstly, three macro-scenarios for the North Seas are defined, giving figures for the various North Seas countries up to 2050. The three scenarios represent a Central estimate as well as two extreme but realistic scenarios (i.e. the High and the Low wind scenario). The national estimates take into account local considerations (e.g. national policies, characteristics of the corresponding power system).

Secondly, these macro-scenarios are translated into OWFs with a specific location and commissioning date. These are allocated using a methodology that takes into account the main technical, economic and environmental criteria used in site selection processes for actual OWFs. These criteria can be divided in two categories: exclusion criteria and selection criteria. Exclusion criteria are those areas that are considered as unsuited for OWF development, such as shipping lanes or extreme water depth (<400m). After the exclusion of these areas, the remaining areas are ranked according to the selection criteria: the criteria considered important for optimal wind locations, such as wind speed or distance to shore. This leads to a ranking of locations and, in combination with the macro-scenarios, the development of site-specific scenarios for offshore wind deployment over time.

3.2 INTRODUCTION

As explained in this Deliverable's introduction, a detailed analysis of the different ways to develop a European future offshore grid requires the development of fictive (but realistic) topologies. As one main aim of an offshore grid will be the evacuation of offshore wind energy, offshore wind scenarios are a prerequisite of the development of topologies. Note that, because there is a high level of uncertainty about the evolution of offshore wind energy over the considered period (i.e. 2020-2050), the PROMOTioN consortium felt it was necessary not to base the development of topologies on a single scenario representing a "best estimate", but to use a set of three scenarios, representing an optimistic view on the development of offshore wind energy in the North Seas, a pessimistic view and an average view (i.e. a High wind scenario, a Low wind scenario and a Central wind scenario, respectively). As they will be used for the development of grid topologies, these scenarios should not only give aggregated values per country, but must also locate the offshore wind generation within the EEZ of each country. Indeed, the geographical distribution of OWFs (e.g. close to shore or far from shore) could impact the optimal way to develop the European offshore grid. It must be emphasised that there is also a high level of uncertainty about the locations of OWFs up to 2050. Consequently, the developed scenarios do not intend to predict these locations, but rather aims at giving a plausible geographical distribution.

To define these scenarios, a two-step approach was adopted within the PROMOTioN project. First, macro-scenarios for the North Seas were defined, giving figures for the various North Seas countries up to 2050. Second, these macro-scenarios were translated into OWFs with a specific location and commissioning date.

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This Chapter presents the main features of the methodology followed to develop these scenarios and the corresponding results. It is complemented by Appendix I, giving more details on the methodology. It is structured as follows. Section 3.3 explains how the PROMOTioN consortium derived three macro-scenarios. Then, Section 3.4 summarises the methodology followed to translate these macro-scenarios into specific projects.

3.3 DEFINITION OF THREE MACRO-SCENARIOS FOR THE NORTH SEAS

Estimating how the installed offshore wind energy capacity will evolve over the upcoming decades is a perilous exercise because numerous factors (e.g. technical, economic, political factors) could impact drastically the figures, and there is an important uncertainty attached to these factors. However, the purpose of the PROMOTioN's offshore wind generation scenarios is not to predict the future, but to support the development of fictive (but realistic) topologies building on levels of current deployment. Furthermore, several offshore wind generation scenarios have already been proposed. For these reasons, the definition of three macro-scenarios for the North Seas within PROMOTioN was strongly based on a review of past scenarios, to ensure alignment with existing forecasts. These were then split into country-level estimates based on national considerations (e.g. national policies, characteristics of the corresponding power system), before being further sub-divided into specific projects. Note that each scenario started from the same baseline – offshore wind deployed in 2020. The next subsections provide more detail on the development of these macro-scenarios for the North Seas.

3.3.1 ANALYSIS OF THE STATUS QUO

The starting point for the deployment plan corresponds with the end of the PROMOTioN project: 2020. The initial conditions should thus reflect the expected installed capacity of offshore wind energy in 2020. As it is a near future [at the time the scenarios were developed], the degree of confidence about these initial conditions is high: projects that should be commissioned in the upcoming years are known. However, it would not appear relevant to try to predict exactly the installed capacity in 2020 for two main reasons: this capacity will evolve during the year 2020 (i.e. the capacity on December 31 will be higher than the capacity on January 1) and there is uncertainty on the exact commissioning dates of new OWFs. Nevertheless, from the analysis of WindEurope data about existing OWFs and projects of future OWFs, it can be estimated that around 19.6 GW of offshore wind energy should be installed in the North Seas by 2020. This is lower than reported in [1], as these predictions were made prior to the actual commissioning date. Table 3-1 shows the split of per country and per sea basin. These figures will be used as initial conditions.

3.3.2 ANALYSIS OF EXISTING SCENARIOS

The period considered in PROMOTioN is from 2020 to 2050. Numerous offshore wind scenarios covering part or all of this period have already been proposed within R&D projects (e.g. WindSpeed, e-Highway 2050), by organisations (e.g. ENTSO-E, WindEurope, IRENA, IEA) or by companies. The purpose of this Section is to review some of them, in order to derive a likely range of installed offshore wind capacity in the North Seas over the considered period. Even scenarios limited to shorter time horizons (e.g. 2030 or 2040) are of interest because they can help to integrate robust short-term or mid-term trends in PROMOTioN scenarios. Similarly, not all scenarios disaggregate figures per sea basin, but even scenarios giving only a total number for Europe

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can be of interest because they can help to integrate robust European trends in PROMOTioN scenarios. The scenarios explicitly reviewed in this report are the following: the WindEurope scenarios for 2030 [11], the ENTSO-E TYNDP2018 scenarios for 2030 and for 2040 [2], and the scenarios proposed in the IRENA innovation outlook offshore wind energy [12]. The PROMOTioN consortium reviewed other scenarios but they are not detailed here for the sake of brevity.

Table 3-1 - Expected offshore wind energy per country and per sea basin in the North Seas in 2020.

COUNTRY	SEA	CAPACITY (GW)	
Belgium	North Sea	2.3	
Denmark	North Sea		1.2
	Skagerrak		
	Kattegat		
France	North Sea	0.0	0.0
	Channel	0.0	
Germany	North Sea	6.2	
Ireland	Irish Sea	0.0	
Netherlands	North Sea	1.7	
Norway	North Sea	0.0	
United Kingdom	North Sea	5.2	8.2
	Irish Sea	2.6	
	Channel	0.4	

In [11], WindEurope proposes three scenarios for the offshore wind power cumulative capacity in the European Union in 2030: a low scenario, a central scenario and a high scenario.

- In the central scenario, 323.3 GW of wind energy is installed in the EU-28 by 2030, among which 253.1 GW of onshore wind energy and 70.2 GW of offshore wind energy. That would be more than double the capacity installed at the end of 2016 (160 GW). With this capacity, wind energy would produce 888 TWh of electricity, equivalent to 30% of the EU-28's power demand.
- The High wind scenario assumes favourable market and policy conditions including the achievement of a 35 EU renewable energy target. In this scenario, 397.4 GW would be installed in the EU by 2020, among which 298.5 GW of onshore wind energy and 98.9 GW of offshore wind energy. This would be 23% more capacity than in the central scenario and about two and a half times more capacity than the capacity installed at the end of 2016.
- In the low scenario, however, there would be 256.4 GW of wind capacity in 2030, among which 206.9 GW of onshore wind energy and 49.5 GW of offshore wind energy.

Just taking the North Seas element of each of these scenarios means 38.1 GW of offshore wind capacity by 2030 for the low scenario, 53.2 GW for the central scenario and 70.2 GW for the high wind scenario.

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In [2], the two ENTSOs for gas and electricity (i.e. ENTSOG and ENTSO-E) present their joint set of scenarios describing possible European energy futures up to 2040, for the use in the TYNDP 2018. All scenarios detail electrical load and generation, along with gas demand and supply, within a framework of EU targets and commodity prices. Figure 3-1 shows the scenario building framework. The TYNDP scenarios include a “best estimate” pathway for the short and medium term but their storylines for the longer term reflect increasing uncertainties: the Distributed Generation (DG) scenario, the Sustainable Transition (ST) scenario, and the Global Climate Action (GCA) scenario. An external scenario, the EUCO30 scenario, is also included in the scenarios used for the TYNDP 2018 and replaced the GCA scenario for 2030 within the TYNDP framework. Consequently, the ST and the GCA scenarios share the same pathway up to 2030, as shown in Figure 3-1. This review focuses thus on the DG and the ST scenarios for 2030, and for the DG, the ST and the GCA scenarios for 2040. In the DG scenario, 296.9 GW of wind energy is installed in the EU-28 by 2030, among which 231.1 GW of onshore wind energy and 65.7 GW of offshore wind energy. The figures are very similar for the ST scenario in 2030: 297.1 GW of wind energy is installed in the EU-28, among which 231.2 GW of onshore wind energy and 65.9 GW of offshore wind energy. For the North Seas, it means 52.0 GW of installed offshore wind capacity for both the DG and the ST scenarios. For 2030, the DG and the ST scenarios are thus close to the central scenario of WindEurope, although with an installed capacity slightly lower. For 2040, in the DG scenario, 412.7 GW of wind energy is installed in the EU-28, among which 315.2 GW of onshore wind energy and 97.5 GW of offshore wind energy. In the ST scenario, 394.1 GW of wind energy is installed in the EU-28 by 2040, among which 296.2 GW of onshore wind energy and 97.9 GW of offshore wind energy. Finally, in the GCA scenario, 500.7 GW of wind energy is installed in the EU-28 by 2040, among which 346.1 GW of onshore wind energy and 154.6 GW of offshore wind energy. The split per sea basin is not given by the scenarios, but if we assume that around 80% of the offshore wind capacity of Germany is located in the North Sea and around 30% of the offshore wind capacity of France is located in the Channel, we obtain approximately 52.4 GW of offshore wind capacity in the North Seas in 2030 for the DG and ST scenarios, 73.1 GW in 2040 for the DG scenario, 74.6 GW in 2040 for the ST scenario and 100.4 GW in 2040 for the GCA scenario. The ENTSO-E TYNDP 2018 DG and ST scenarios are thus quite in line with the WindEurope central scenario in 2030.

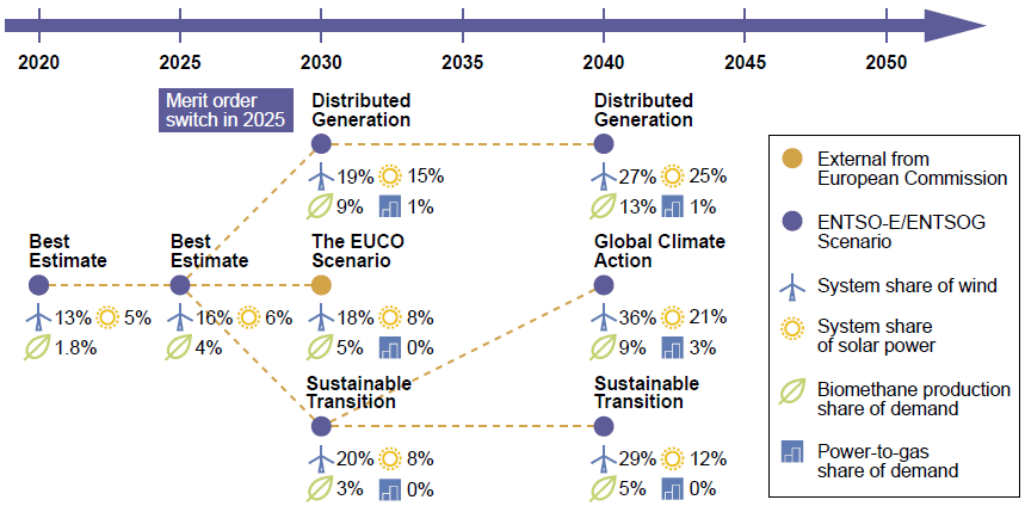

Figure 3-1 - The scenario building framework for TYNDP 2018 [2].

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In [12], three scenarios for the development of offshore wind energy during the period 2016-2045 are proposed: a low, a central and a high scenario. The central scenario assumes that offshore wind is an important player in a renewable energy mix by 2045 with an operating capacity of about 159 GW of offshore wind in Europe in 2045. High and low progress scenario are then based on changing the cost of energy of offshore wind compared to the central scenario. These sensitivities on the cost lead to an operating capacity of about 187 GW of offshore wind in Europe in 2045 for the high scenario, and to an operating capacity of about 136 GW for the low scenario. Note that the central scenario assumes also a capacity of about 63 GW in 2030 and of about 123 GW in 2040. The high scenario assumes a capacity of about 145 GW in 2040. Consequently, the WindEurope central scenario, the ENTSO-E TYNDP 2018 DG and ST scenarios and the IRENA central scenario are quite aligned for 2030: they lead to a range between 63 GW and 70 GW for the installed offshore wind energy in Europe. For the North Seas, it leads to a range between approximately 50 GW and 55 GW. Furthermore, the IRENA high scenario appears to be quite aligned with the ENTSO-E GCA scenario for 2040. Taking the same rule of thumb for the split between the North Seas and other locations in Europe than in the ENTSO-E GCA scenario for 2040 (i.e. 66% of European offshore wind energy is in the North Seas), we can consider that the IRENA high scenario leads to approximately 123 GW of offshore wind in the North Seas in 2045.

3.3.3 MACRO-SCENARIOS FOR THE NORTH SEAS

The offshore wind scenarios of the PROMOTioN project will be used to develop offshore grid topologies, in order to support a Deployment Plan for a future European offshore grid. It is obvious that a European offshore grid makes only sense if offshore wind energy is significantly developed. Therefore, it would be irrelevant to use a scenario with a very low development of offshore wind, as it will obviously not induce the need for an offshore grid, and would be then useless to support the Deployment Plan. Consequently, the PROMOTioN consortium chose to use scenarios generally ambitious in terms of offshore wind development in the North Seas, but nevertheless realistic. As the near future is almost locked, this ambition can be fully expressed in the far future.

As a result, the PROMOTioN High wind scenario should be aligned with optimistic evaluations of offshore wind capacity by 2030 (e.g. WindEurope high scenario), but could be more ambitious afterwards. To decide upon the level of ambition for this High wind scenario, two additional information elements are worth to be emphasised. First, the technical potential of the North Sea alone, as evaluated by BVG Associates for WindEurope [13], is around 4,000 TWh/year, which means approximately 900 GW using a capacity factor of about 50%. Second, according to Ecofys [14], a total offshore wind capacity of 230 GW would be required in the North Seas by 2045 to ensure a fully sustainable power supply for the surrounding countries in line with the Paris Agreement's objective. Similarly, according to [15], a total offshore capacity between 240 and 440 GW would be required in Europe by 2050 to make the European power system in line with the Paris Agreement's objective. The gap between these requirements and the scenarios analysed above must be emphasised. Under these circumstances, it appears desirable to be more slightly ambitious than the existing scenarios, and the technical potential shows that it is feasible. Consequently, the PROMOTioN consortium proposes to use a target of 205 GW of offshore wind energy installed in the North Seas in 2050 for the High wind scenario, with 160 GW in 2045, 125 GW in 2040 and 65 GW in 2030. The figure of 125 GW for 2040 is 20% higher than the ENTSO-E

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GCA scenario for 2040, and the figure of 65 GW for 2030 is well aligned with the WindEurope high scenario for 2030. Table 3-2 details this PROMOTioN High wind scenario.

The PROMOTioN Central wind scenario can then be chosen closer to existing scenarios. For 2030, it can be close to the WindEurope central scenario. For 2040, it can be close to a middle ground between the three ENTSO-E TYNDP 2018 scenarios (i.e. DG, ST, and GCA). For 2045, it can be close to the IRENA scenarios. Consequently, the PROMOTioN consortium proposes to use a target of 150 GW of offshore wind energy installed in the North Seas in 2050 for the Central wind scenario, with 115 GW in 2045, 90 GW in 2040 and 49 GW in 2030. Table 3-2 details this PROMOTioN Central wind scenario.

Finally, the PROMOTioN Low wind scenario can correspond to the pessimistic variants of the existing scenarios. For 2030, it is close to the WindEurope scenario. Afterwards, it can be seen as a little bit more conservative than the ENTSO-E TYNDP 2018 DG scenario for 2040 and a little bit more conservative than the IRENA low progress scenario in 2045, to reach 90 GW of wind energy in the North Seas by 2050. Table 3-2 details this PROMOTioN Low wind scenario[15].

Table 3-2 - PROMOTioN offshore wind scenarios for the North Seas.

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

3.3.4 COUNTRY ALLOCATION

In Section 3.4, the numbers of Table 3-2 are translated into specific projects based on an assessment of the best available locations in the North Seas. This assessment relies strongly on wind resources, shown in Figure 3-2, conditioning the energy that can be harvested, but also on the bathymetry, shown in Figure 3-3, conditioning the technical feasibility and the installation costs. However, before translating the numbers of Table 3-2 at the level of the North Seas into specific projects, it is necessary to define also a “country allocation”, i.e. the offshore wind capacity within the EEZ of each North Seas country. Indeed, due to the dominance of national approaches for the development of offshore wind energy, it is likely that each country will develop offshore wind energy in line with the capability of its power system to absorb that energy. It would thus be too naïve to assume that the best locations at a European level are chosen to bring offshore wind energy up to the values of Table 3-2, whatever the corresponding country is.

This need to define a country allocation is confirmed by the split per country/zone of the WindEurope and ENTSO-E scenarios, as shown in Table 3-3. Note that, in order to keep consistency with bidding zones of the European internal electricity market, numbers are given for Great Britain on one side and for the Irish Island (Northern Ireland and Republic of Ireland) on the other side. This is why the terminology “country/zone” is used.

[15] Note that at the time of the establishment of the scenarios these were considered ´extreme´. However, more recent research has indicated that the PROMOTioN High wind scenario is in line with relatively moderate predictions (for example the WindEurope vision of 450 GW – with 212 GW in the North Sea alone [64])

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Although Denmark has a significant potential with good conditions as shown by Figure 3-2 and by Figure 3-3 (e.g. bathymetry, wind speed), these scenarios lead to very small installed capacity in Danish EEZ, compared to the three main countries/zones: Germany, Great Britain and the Netherlands. Given the small size of the Belgian EEZ, the number of 8.3 GW in the ENTSO-E GCA 2040 appears high. To the best of the authors' knowledge, that number is not motivated by a detailed study of the potential. According to an internal estimation of Tractebel, the potential of the Belgian EEZ, given the constraints described in Section 3.4, is rather around 6 GW. On the contrary, it must be emphasised that the value of 28.3 GW for Great Britain in the ENTSO-E GCA 2040 appears quite low, because the WindEurope high scenario gives already a value of 30 GW for 2030.

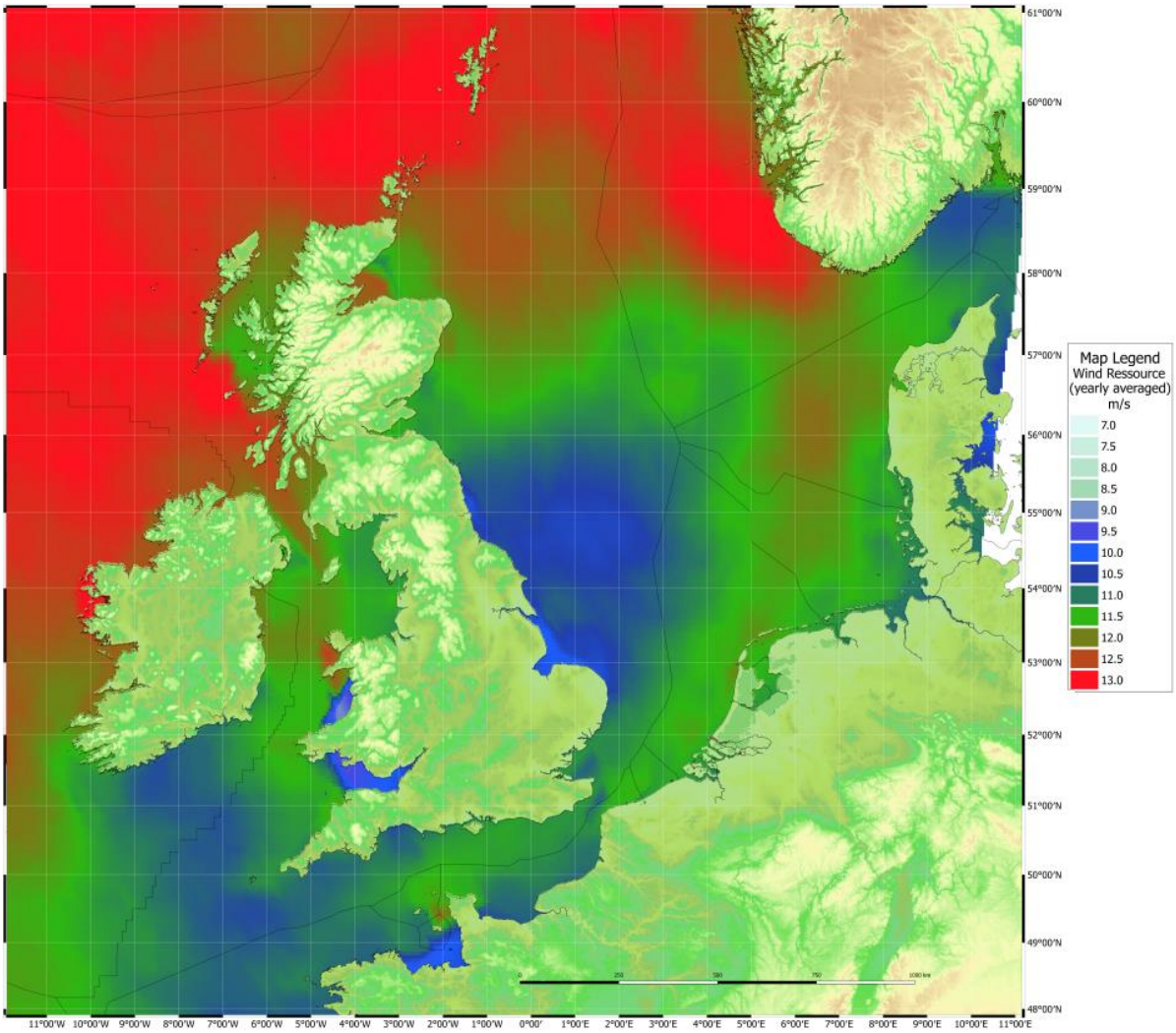

Figure 3-2 - Map of average wind speed for the North Seas.

An additional consideration of interest to understand the relative capabilities of North Seas countries to absorb offshore wind is the size of related power systems, which could be expressed by their peak loads. Table 3-4 shows the estimation of the peak loads for the year 2020, according to the TYNDP 2018 "Best estimate" scenario for 2020. The relatively low evolution of offshore wind energy in Denmark compared to Germany and to Great Britain can thus be motivated by the fact that the peak load in Denmark (7.1 GW) is much lower than the peak load in Germany (88.7 GW) and in Great Britain (61.9 GW). Note that the peak load in the Netherlands

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(18.1 GW) is closer to the Danish one, but the Netherlands, as part of Continental Europe, are strongly interconnected with their neighbours and there is an important political willingness to develop offshore wind energy.

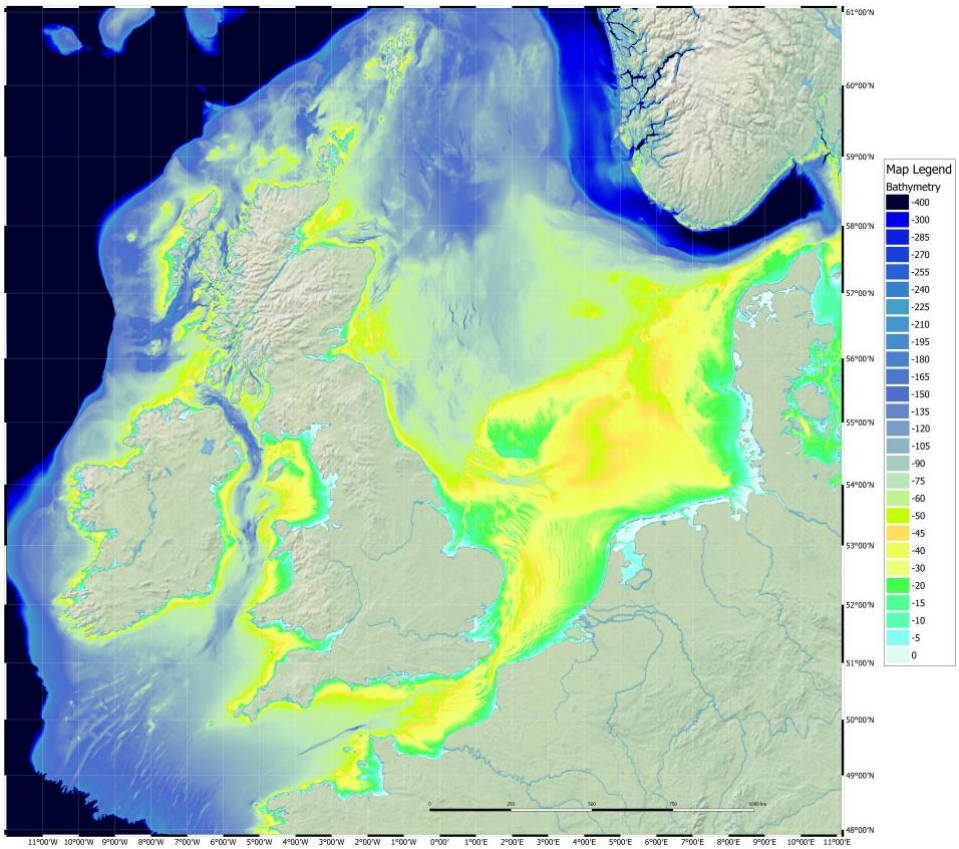

Figure 3-3 - Map of bathymetry for the North Seas.

Table 3-3 - Country allocation of offshore wind energy in the North Seas for WindEurope and ENTSO-E scenarios.

COUNTRY/ZONE	WINDEUROPE LOW 2030	WINDEUROPE CENTRAL 2030	WINDEUROPE HIGH 2030	ENTSO-E DG 2040	ENTSO-E ST 2040	ENTSO-E GCA 2040
Belgium	1.6	4.0	4.0	3.3	3.8	8.3
Denmark	2.4	3.3	5.1	2.3	3.1	5.3
Germany	11.2	12.0	16.0	20.6	21.1	26.8
Great Britain	18.0	22.5	30.0	27.3	27.3	28.3
France	1.3	2.1	3.3	3.5	3.2	6.0
Ireland (NI+RI)	1.2	1.8	2.0	1.4	1.4	2.2
Netherlands	4.5	11.5	18.5	14.7	14.7	23.4
Norway	0.0	0.0	0.0	0.0	0.0	0.0
Sweden	0.0	0.0	0.0	0.0	0.0	0.0

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Table 3-4 - Peak load for the North Seas countries.

COUNTRY/ZONE	PEAK LOAD IN 2020, ENTSO-E TYNDP BEST ESTIMATE SCENARIO (GW)
Belgium	14.2
Denmark	7.1
Germany	88.7
Great Britain	61.9
France	93.3
Ireland (NI+RI)	7.3
Netherlands	18.1
Norway	23.5
Sweden	27.9

Following these considerations, the country allocation for the PROMOTioN High wind scenario for 2040 is based on the ENTSO-E TYNDP 2018 GCA scenario for 2040, with the following main modifications: the offshore wind capacity in the Belgian EEZ is limited to 6 GW, a small floating offshore wind capacity is considered in the Norwegian EEZ (0.4 GW), and the considered capacity for Denmark, Germany, Great Britain and the Netherlands is increased. Then, for 2050, the offshore wind capacity is further increased for these four countries/zones. Table 3-5 shows the detailed country allocation for this High wind scenario between 2020 and 2050. Note that the starting point (i.e. 2020) corresponds to numbers given in Table 3-1. It must be emphasised that the installed capacity by 2050 in the Dutch EEZ and in the Danish EEZ is much higher than the peak load of the corresponding country in 2020 (i.e. more than 2.5 times the peak load). Grid reinforcements, including additional interconnectors, and flexibility resources will thus be needed for the corresponding onshore grids to absorb and evacuate these amounts of wind energy.

Table 3-5 - Country allocation of offshore wind energy in the North Seas for the PROMOTioN High wind scenario.

COUNTRY/ZONE	2020	2030	2040	2050
Belgium	2.3	3.7	6.0	6.0
Denmark	1.2	3.0	8.6	17.8
Germany	6.2	16.7	32.6	47.9
Great Britain	8.2	23.5	39.4	60.8
France	0.0	0.9	6.0	10.7
Ireland (NI+RI)	0.0	2.1	2.8	5.8
Netherlands	1.7	16.5	31.9	52.2
Norway	0.0	0.0	0.4	4.0
Sweden	0.0	0.0	0.0	0.0

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As the PROMOTioN Central wind scenario is close to a middle ground between the three ENTSO-E TYNDP 2018 scenarios for 2040, the starting point of the country allocation is the average between these three scenarios. Offshore wind capacity in the Belgian EEZ and in the French EEZ are then revised to slightly lower values, while the capacity in the German EEZ and in the British EEZ are revised to slightly higher values. Then, for 2050, the offshore wind capacity is further increased for all the countries (at the exception of Norway and Sweden, staying at 0 in the North Seas). Table 3-6 shows the detailed country allocation for this Central wind scenario between 2020 and 2050.

Table 3-6 - Country allocation of offshore wind energy in the North Seas for the PROMOTioN Central wind scenario.

COUNTRY/ZONE	2020	2030	2040	2050
Belgium	2.3	3.4	4.5	5.2
Denmark	1.2	2.2	3.6	10.1
Germany	6.2	13.6	29.2	44.8
Great Britain	8.2	19	32.2	53.7
France	0.0	0.4	2.4	5.4
Ireland (NI+RI)	0.0	1.5	1.7	2.8
Netherlands	1.7	8.9	16.5	28
Norway	0.0	0.0	0.0	0.0
Sweden	0.0	0.0	0.0	0.0

For the Low wind scenario, because it is a little bit more conservative than the ENTSO-E TYNDP 2018 DG in 2040, a similar country split can be adopted, with values slightly lower, especially for Germany, Great Britain, France and the Netherlands. Table 3-7 shows the detailed country allocation for this Low wind scenario between 2020 and 2050.

Table 3-7 - Country allocation of offshore wind energy in the North Seas for the PROMOTioN Low wind scenario

COUNTRY/ZONE	2020	2030	2040	2050
Belgium	2.3	2.3	2.7	3.2
Denmark	1.2	1.8	2.3	3.6
Germany	6.2	12.7	17.1	26.0
Great Britain	8.2	15.2	22.1	34.3
France	0.0	0.0	1.6	2.5
Ireland (NI+RI)	0.0	1.0	1.1	1.7
Netherlands	1.7	3.0	11.1	18.7
Norway	0.0	0.0	0.0	0.0
Sweden	0.0	0.0	0.0	0.0

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3.4 TRANSLATION OF MACRO-SCENARIOS INTO SPECIFIC PROJECTS

3.4.1 GENERAL APPROACH

Although it gives a first idea of a possible geographical repartition of future OWFs, the country split of Section 3.3.4 cannot be used directly to generate corresponding offshore grid topologies: the capacity and the geographical coordinates of specific projects are also needed. For that purpose, the process of site selection should be emulated for each country. Various factors impact that process, including political factors, and it is thus not possible to predict exactly what will be the future OWFs in each country. However, only a plausible geographical distribution of OWFs is needed for the development of topologies supporting the deployment plan. Such a distribution can be derived through a methodology considering the main technical, economic and environmental criteria used in site selection processes for actual OWFs. These criteria can be divided in two categories: exclusion criteria and selection criteria. Indeed, it might be unfeasible to develop OWFs in specific zones in the North Seas, for various reasons such that these zones are used for other purposes (e.g. shipping lanes). These reasons will define the exclusion criteria. Then, between the various zones available for the development of OWFs, the best locations from the point of view of the offshore wind developers are expected to be selected first (e.g. high wind speed, low water depth, close to shore).

The methodology used to translate the macro-scenarios defined in Section 3.3 into specific projects will thus consider successively exclusion criteria, in section 3.4.2, and selection criteria, in Section 3.4.3. Finally, section 3.4.5 presents the results of the analysis.

3.4.2 EXCLUSION CRITERIA

The first stage to select sites to develop future OWFs in the EEZ of each country is to exclude areas that are considered as unsuited for such a development. Several criteria are used to estimate if a specific area must be excluded, as listed hereafter.

WIND VELOCITY

Wind velocity is directly linked to the Levelised Cost of Energy (LCOE) of the project and is a primary variable in choosing the site. A criterion on wind velocity can be used at this stage to exclude all areas with a fragile wind-energy potential. The available offshore wind potential can be quantitatively expressed through the mean wind velocity 80 meters above the mean water level. Marine areas with a mean wind velocity lower than 7 m/s are considered unsuitable for offshore energy projects according to the industrial best practice.

WATER DEPTH

The water depth is also important for two reasons: it impacts the cost (due to the mooring, anchorage and cabling), and it impacts the relevant technology to use, i.e. fixed-bottom foundation or floating. For fixed-bottom foundation, current technologies provide the possibility to develop marine wind farms at a maximum depth of 70 meters with a stable offshore structure. Consequently, areas with a water depth of more than 70 meters are excluded for fixed foundation systems. For floating offshore, areas with a water depth of less than 50 meters or more than 400 meters are excluded.

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Distance from shore

Offshore wind turbines can have an undesired aesthetic impact when they are located close to the shore. For that reason, areas within 12 nautical-miles from the shore are excluded.

Shipping lanes and other navigable waterways

Shipping lanes (also called sea lanes and sea roads) are specific paths used for large freight and passenger vessel passage on oceans and seas. The locations of shipping lanes and other navigable waterways are considered as exclusion areas for the development of OWFs due to the potential obstruction it can cause for vessels. Furthermore, a minimum distance exclusion of 0.27 nautical-miles (500 meters) on both sides of shipping lanes and other navigable waterways is added as a buffer zone to prevent conflicts.

Dredging areas

Sand and gravel dredging activity takes place in the North Seas to preserve, to improve and to deepen existing navigational channels and to create new channels. Furthermore, sand and gravel are extracted from the seabed at specific locations for the construction industry, for coastal defence or for beach replenishment. These locations must be considered as exclusion areas, as well as a buffer zone of 0.27 nautical-miles (500 meters) around each area.

Confirmed shipwrecks

During the Second World War, battleships generated a huge amount of shipwrecks. The known large shipwrecks must be considered as exclusion areas. Note that most of the large shipwrecks are identified, but some remain undiscovered.

Oil and gas fields

The North Seas hold a significant number of oil and gas fields in their waters. Related oil and gas platforms and pipelines need to be excluded from the list of potential sites for OWFs, together with a buffer zone of 0.27 nautical-miles (500 meters) for platforms and for pipelines.

Dumping areas

Two types of residue can be dumped at sea: sediments and other geological materials resulting from dredge works (dredge spoil dumping) and munitions (e.g. bombs, grenades, torpedoes, mines). Dumping areas must be considered as exclusion areas, as well as a buffer zone of 0.27 nautical-miles (500 meters) around each area.

Marine protected areas

Human activities in the North Seas can endanger many of the species populating the North Seas. It led the environmental agencies of all the EU countries to classify specific locations as marine protected areas within the Natura 2000 network of protected areas, as shown in Figure 3-4. However, it must be emphasised that all marine protected areas cannot be simply considered as exclusion areas because offshore wind energy can be developed in protected Natura 2000 sites [16]. Consequently, exclusion areas are limited to migration bird

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corridors and sanctuaries, because wind turbines entail a significant risk of injury to birds in these areas. Buffer zones of 1 nautical mile (1852 meters) are considered around these migration bird corridors and sanctuaries.

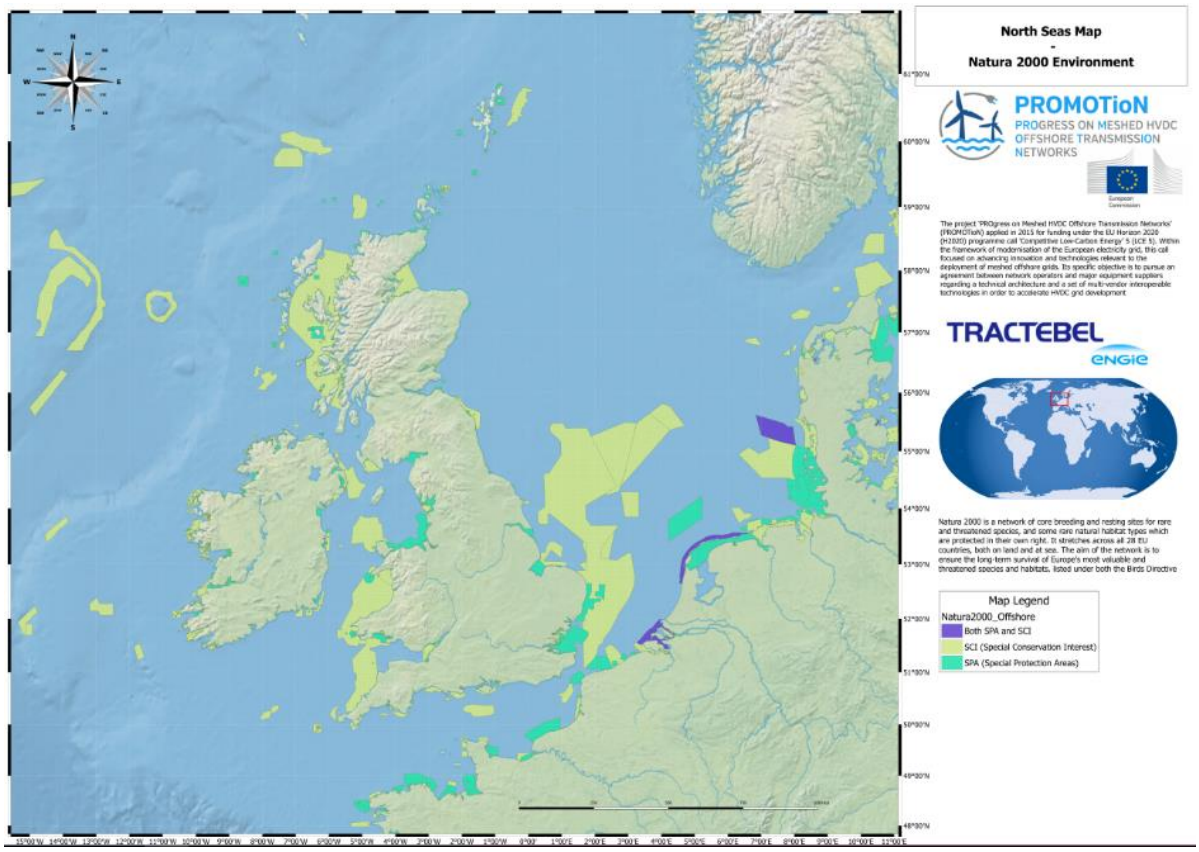

Figure 3-4 - Natura 2000 network of protected areas in the North Seas.

TELECOM AND ELECTRICAL SUBSEA CABLES

Telecom and electrical cables connecting the different North Seas countries together and with other countries are considered as exclusion areas, as well as a buffer zone of 0.27 nautical-miles around each area.

EXISTING OFFSHORE WIND FARMS

Because it is not possible to redevelop an OWF where another one is already present, existing OWFs are considered as exclusion areas. Figure 3-5 shows the considered existing OWFs. Figure 3-6 shows the all these exclusion factors, with the exception of the distance from shore.

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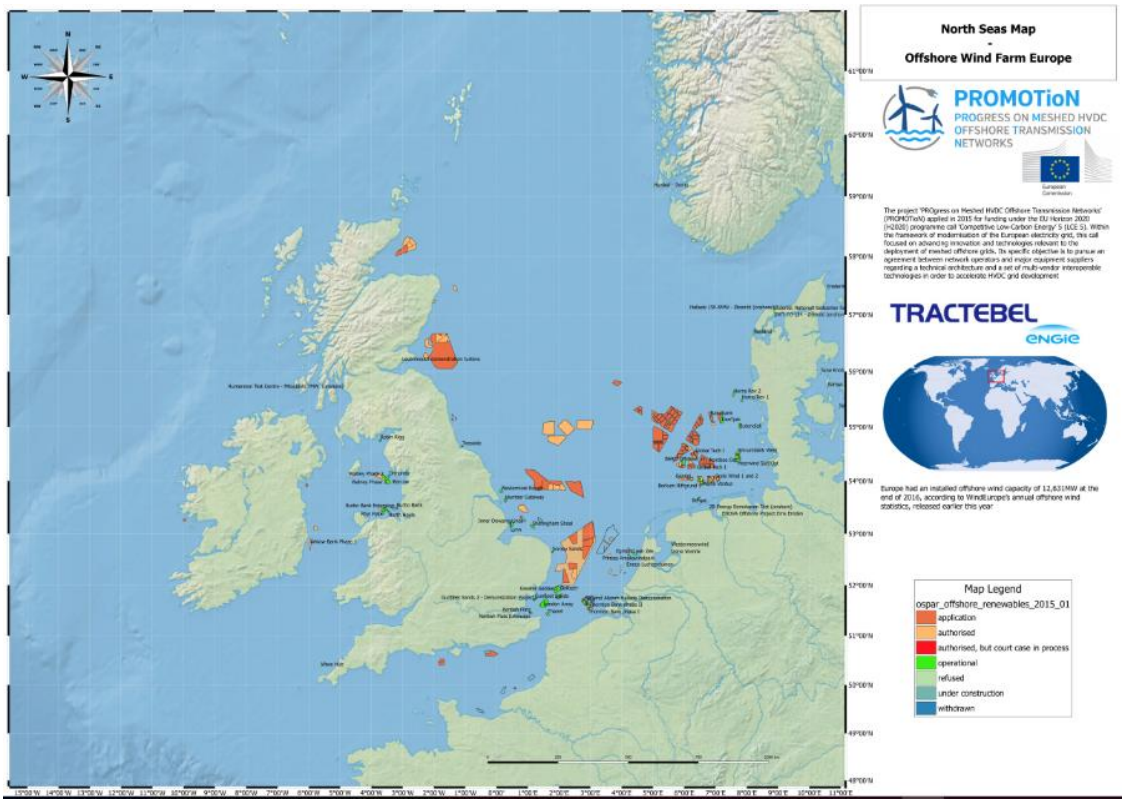

Figure 3-5 - Map of existing offshore wind farms (and decided projects) in the North Seas.

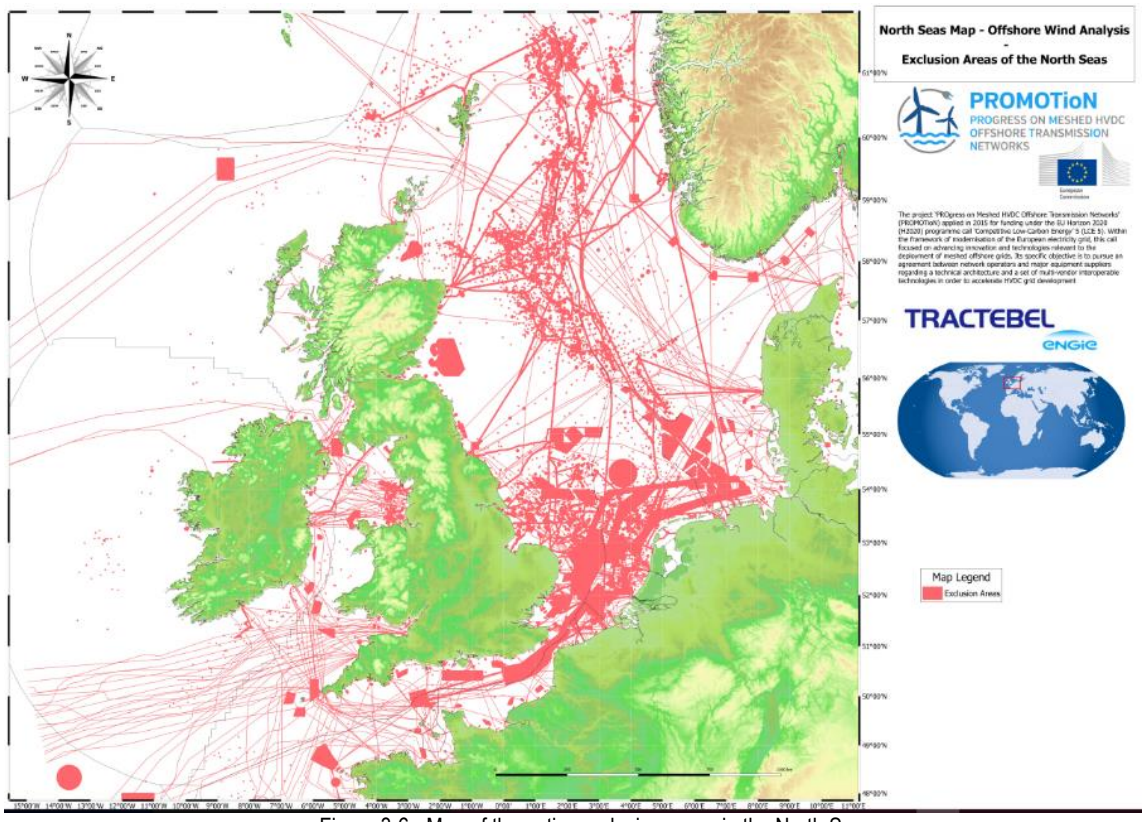

Figure 3-6 - Map of the entire exclusion areas in the North Seas.

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3.4.3 SELECTION CRITERIA

Following the exclusion of some areas for the development of OWFs according criteria listed in Section 3.4.2, the remaining areas must be evaluated and ranked in order to select the best projects in each EEZ to meet the targets defined in Section 3.3.4. For that purpose, several selection criteria are used, related to the wind resource, the bathymetry, the available grid connection and the available shore-side support (i.e. port infrastructure). These factors are the main parameters impacting the LCOE. The selection criteria will then be combined in a single siting factor score through an overlay weighted analysis. The purpose of this siting factor is to reflect in an approximate way the LCOE of offshore wind energy at the various locations. For each offshore wind scenario, the projects with the best siting factor will be selected to reach the national objectives. This Section briefly explains each criterion and the way they are combined. Details are given in Appendix I.

The wind resource is the first important factor conditioning the LCOE, because it determines how much energy can be produced at a location. For an accurate estimation of the LCOE, the complete statistical distribution of wind speed should be used. Nevertheless, as a proxy, the average annual wind speed at 80 meters above the sea level, shown in Figure 3-2, can be used. This average wind speed is classified into eleven categories for the overlay weighted analysis, with a ranking score going from 0 for a wind speed of 7 m/s to 10 for a wind speed of more than 13 m/s.

The bathymetry is a second important factor impacting the LCOE. Indeed, the water depth has a direct impact on the technology, the design, the construction and thus the cost of turbine foundation. For instance, monopile and gravity foundations can be used for shallow waters (up to 40 meters), jacket foundations, including tripods, can be used for deeper waters up to 200 meters, but with an optimal range of 30-60 meters, and floating wind turbines would be suitable for water depths higher than 50 meters. Different overlay weighted analyses will be performed for the for the fixed-bottom foundations and for floating wind turbines, because the exclusion criteria are different (see supra). Nevertheless, the principle is the same for both: it is more costly to develop offshore wind energy in deep waters compared to shallow waters. For the fixed-bottom foundations, the bathymetric is classified into ten categories, with a ranking score going from 0 for a water depth higher than 70 meters to 10 for a water depth of less than 30 meters. For floating wind turbines, the bathymetric is also classified into eleven categories, with a ranking score going from 0 for a water depth higher than 400 meters to 10 for a water depth of less than 100 meters.

When developing offshore wind energy, the availability of a close grid connection is an important criterion to consider. Indeed, if offshore wind energy must be transferred over long distances, it can increase significantly the total cost, due to the required investment cost and the losses. Proximity to the existing transmission systems is beneficial to offset these costs as much as possible. For the overlay weighted analysis, the distance to the closest grid connection point is classified into eleven categories, with a ranking score going from 0 for a distance of more than 250 km to 10 for a distance of less than 50 km.

The last important factor impacting the LCOE considered in the selection criteria is the proximity to transportation infrastructure and logistical infrastructure is. Indeed, the transport of offshore turbine parts from the shore to the OWF location require an important harbour due to their extremely large dimensions and the distance to convenient harbours impact the development cost. Note that it can also impact the maintenance

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cost. For these reasons, for the overlay weighted analysis, the distance to the closest harbour point is classified into eleven categories, with a ranking score going from 0 for a distance of more than 250 km to 10 for a distance of less than 50 km.

Finally, these factors are combined into a single siting factor through a weighted sum. The relative weighting factors are: 15% for the wind speed, 50% for the water depth, 30% for the distance from the grid and 5% for the distance from harbour. Figure 3-7 shows the resulting siting factor for the fixed-bottom foundations. Areas in green are the most interesting ones, with a weight of 10, and areas in red are the least interesting ones. These results show larges areas of interest in between the coast of the United Kingdom (UK) and France, Belgium, Netherlands. Other strong interesting sites are along the cost of Germany and largely in Denmark. Figure 3-8 shows the resulting siting factor for the floating wind turbines. The colour code is the same. The weighting analysis for the floating foundation type shows thus less areas of interest in overall. Most of them are along the east coast of England and Scotland, a reasonable size site are located in the Irish Sea and at the south of England in the Manche. Other sites are located in Norway far away from the coast.

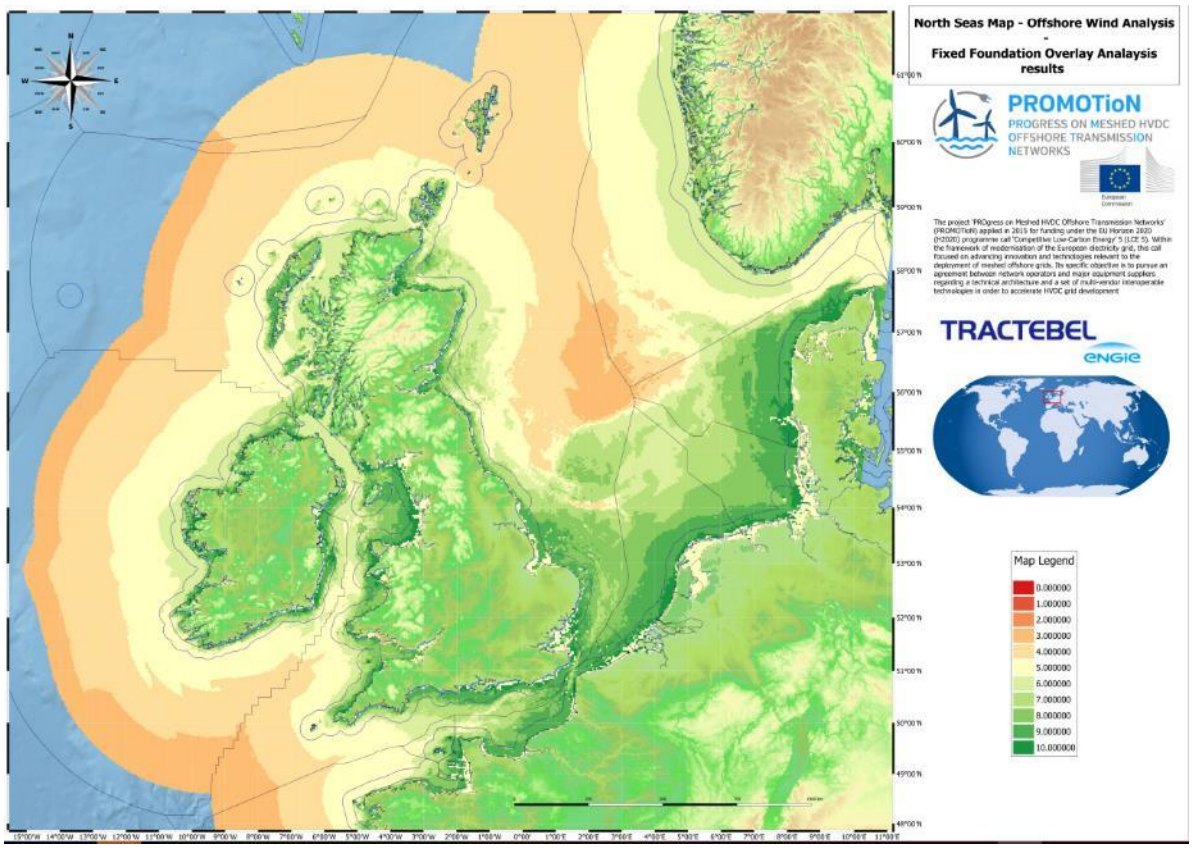

Figure 3-7 - Map of the weighted analysis results for floating wind turbines in the North Seas.

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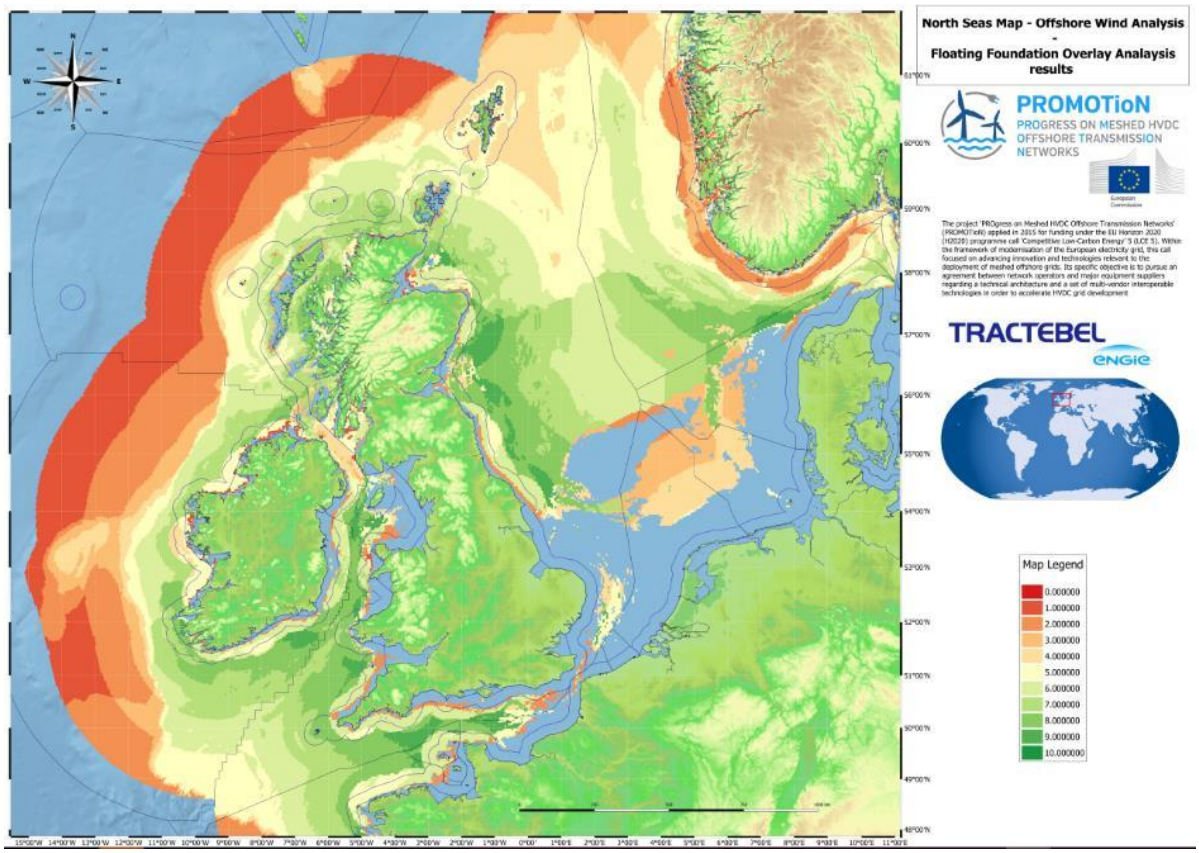

Figure 3-8 - Map of the weighted analysis results for floating foundations in the North Seas.

3.4.4 CANDIDATE PROJECTS

The combination of the exclusion criteria and of the selection criteria leads to the candidate projects shown in Figure 3-9. Floating foundations candidate projects are shown in blue and fixed foundations candidate projects are shown in yellow.

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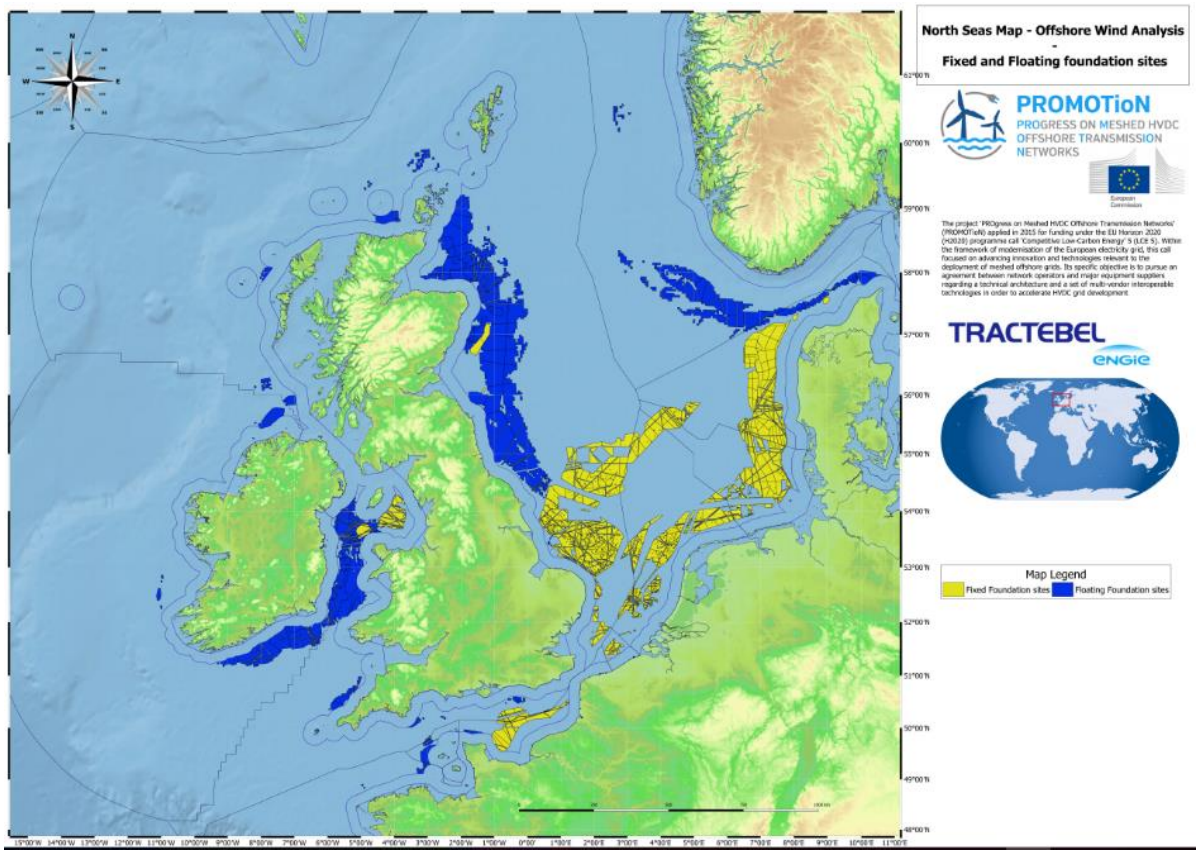

Figure 3-9 - Map of the candidate projects for both fixed and floating sites in the North Seas.

3.4.5 FINAL SELECTION OF PROJECTS PER SCENARIO

The final selection of projects to reach the each offshore wind capacity defined per country by each scenario is based on the candidate projects and on the direct result of the weighting. The weighting gives a priority score from 1 to 3 to each candidate project, allowing an assortment of most interesting projects first. Figure 3-10 shows the selected projects (for both fixed and floating foundations) for the High wind scenario, Figure 3-11 shows the selected projects for the Central wind scenario and Figure 3-12 shows the selected projects for the Low wind scenario.

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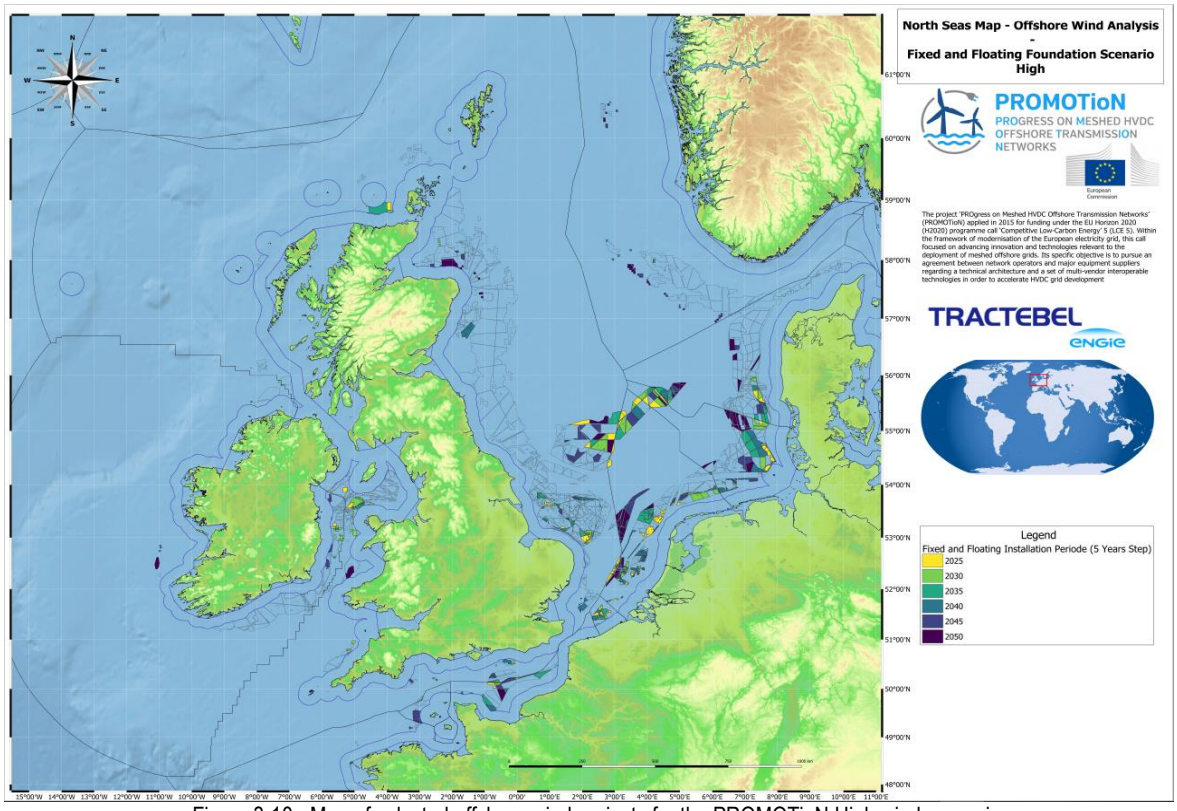

Figure 3-10 - Map of selected offshore wind projects for the PROMOTioN High wind scenario.

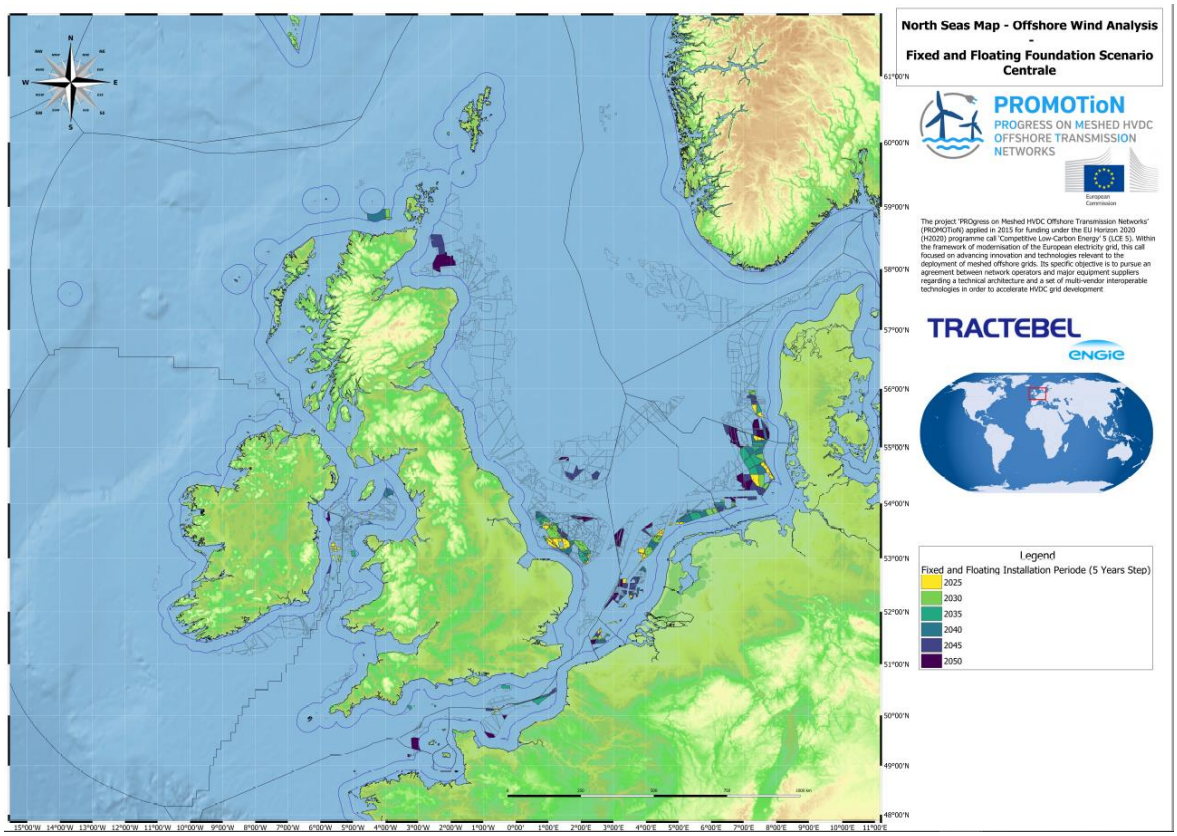

Figure 3-11 - Map of selected offshore wind projects for the PROMOTioN Central wind scenario.

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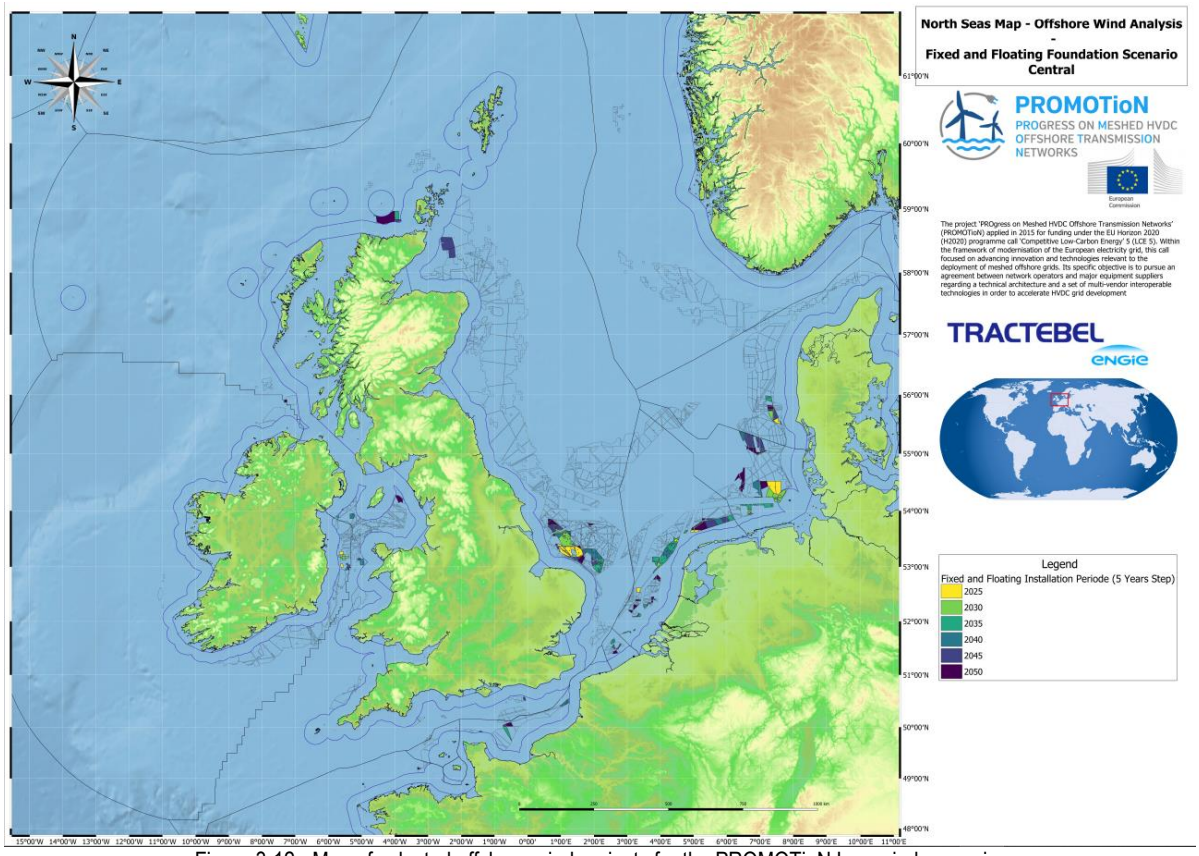

Figure 3-12 - Map of selected offshore wind projects for the PROMOTioN Low wind scenario.

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4 GRID DEVELOPMENT CONCEPTS

4.1 SUMMARY OF THE CHAPTER

The concepts exist to illustrate relatively extreme options. These are abstract descriptions of certain ways of designing a grid. Each concept will have its own design principles which are translated to rules for the network planning optimisation model. These concepts range in their complexity and their level of cooperation required. It is also shown that the concepts have different development routes through time, but that no real risk of lock-in to a specific concept is expected, except for the anticipatory investments made in platforms or artificial islands for the meshed concepts.

4.2 INTRODUCTION

Among other aspects, PROMOTioN sets out to investigate the benefits of MOGs compared to a conventional radial offshore grid. In order to do so, various arch-grid types were created, known as concepts. The concepts exist to illustrate relatively extreme options. These are abstract descriptions of certain ways of designing a grid. Each concept will have its own design principles which are translated to rules for the network planning optimisation model. Running the optimisation model then leads to the topologies, which are described in the next Chapter. The topologies might resemble each other much more than expected when taking into account the basic principles of the concepts. This is because the concepts are illustrated to show extreme or exaggerated forms of the grid types and the topologies are more steered towards efficient evacuation. In the topologies, the realisation of meshing is dependent on the economical evaluation performed by the optimisation model. Meshing between two hubs is therefore only justified when the benefits of this additional interconnection capacity exceeds its capital costs, which results in less meshing and less extreme structures. Also, in practise any MOG that is being built will likely be a combination of multiple concepts. This exercise therefore does not aim to create four actual options, but to illustrate what possibilities of extreme routes exist and the possible advantages of MOG.

4.3 DEVELOPING FOUR CONCEPTS

As an approach it was decided to find concepts that were as far apart as possible, whilst still being in the realm of possibility. This Chapter entails the specific design criteria and design philosophies behind each concept, it explains what each concept will look like and why it is created the way it is. This also leads into the optimisation rules for the topologies. These concepts described below were not the only conceivable concepts. More concepts were proposed and could and have been argued for. However, the PROMOTioN consortium agrees these four concepts cover the bandwidth of possible solutions of evacuating wind energy while also providing additional benefits that could be used for MOGs. As such, any other concept proposed is thought to be either similar to the concepts described below or incorporates different elements thereof.

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4.3.1 BUSINESS-AS-USUAL

In the Business-as-Usual (BAU) concept, the OWFs are connected radially to the grid. This may be in separate point-to-point connections, but some OWFs might also be bundled to reach a critical size of 2 GW. This standardised 2 GW concept utilises the most current HVDC equipment and is therefore not so much business-as-usual as previously but rather the continuation of a near-future high-end concept. However, connecting OWFs in a radial fashion is considered business-as-usual and thus this name has been attributed to this concept. Power exchange between countries is facilitated by separate point-to-point interconnection. Refer to Figure 4-1[16].

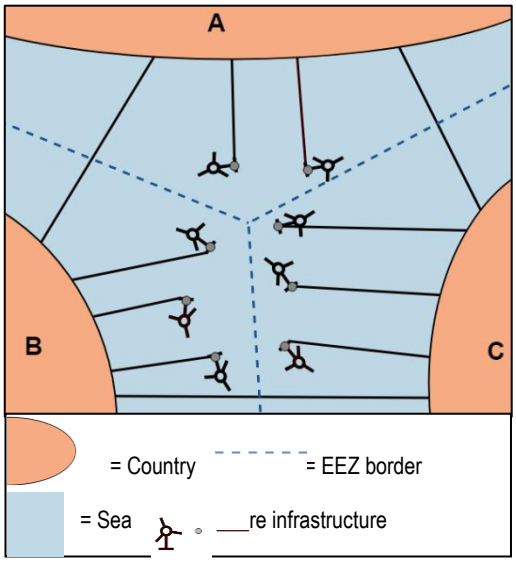

Figure 4-1 - Business-as-Usual design philosophy.

4.3.2 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 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. Refer to Figure 4-2[16].

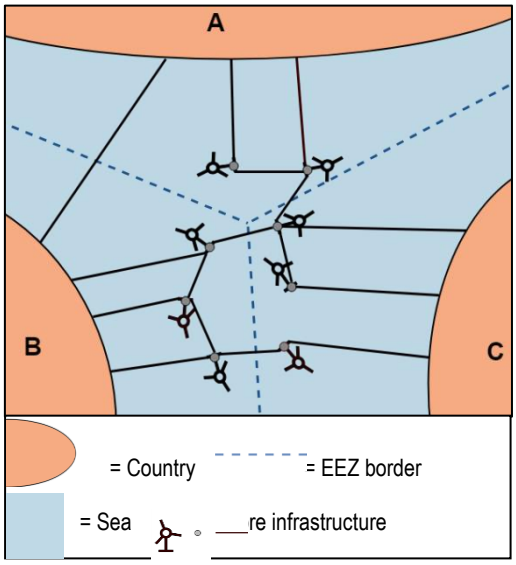

Figure 4-2 - National Distributed design philosophy.

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 economically be more 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[17]. Like in BAU, separate point-to-point

[16] N.B.: The figure does not represent actual proposed locations bur rather how such OWFs would be connected in this concept
[17] 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

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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 structure. This way the option of transporting power over the alternative paths can still be open when an individual link is unavailable. At present this structure is relatively new and the only interconnector similar to such kind[18] is Kriegers Flak Combined Grid Solution between East Denmark and Germany via German and Danish[19] offshore wind power plants.

4.3.3 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 structure 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 4-3[16].

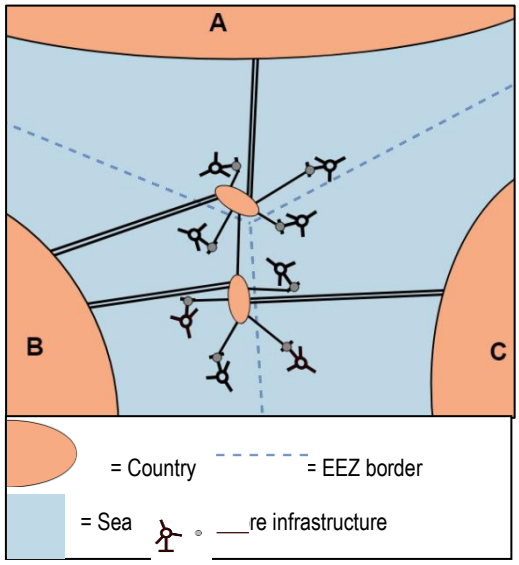

Figure 4-3 - European Centralised design philosophy.

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

[18] 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.
[19] The Danish OWFs and the interconnector are in commissioning at the time of writing.

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AC option still remains. Multiple hubs could be constructed in the North Seas which might, but need not, be connected to one another.

4.3.4 EUROPEAN DISTRIBUTED HUBS

The European Distributed Hubs concept (EUR) is designed based on a strongly connected decentralised strategy. Relatively small sized platform-based hubs are spread out over the North Seas and connected to each other via HVDC connection, as is illustrated in Figure 4-4[16]. National borders are not taken as a restriction, which results in relatively low cost hybrid interconnectors, as in the NAT concept. EUR allows for more flexible and technically optimal connections without restrictions on what should be connected to what location. To do this, it requires advanced DC grid technologies such as DCCBs and DC protection systems. The result is a highly resilient grid, where built-in ring structures provide alternative pathways in case of a cable failure. However, the load flow in the resulting meshed DC-network cannot be fully controlled by the existing converters anymore. This 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.

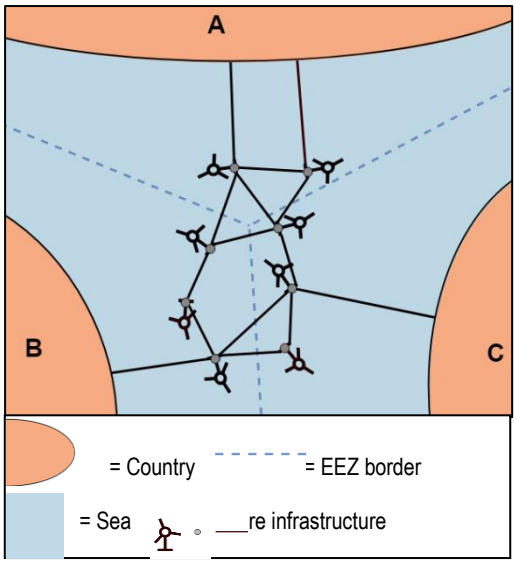

Figure 4-4 - European Distributed design philosopy.

4.4 DEVELOPMENT OF CONCEPTS THROUGH TIME

This Chapter entails a short explanation the development of each concept over time, how it may potentially develop into other concepts and which risks are involved due to lock-in.

4.4.1 DEVELOPMENT OF BUSINESS-AS-USUAL THROUGH TIME AND RISK OF LOCK-IN

BAU represents the current most prevailing situation and design practices of radial connections. OWFs are developed and directly connected to the country in which EEZ it is located. There is no cooperation or coordination between the countries in the development of their offshore grid. When price differences arise between countries (either chronic or temporal) a business case could be made for an interconnector, either regulated or following a merchant model. There is no clear technological development driving factor or change in the concept, except for that more and more capacity is added, which is then again connected radially to shore. At times more point-to-point interconnection is also added, as can be seen in Figure 4-5.

Like in the current situation, the BAU concept is flexible to be able to be adapted to other stages. Any final topology will still have multiple radial connections and they are very appropriate for individual standardised

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OWFs (e.g. up to 2 GW which can be evacuated with a single converter[20]). However, it must be considered that several suboptimal choices can be made that are BAU specific, e.g. dedicated interconnectors. In new combined options this is unlikely to be optimal and although a higher interconnection capacity is socially beneficial, a more optimal scenario will likely include them as part of the MOG. Additionally, radial links could be changed to be integrated in an MOG, but anticipatory investments[21] are then needed which is difficult to approve without planning and agreement with the regulator. For example, it might be economically efficient to oversize the cable to one OWF, to prepare connection for a later planned park, or reserve some space on a platform for a DCCB[22]. In the BAU concept this is not done by default, which might be sub-optimal. Any change towards another concept therefore might require significant investments, which could have been prevented with anticipatory investments. Additionally, there might be a technical lock-in due to varying voltage levels, which can only by resolved by additional (back-to-back)-converters and therefore higher costs. To prevent this, it is wise to steer towards (several) standardised voltage levels, or voltage levels used per area to allow for fusing of projects.

[20] Taking into consideration the capacity of currently available HVDC technologies
[21] For example, a two GW connection to an existing one GW windfarm, to anticipate for another one GW windfarm close by to be connected in a later period of time. These anticipatory investments are made because building a two GW line is cheaper than building two lines of one GW for each windfarm. There is some financial risk in doing this, as there could be a risk of the second park not being built.
[22] Currently, these anticipatory investments are only allowed in a time-period of five years. It is assumed this is not done in the BAU concept, but the same period is assumed in the other concepts.

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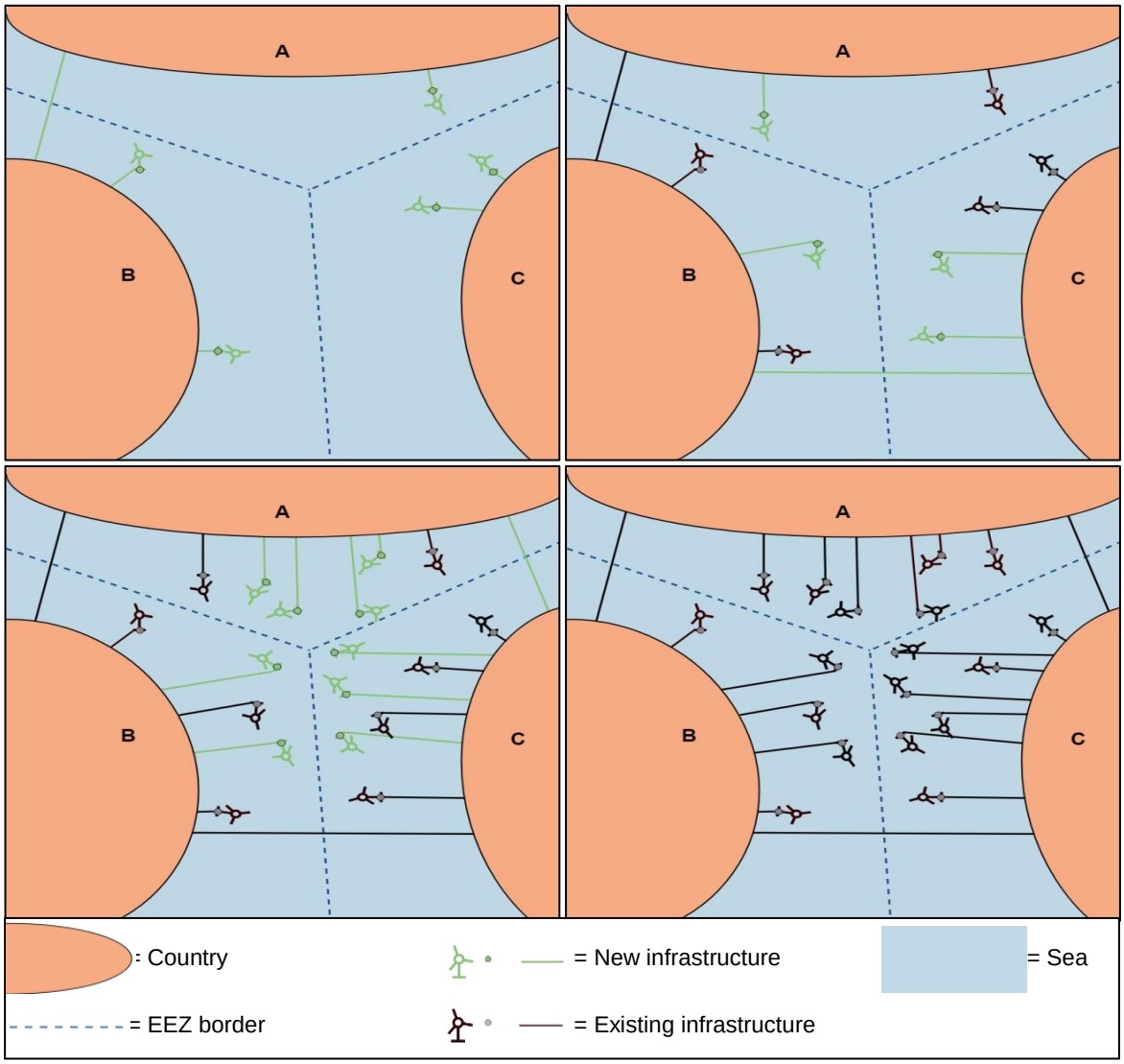

Figure 4-5 - Illustration of the development of the Business as Usual concept. N.B.: the development is hypothetical and does not illustrate considered time-steps in PROMOTioN.

4.4.2 DEVELOPMENT OF NATIONAL DISTRIBUTED HUBS THROUGH TIME AND RISK OF LOCK-IN

In the NAT concept each country develops its own national grid. In this development anticipatory investments might be made through e.g. slightly oversizing a cable in advance to already prepare for transport of additional power in the future. Refer to Figure 4-6. This optimises the cable capacity used, leading to more efficient investments. Interconnectors, hybrid or regular, can be proposed but are always considered an "add-on", as each national grid is capable of evacuating its nationally generated energy. There are still some regulatory challenges in combining the use of interconnection and onshore evacuation in the classification of these hybrid assets, but it does not require European regulation as the networks are constructed per country.

There are two types of risk to these features. The first is possible overinvestment in case there is a fall-back to a radial connection: an oversized cable and platform is then built but not used. The second is the loss of efficiency due to the lack of coordinated planning. If a certain OWF has a hybrid connection to another country and mostly

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uses that connection instead of the connection to its native country, the native cable is essentially overdesigned. The political relevance of building for your own market can then impede optimal investment efficiency.

Additionally, it might be tempting for nations to develop their grids in isolation, and therefore without internationally standardising voltage levels and/or equipment. This might lead to technical inoperability and will increase the price of (hybrid) interconnector projects, as additional equipment might then be needed in order for the grids to be coupled. This means some international agreement is still highly advisable, to allow for such coupling of grids. This would also allow for an easier change of focus towards more meshing.

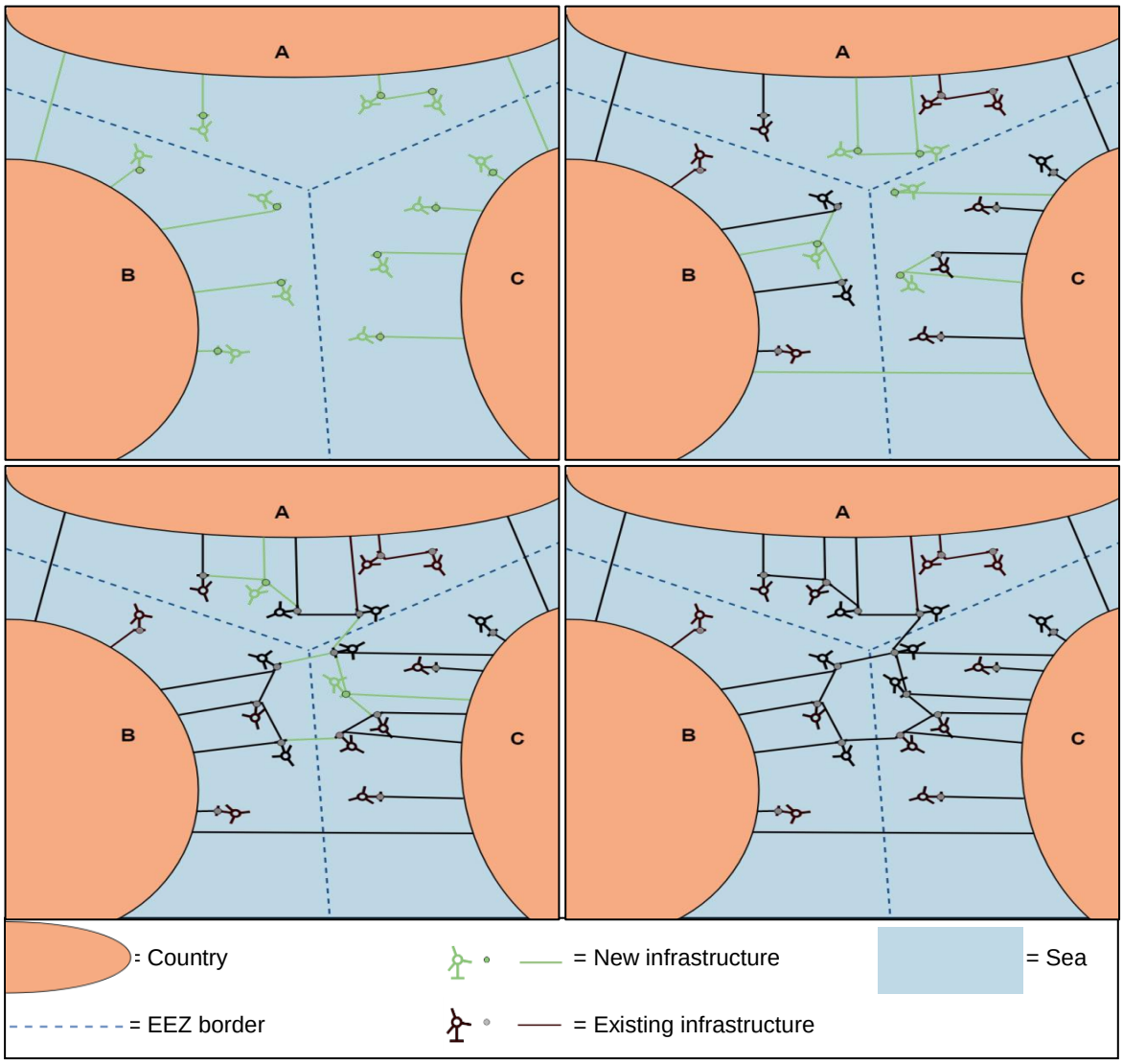

Figure 4-6 - Illustration of the development of the National Distributed concept. N.B.: the development is hypothetical and does not illustrate considered time-steps in PROMOTioN.

4.4.3 DEVELOPMENT OF EUROPEAN CENTRALISED THROUGH TIME HUBS AND RISK OF LOCK-IN

The HUB concept will only clearly develop itself after a few years, as the lead-time on hubs (e.g. islands) is 10-15 years. This is illustrated in Figure 4-7, where islands will need to be planned years ahead. However, that

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does not mean that offshore wind capacity should not be built during the permitting process. In the meantime, radial connections can be established in more remote areas with lower OWF densities. After some time, the first hubs will have been built and connections can then be made with these hubs, both from shore and from OWFs. Because of the sheer size of the projects, it is likely that the hubs will not be built in parallel but instead will be single cooperative projects of multiple nations.

The HUB concept could also undergo a technical development over time. The hubs could initially be connected with separate point-to-point links, connected to the DC side on the hub[23]. The AC side of the hub can then be weakly linked, creating alternative pathways on the hub. A possible development is to create a DC bypass, which could be further extended to include a large amount of GW, with DCCBs if necessary. This results in an HUB concept which shares characteristics with EUR, especially if the hubs are connected between each other with DC links. Additionally, a framework must be made for anticipatory investments, and the harmonisation and interoperability of components throughout the grid must be considered.

The HUB concept has the risk of a strong economic lock-in for this specific technology. That might however not be unfortunate as the hub, once constructed, would be a very suitable place to evacuate power to. Additionally, hubs will unlikely be the sole solution, as some more distant OWFs will likely be connected radially or in the more distributed fashion. The risk of HUB is delays in construction of the hubs, especially due to permitting processes. The time from planning to commission of the hubs might take up to 15 years, which is significantly longer than the planning horizon of most countries. Large hubs might therefore always end up being "the next solution". There are also several legal and environmental challenges related to placing hubs in an EEZ, especially if several countries wish to cooperate on these. This is true especially if the location of the hubs happens to be close to environmentally sensitive areas. As these areas might align with shallow waters, and therefore economically interesting maritime zones, this could be an area of conflict. Additionally, there is some financial risk in building a hub which needs to be planned and financed far ahead, as opposed to building platforms piece by piece. The fear that is associated with this risk, in combination with the long-term planning, makes it tempting to forever postpone a hub decision. Coordinated planning could potentially mitigate this risk.

Additionally, the national offshore grid is not necessarily sized to evacuate its own offshore wind energy. As national subsidy schemes rely on the evacuation of wind energy to the country in which the OWF is located, these will need to be revised.

[23] The hub will have an AC side, where OWFs are connected to, and a DC side, where the outgoing DC point-to-point cables are connected to.

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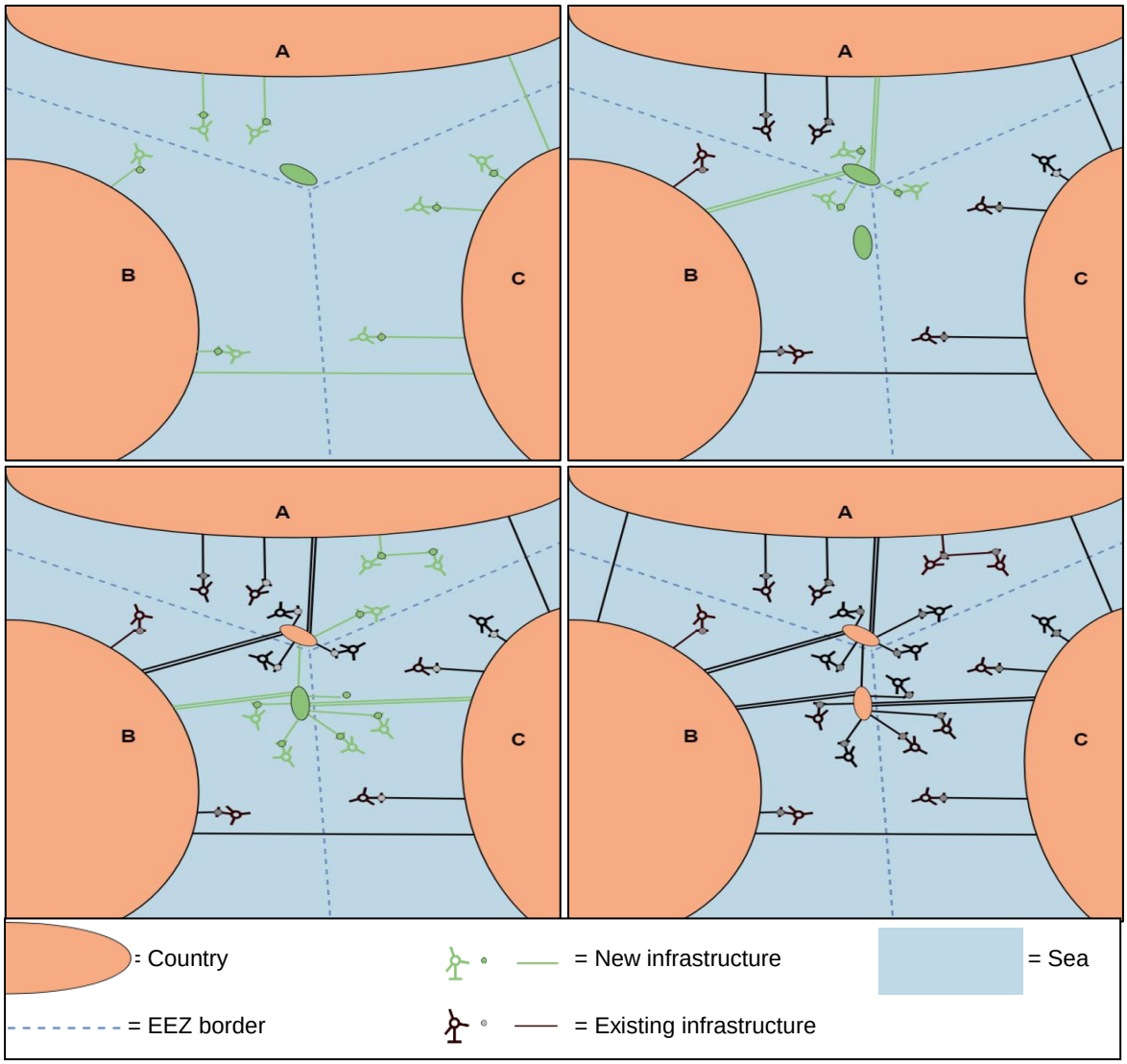

Figure 4-7 - Illustration of the development of the European Centralised concept. N.B.: the development is hypothetical and does not illustrate considered time-steps in PROMOTioN.

4.4.4 DEVELOPMENT OF EUROPEAN DISTRIBUTED HUBS THROUGH TIME AND RISK OF LOCK-IN

In this concept it is no longer necessary for each country to develop its national grid such that it may evacuate all wind generated in its EEZ, as wind generated in one country's EEZ may be directly exported to another country's shore. It is therefore free of the constraints that BAU and NAT have and can develop optimally. Figure 4-8 illustrates the development of the EUR concept. Through cooperation between countries, both wind generation evacuation as well as interconnection may be facilitated in early stages of development. The high degree of meshing of the grid allows for more flexibility of the evacuation of offshore wind power; e.g. the wind power generated in country A might easily be exported to country B, without country A having to be able to evacuate that wind power to its own power system. EUR is highly modular, meaning that the development can be very smooth. Some anticipatory investment might be needed to ensure aggregation of OWFs and cable landing space on platforms.

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EUR requires further development of DC grid technology (partly covered in PROMOTioN), but also a much greater level of cooperation between nations. Additionally, a framework must be made for anticipatory investments, and the harmonisation and interoperability of components throughout the grid must be considered. A large structure like EUR might prove a serious challenge towards both protection and controllability. One of the strengths of DC power is the greater ability to control power flow, compared to AC power. However, the challenge of controllability scales with increased grid complexity. Similarly, protection systems will have to be designed such that it is able to handle DC faults and to subsequently decouple faulted parts of the grids in case of a failure. Again, as the national offshore grid is no longer sized to evacuate its own offshore wind energy, national subsidy schemes for OWFs will need to be revised. PROMOTioN's WPs set out to address exactly these challenges. Although possibly very rewarding, it therefore also makes EUR the most complex concept.

The EUR concept is also defined by its lack of boundaries. It does not need to mind borders or technology and could therefore be developed economically optimal. However, this also entails a high level of cooperation. The grid would be able to develop towards other concepts and there should not be any risks associated with this. Similarly to NAT, some anticipatory investments might be made which may not be used. However, given the scale of the developments predicted, averaging over 30 GW per each five year period, it is unlikely that a risk of a single link not being finished would occur or have a major impact on the overall grid costs upon occurrence.

Especially prevalent in the EUR concept is the risk of over-planning interconnection capacity. The capacity of interconnection in the MOG is influenced by onshore market prices, where a difference in market prices between countries can make a business case for an interconnector[24]. However, the market prices within countries are highly speculative and uncertain and are impacted by multiple developments in the onshore market. There is, therefore, a higher risk associated with stranded assets in the development of the EUR concept when interconnection capacity is based on the prognosis of market prices.

[24] An interconnector can be used to sell low-priced energy to a high-priced market, thereby generating a profit. There is a positive business case in the construction when the profits are higher than the investment in the interconnector. Also, interconnection capacity leads to a higher social welfare benefit, thereby alternatively meriting the investment of the interconnector.

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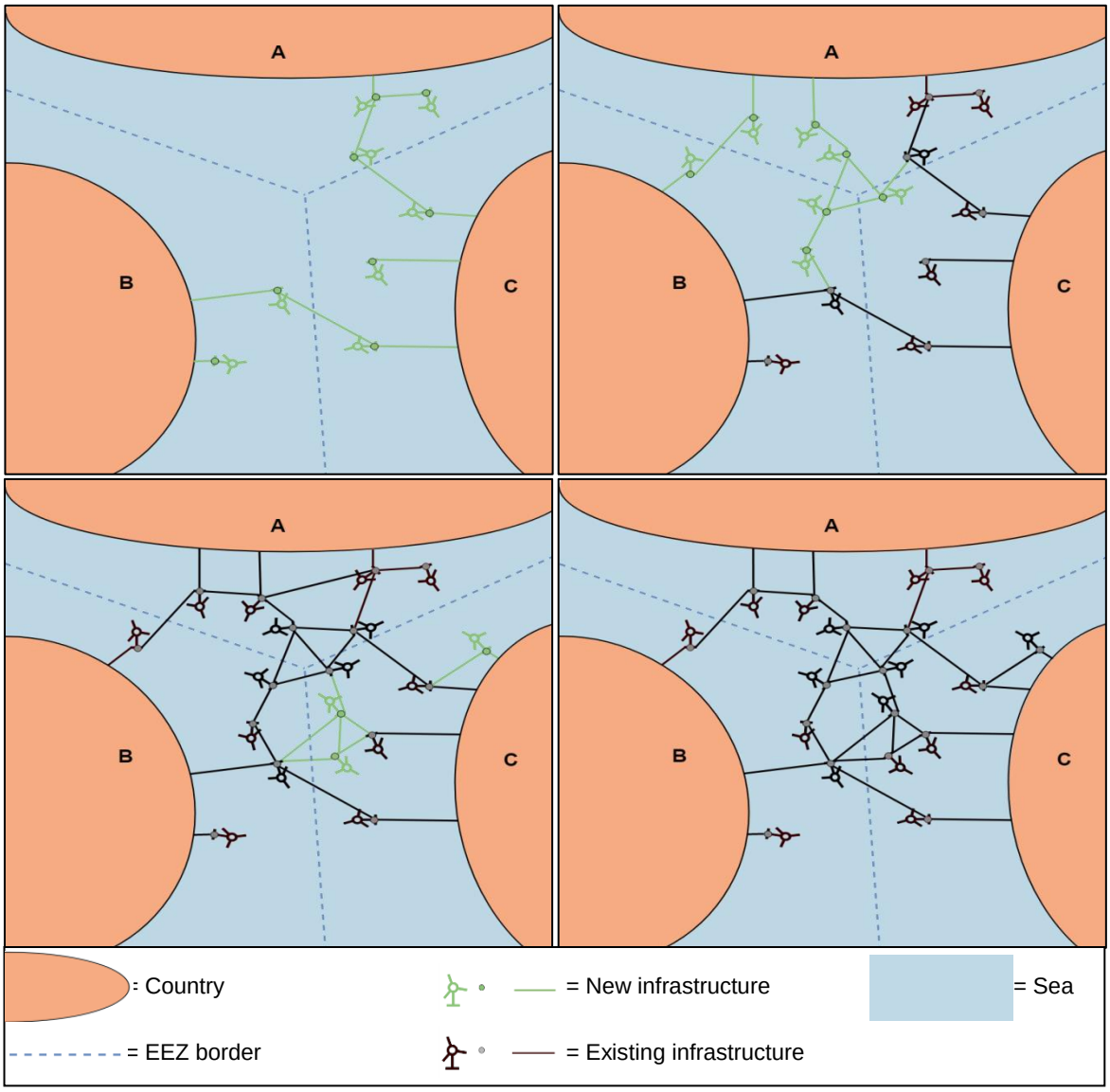

Figure 4-8 - Illustration of the development of the European Distributed concept. N.B.: the development is hypothetical and does not illustrate considered time-steps in PROMOTioN.

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5 GRID TOPOLOGIES

5.1 SUMMARY OF THE CHAPTER

This Section describes the method used for the development of the topologies. The method can be divided into three main steps:

1. Primary optimisation: The offshore grid topology is first optimised to evacuate energy at least cost, ignoring the connected markets and the possibilities for trading between them.
2. Secondary optimisation:
   a. The results of the primary optimisation are converted into a set of zones and transfer capacities.
   b. The €/ MW cost of transfer capacity between zones is estimated.
   c. The offshore grid is then optimised starting from the transfer capacities from the primary solution, with the optimisation being free to add additional transmission capacity.
3. The solution found is disaggregated into a detailed grid model and its technical feasibility is tested.

For each of the concepts, the results are displayed and discussed. Additionally, the cable length required for all the concepts is given, on which a sensitivity analysis is done. Seven key messages are drawn in this Chapter:

1. The proposed radial connection appears to be a competitive option and is the first building block
2. The combined use of the offshore grid for wind evacuation and interconnectors is an important driver for meshing/multi-terminal
3. In all concept and scenarios, the topology will evolve gradually from a few multi-terminal connections to a more complex structure. Eventually, a backbone will interconnect several multi-terminal connections. It has also been shown that all wind scenarios require a high level of interconnection.
4. Reduction in cable length from one concept to another is sensitive on input assumptions. Depending on the assumptions, the difference is very significant or not. If the difference is small, the costs of other aspects (such as protection devices, platforms, advanced controls) have to be considered.
5. The Dogger Bank seems an ideal candidate to form a backbone (or “hub”) because of the short distances between offshore wind plants. No clear benefits to connect all the multi-terminal structures together to form a single grid (meaning extra-costs and complexity).
6. The results are very sensitive to the input assumptions which was further explored in the sensitivity analysis.
7. For the High wind scenario, an increase of the interconnection capacities is needed but is not enough to evacuate all the produced wind energy. Therefore, large-scale storage (onshore and/or offshore) will be needed in all concepts.

5.2 INTRODUCTION

This Chapter aims at picturing what an HVDC offshore grid could look like up to the horizon 2050. It must be noted that there are numerous uncertainties about the potential evolution of the offshore grid. For this reason, a set of potential options are covered by defining four different concepts (as described in Chapter 4). For each concept, a certain philosophy is followed. The philosophy is linked to a certain risk/investment strategy. For

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example, the BAU approach is a lower risk and lower initial investment approach. On the other hand, the HUB concept requires high initial investments which try to drive the development of the North Sea grid. The NAT concept invests in multi-terminal and meshed HVDC connections with the constraint to be able to evacuate the installed wind energy of each country to its national shore. The most challenging approach is the EUR concept which considers that the MOG is a single network and that wind can be evacuated to any onshore connection. This approach will require significant changes in the regulatory and financial framework.

For all approaches, it has been considered that an anticipatory investment is needed and that there is a maritime spatial planning coordination aiming at aggregating windfarm projects. This allows to reach a critical size (currently around 900 MW in Germany but larger than 1 GW in the future), making the construction of an HVDC platform economic. In other words, even in the BAU concept, coordination between projects is required to optimise the number and size of offshore HVDC platforms.

In this Chapter, each of the topologies is assessed based on an investment cost and interconnection benefit point of view. Financing, regulatory or legal frameworks are not in the scope of this Chapter. The Chapter is structured as follows. First, the methodology to develop the MOG topologies is described in Section 5.3. In Section 5.4 the results are presented for the High wind scenario[25]. A sensitivity analysis is made in Section 5.5**.** Finally, Section 5.6 concludes. More details about the implementations and the assumptions used can be found in Appendix II.

5.3 METHOD

This Section describes the method used for the development of the topologies. The method can be divided into three main steps:

4. Primary optimisation: The offshore grid topology is first optimised to evacuate energy at least cost, ignoring the connected markets and the possibilities for trading between them.
5. Secondary optimisation:
    d. The results of the primary optimisation are converted into a set of zones and transfer capacities.
    e. The €/ MW cost of transfer capacity between zones is estimated. This includes connections made in the primary solution AND connections not envisaged by the primary solution but that have the potential, based on inspection, to offer further economic benefits thanks to trade between the countries they connect.
    f. The offshore grid is then optimised starting from the transfer capacities from the primary solution, with the optimisation being free to add additional transmission capacity.
6. The solution found is disaggregated into a detailed grid model and its technical feasibility is tested. A more refined estimate of the costs is derived. Should this differ significantly from the assumptions derived in 2(b), it may be necessary to return to step 2(c) using the updated costs.

The approach outlined above assumes perfect foresight of the scenario up to 2050. It would also be possible, though more time-consuming, to investigate whether certain grid designs would be more amenable to changes in the scenario part-way through e.g. a change in wind capacity deployment. This could be studied in a

[25] Results for the Central and Low scenario are found in Appendix III.

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simplistic way, using e.g. 2030 as a single point in time at which the information that is put in to the optimisation is altered. As the concepts are not found to have much risk of lock-in, as described in Section 4.4, this step is not further considered.

It must be noted that care is taken to assure consistency for each step of the different concepts to allow a fair comparison. The development of the topologies results in technically feasibly transmission projects. The overall methodology is presented Figure 5-1, with each separate step further explained in the subsections below.

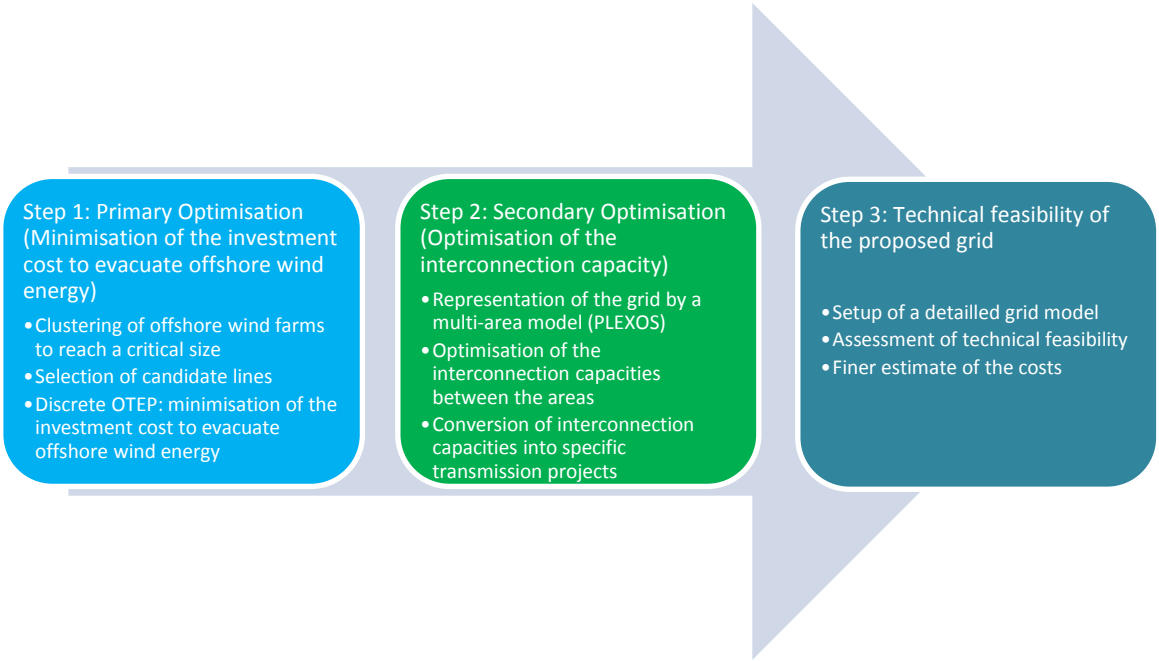

Figure 5-1 - Flowchart of the methodology for developing a meshed offshore grid.

5.3.1 STEP 1 - PRIMARY OPTIMISATION: MINIMISATION OF THE INVESTMENT COST TO EVACUATE OFFSHORE WIND ENERGY

The objective of the primary optimisation used for the development of the topologies is that the design of the offshore grid must comply with the following points:

- Minimisation of the actualised investment cost
  - CAPEX of cables and substations
- Such that, for peak offshore wind generation in the healthy state (N-0), energy and building constraints are met:
  - Balance equation at each offshore node
  - Balance equation at each onshore node
  - Flow constraints on cables
  - Integer constraint on the number of cables, with different types of cables
- Such that, for peak offshore wind generation reduced by the allowed loss of power infeed in single contingency state (N-1), energy constraints are met:
  - Balance equation at each offshore node
  - Balance equation at each onshore node

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- Flow constraints on cables

In other words, the offshore grid must be able to evacuate the peak offshore wind energy reduced by the allowed loss of power infeed after a single contingency (WP1). It is important to note that the assumption on the allowed loss of power infeed might significantly affect the topology of an offshore grid.

The input of this step 1 is the results of the development of the wind scenarios (described in Chapter 3). These wind scenarios results are processed to cluster wind farms close to each other until a critical size is reached. This clustering process is described in Section 5.3.1.1 and allows to determine the number of offshore HVDC converter stations required in the offshore grid. Once these HVDC offshore platforms have been determined, the objective is to assess how to connect them between each other and to shore. This is done by selecting a certain number of candidate lines. The set of candidate lines is different from one concept to another and is determined according to the concept philosophy, which is explained in Section 5.3.1.2.1. Then, an Optimum Transmission Expansion Planning (OTEP) approach is used to evaluate what would be the topology which requires the lowest investment cost. The mathematical formulation of the OTEP can be found in Section 5.3.1.2.2.

5.3.1.1 CLUSTERING OF OFFSHORE WIND FARMS

It has been shown in previous studies that there was a clear benefit to aggregate windfarms close to each other and minimise the number of DC platforms. This is for example currently the case for connecting German offshore windfarms. Therefore, a first step of clustering is performed for all concepts. The main objective of this clustering step is to determine in each area allocated for offshore wind how many HVDC offshore platforms are required to evacuate the offshore production to the shore via the MOG.

The input data required for the clustering of OWFs derive from the results of the offshore wind generation scenarios (described in Chapter 3). From these wind scenarios, areas in the North Seas likely to be selected for the installation of wind farms are identified. In each of these areas, a power density has been assumed based on the total surface of the area and assumption on wind turbine size. The areas have been selected and ranked according to the weighing formula explained in Section 3.4. It must be noted that the proximity of these areas to each other is also a very significant factor to take into consideration when planning an offshore grid. It is therefore assumed that the maritime spatial planning of offshore areas will influence the development of the topology. Subsequently, the clustering approach tries to take into account the time evolution of the wind farms installed capacity.

The GIS analysis performed to obtain the best potential locations for future offshore windfarms provide areas in the North Seas. These areas are of several sizes and are delimited by certain conditions such as exclusion zone in the maritime territory or size to reach the national target as explained in the previous Section. Therefore, these areas have to be converted to potential wind farm projects. This is done using a “hierarchical clustering with complete linkage”. This clustering technique allows to specify a maximum distance between any two points of a cluster, which guarantees that the distance between a windfarm and a potential HVDC converter platform is smaller or equal to the half of this distance. A second parameter used in this clustering is the maximum installed capacity that is allowed in a cluster. This makes sure that the clusters’ installed capacities are not larger than

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the maximum amount that can be connected to an offshore platform. If the size of the cluster is larger than the specified value, a second cluster is then created. An illustration of this clustering step can be seen in Figure 5-2.

It must be noted that for some concepts the size constraint had to be relaxed to be able to further reduce the number of offshore points and hence the complexity of the problem. When the size constraint is relaxed, it means that an offshore cluster might represent more than one HVDC offshore platform.

Using this approach is a very intuitive way to group wind farms that could economically be connected in AC to an HVDC offshore platform. The value has been set to 2 GW for the BAU approach while for the national and European approach, it is assumed that more complex combinations of AC and DC platforms can be used to reach a higher size for each cluster.

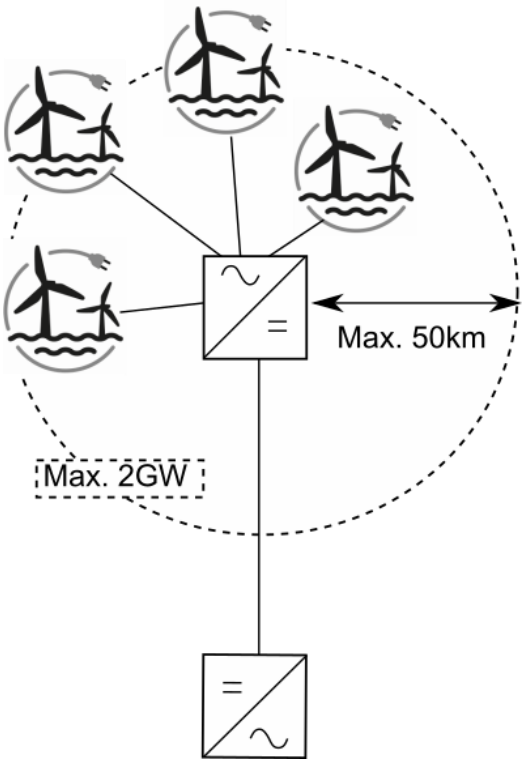

Figure 5-2 - Individual windfarms are aggregated into a “node” of maximum 2 GW.

The clustering approach has two main objectives:

1. Group wind farms close to each other that can potentially be connected to the same HVDC offshore platform
2. Reduce the complexity of the problem by reducing the number of offshore nodes

There are several potential designs of the AC connections inside each cluster (using only 66kV cables or AC offshore platforms). These designs are considered in the estimation of costs studied in Chapter 5.

5.3.1.2 TRANSMISSION EXPANSION PLAN FOR EVACUATING ALL OFFSHORE WIND

The problem is seen as a discrete OTEP problem where the objective is to minimise the total investment cost for each concept. The investment cost is calculated as the sum of the cable cost and offshore platform cost. An

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additional cost is considered for landing an extra cable on a platform. A branch-and-bound algorithm is used to solve this mixed-integer linear programming problem. This approach was already described in D1.6 but is reminded here for the sake of clarity.

- In order to be able to derive accurately costs from recent projects, discrete ratings are used. Note that, in a symmetric monopolar or in a bipolar configuration, the rating of a circuit is twice the rating of a cable.
- One of the main challenges of the formulation is that the time horizon from 2025 to 2050 is simulated. OTEP problem will be formulated as a multi time-steps optimisation problem.
- No load flows are executed in the OTEP phase. It is assumed that the flow can be fully controllable (which is inherently true when there is no meshing). Therefore, load flows will be performed in a second stage to verify the topologies as described in Section 5.3.3.

OTEP formulations were traditionally developed for the expansion of existing grids, with a limited number of candidate circuits reinforcing critical areas or corridors of the grid identified beforehand. Therefore, even if studied networks could have several hundreds of nodes, the number of candidate circuits is usually limited to several tens. The case of the development of a MOG in the North Seas translates in almost a “greenfield” from a power system point of view (i.e. only few existing connections far from the shore). It is thus not possible to execute a “first pass” in the network to identify the few most suitable locations for investment and thereby reduce the number of candidate circuits. Nevertheless, it would be intractable to consider as candidate circuits each direct connection between any pair of nodes. Indeed, the number of binary variables is proportional to the number of candidate circuits and MIP problems do not scale well to a large number of binary variables. Consequently, a pragmatic approach is needed to identify appropriate candidate circuits.

One of the main challenges in the determination of the candidate circuits comes from the assumption taken on the onshore connection. In this study, it has been assumed that each onshore connection can have a hosting capacity of maximum 4 GW, which means that many onshore candidates are required to fully evacuate the forecasted wind production. It is worth noting that the onshore hosting capacity constraint might significantly influence the topology of the MOG, as outlined in Section 5.5.

5.3.1.2.1 SET OF CANDIDATE LINES

The sets of candidate lines are chosen accordingly to the philosophy of each concept. It is worth noting that the BAU and HUB concepts consider each offshore platform individually. However, due to the high complexity of the problem for the NAT and EUR concepts, clusters are used. These clusters are calculated using a maximum distance of 100 km between any two points, which means that if an HVDC platform is built in the middle of the cluster, all windfarms will be located at less than 50 km of the HVDC platform. The exact configuration of the AC network is not in the scope of this Chapter which aims at having a realistic representation of the overall offshore HVDC grid topology, but this is taken into account already for the cost estimation. For each concept, the following rules are used:

- For the BAU concept, the set of candidate lines includes only connections from offshore nodes to onshore nodes of the same country. No connection between offshore nodes is allowed. Four cable ratings are used, meaning that there are at most four candidates between any two points.

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- For the NAT concept, connections between offshore nodes of the same country are also allowed.
- For the EUR concept, connections between any two points having the same voltage level are allowed.
- For the HUB concept, no connection between offshore wind nodes is allowed. It is only allowed for an offshore node to be connected to a “hub” (or artificial island) or directly to shore. The hubs can be connected to another hub or to shore. Depending on the distance, AC connections are also allowed between windfarms and artificial islands.

For the sake of illustration, the sets of candidate lines for the four concepts are shown in Figure 5-3 to Figure 5-6. In these figures, the red dots represent offshore nodes while the blue dots represent onshore nodes. The HUB case is an exception as the offshore hub nodes (i.e. artificial islands) are represented by blue dots too. The yellow lines are 525kV cables and the blue lines 320kV cables.

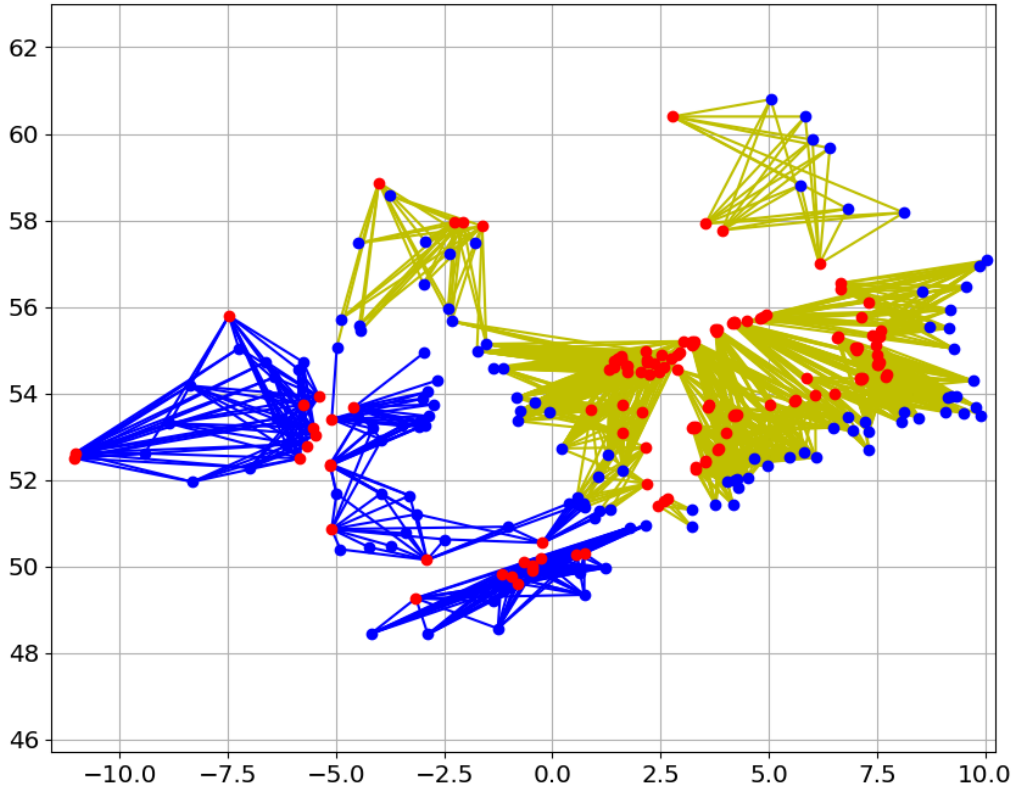

Figure 5-3 - Set of candidates for BAU.

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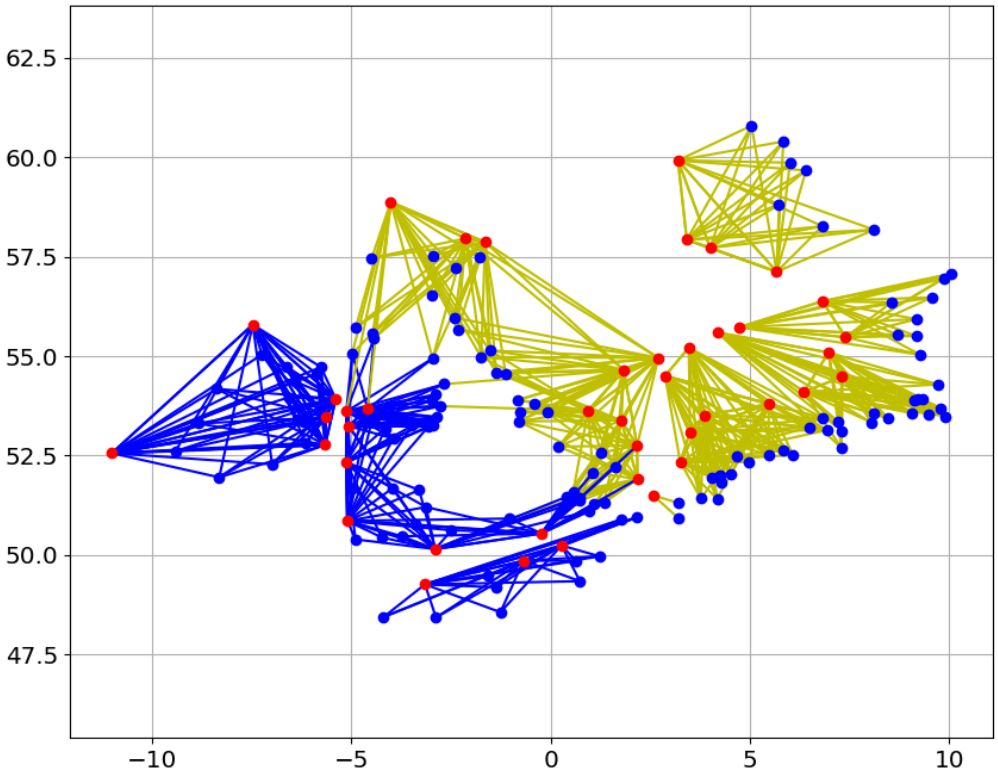

Figure 5-4 - Set of candidates for NAT.

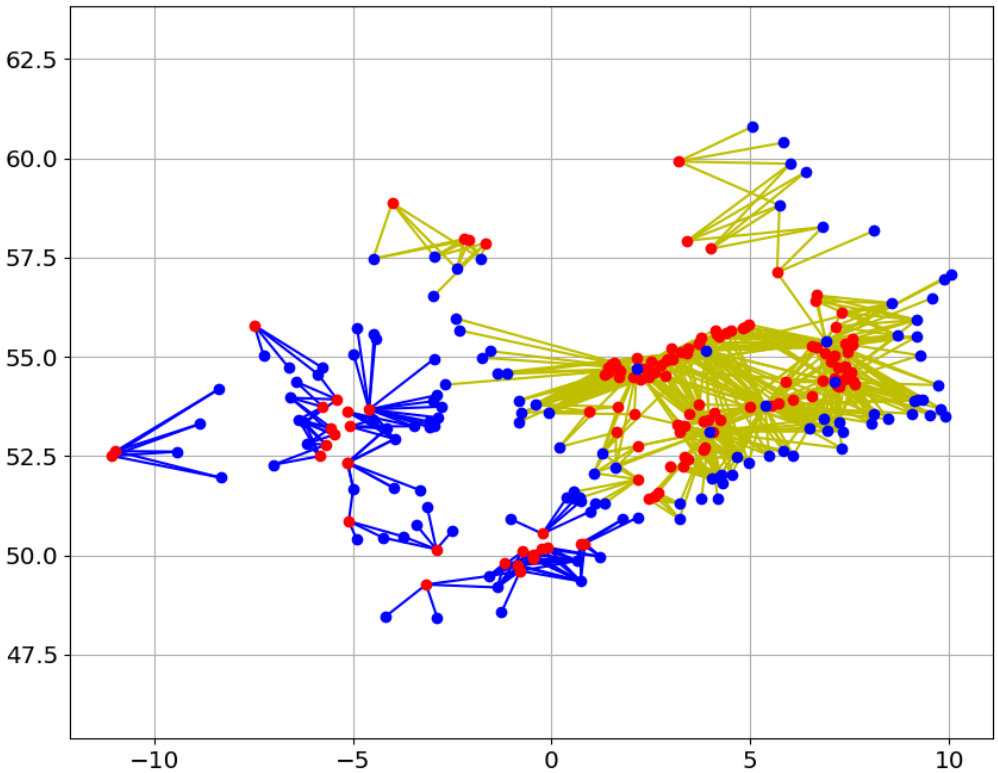

Figure 5-5 - Set of candidates for HUB.

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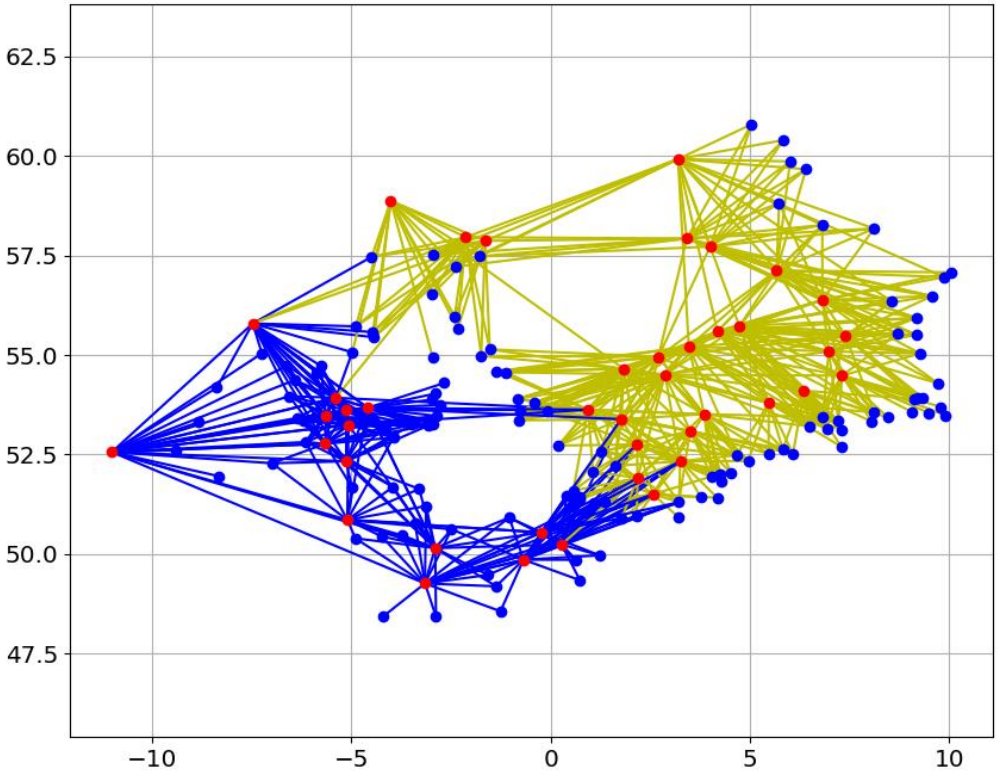

Figure 5-6 - Set of candidates for EUR.

5.3.1.2.2 MATHEMATICAL FORMULATION

The following indices, sets, variables and parameters will be used to formalise the OTEP problem:

- **Indices and sets**
  - $t \in [1, T]$: Index and set of years
  - $k \in K$: Index and set of HVDC circuits
  - $n_w \in N_w$: Index and set of offshore nodes
  - $n_c \in N_c$: Index and the set of onshore nodes (connection points of the offshore grid on the shores)
  - $n \in N = N_w \cup N_c$: Index and set of nodes (offshore and onshore)
- **Variables**
  - $x_{k,t}$: Binary variable indicating the presence or not of HVDC circuit k during year t
  - $y_{n_w,t}$: Binary variable indicating the presence or not of candidate offshore substation at node n_w during year t
  - $p^f_{k,t}$: Power flow in HVDC circuit k for the peak offshore wind generation during year t [p.u.]
  - $p^l_{n_c,t}$: Power evacuated from the offshore grid at the onshore node n_c during year t [p.u.]
- **Parameters**
  - T: Number of years in the planning horizon
  - P_k: Maximum power flow in HVDC circuit k
  - P_{n_c}: Maximum power evacuation (hosting capacity) at onshore node n_c

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- P_{n_w}: Peak offshore production at offshore node n_w
- $I_{n,k}$: Incidence matrix whose elements are equal to 1 if the HVDC circuit k starts at node n, -1 if it ends at node n, and 0 otherwise
- $\gamma_{k,t}$: Discounted cost of HVDC circuit k at year t
- $\delta_{n_{w,t}}$: Discounted cost of an offshore substation at node $n_w$at year t
- M: Sufficiently high number needed to express the need of offshore substations in a linear way, chosen at 200 for this study
- ρ: Actualization rate
- τ: Lifetime of a DC circuit, in years

On the basis of these notations, the optimisation problem can be formulated as follows:

- Objective function:

$$\text{Min} \sum_{k\in K} \sum_{t\in[1,T]} \gamma_{k,t}(x_{k,t} - x_{k,t-1}) + \sum_{n\in N} \sum_{t\in[1,T]} \delta_{n,t}(y_{n,t} - y_{n,t-1}) \tag{5-1}$$

- Such that:

$$\sum_{k\in K} I_{n_w,k}\, p^f_{k,t} = P_{n_w}\ \forall n_w, t \tag{5-2}$$

$$\sum_{k\in K} I_{n_c,k}\, p^f_{k,t} + p^l_{n_c,t} = 0\ \forall n_c, t \tag{5-3}$$

$$0 \le p^l_{n_c,t} \le P_{n_c}\ \forall n_c, t \tag{5-4}$$

$$-x_{k,t}\, P_k \le p^f_{k,t} \le x_{k,t}\, P_k \forall k, t \tag{5-5}$$

$$x_{k,t} \ge x_{k,t-1}\ \forall k, t \tag{5-6}$$

$$\sum_{k\in K} |I_{n_w,k}|\, x_{k,t} - 1 \le M\, y_{n_w,t}\ \forall n_w, t \tag{5-7}$$

$$y_{n_w,t} \ge y_{n_w,t-1}\ \forall n_w, t \tag{5-8}$$

Equation (5-1) describes the objective function to minimise, the actualised total investment cost. This investment cost is the sum of the costs of the HVDC circuit and of the costs of the offshore substations. Note that the cost of converters and circuit breakers is not considered in that objective function. For each year, the sum comprises the cost of circuits commissioned that year. Indeed, as $x_{k,t}$ represents the existence of line k at year t, $x_{k,t} - x_{k,t-1}$ gives whether line k was installed at year t or not (with $x_{k,0} = 0$). The same rationale applies for the substations. Equation (5-2) enforces the power balance at offshore nodes: the peak offshore production at offshore node n_w must be entirely evacuated by HVDC circuits connected to that node. Equation (5-3) enforces the power balance at onshore nodes: the algebraic sum of power flows on HVDC circuits connected to the onshore node n_c must be absorbed by HVDC converters connected to that onshore node. Equation (5-4) limits the power that must be absorbed by an onshore node to the hosting capacity of the onshore grid. Equation (5-5)constraints the power flow through HVDC circuits to their nominal rating. Equation (5-6) indicates that once a HVDC circuit has been commissioned, it cannot be decommissioned later on[26]. Equation (5-7) enforces the commissioning of an offshore substation at the offshore node n_w if more than one HVDC circuit is connected to

[26] In theory, a circuit or a substation could be decommissioned, but with a specific cost that is not considered in the model as it stands: considering that $x_{k,t}$ could be lower than $x_{k,t-1}$ would lead to a negative cost in the objective function which is unrealistic.

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that offshore node. Finally, equation (5-8) indicates that once an offshore substation has been commissioned, it cannot be decommissioned later on.

This algorithm will try different combinations of cables and cable ratings until finding a near optimum solution. The complexity of this combinatorial optimisation problem grows exponentially with the number of candidate lines. In the context of developing a new transmission grid, it is clear that the complexity of the problem is a real challenge. A “branch and bound” technique is used to search amongst the solution set. This technique does not explore all the possible solutions and is widely used in mixed-integer linear programming problems.

5.3.2 STEP 2 - SECONDARY OPTIMISATION: OPTIMISATION OF THE INTERCONNECTION CAPACITY BETWEEN COUNTRIES

The optimisation of the interconnectors is performed using a market model. This model takes as input the offshore topology and location of wind farms. The load profile and generation profile are directly taken from the ENTSO-E scenarios. The goal is to determine the optimum needs for interconnectors in each concept. In the BAU these interconnectors will be from onshore to onshore while for the other concepts, the interconnectors can use the HVDC lines of the offshore grid. This second step should observe a cable length reduction in the meshed solutions compared to the BAU concept. It must be noted that this second step is mandatory to be able to compare each concept on a fair basis.

The optimised interconnection capacities come from a linear optimisation and have therefore to be converted to more specific projects, meaning that the value provided by the market simulation has to be converted to a certain number of cables having a specific rating. Knowing more in details the number of cables, rating and length is required in order to have a detailed view of the complete offshore grid topology and total cost.

The optimisation of the interconnection between countries takes into consideration both the investment cost and the economic benefits of the interconnection. This optimisation is performed using a market simulation model based on the ENTSO-E scenarios data. The expansion of the interconnectors is the only expansion possibility in the model, which already considers the planned expansion from the ENTSO-E scenarios. Therefore, the model invests in the interconnectors if the investment cost plus the electricity cost from another country is cheaper than the national production cost. The overall flowchart of the secondary optimisation can be seen in Figure 5-7.

For the purpose of this project, mainly publicly available data are used. The ENTSO-E scenario datasets used in the 2018 TYNDP have been developed for a similar purpose, i.e. the analysis of network assets, and therefore provide a good starting point. These data also have the added benefit of familiarity to PROMOTioN’s stakeholders.

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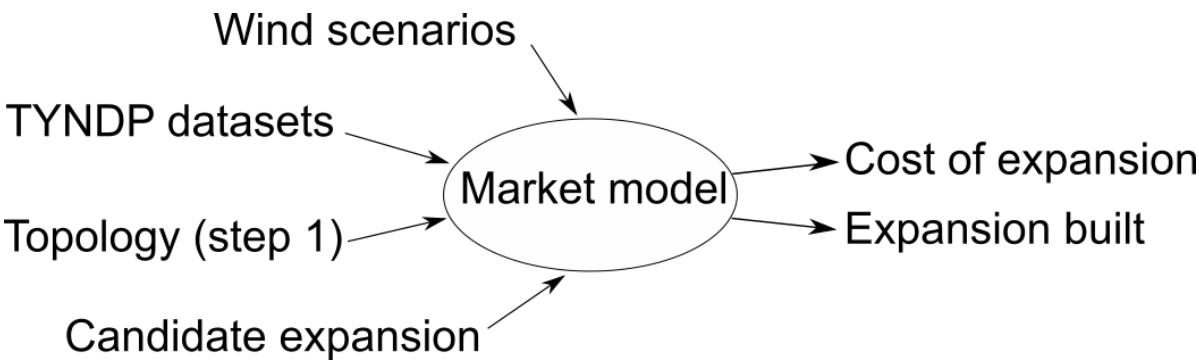

Figure 5-7 - Flowchart of step 2 of the methodology.

5.3.2.1 REPRESENTATION OF THE GRID BY A MULTI-AREA MODEL

The network is represented by a multi-area model. This means that the transmission grid is simplified to Net Transfer Capacity (NTC) between areas and that each area is represented by a single node. The market model is based on the publicly available ENTSO-E dataset.

Figure 5-8 illustrates the ENTSO-E interconnections between the countries within the scope of PROMOTioN. Finland, the northern parts of Norway and of Sweden are not shown.

Some of the interconnections shown in Figure 5-8 are open for transfer capacity investment: Belgium to West Denmark, Belgium to the United Kingdom, Belgium to Southern Norway, Germany to Eastern Denmark, Germany to the United Kingdom, Germany to Southern Sweden, the German part of the Krieger Flag platform to the Danish part of the same platform, West Denmark to France, to the United Kingdom, to the Netherlands, to Southern Sweden and to Sweden, France to Southern Norway, the United Kingdom to Ireland, to Northern Ireland to the Netherlands and to Southern Norway, and the Netherlands to Southern Norway. Investments in the transfer capacity of those transmission lines only occur if the model determines that this investment is economically viable.

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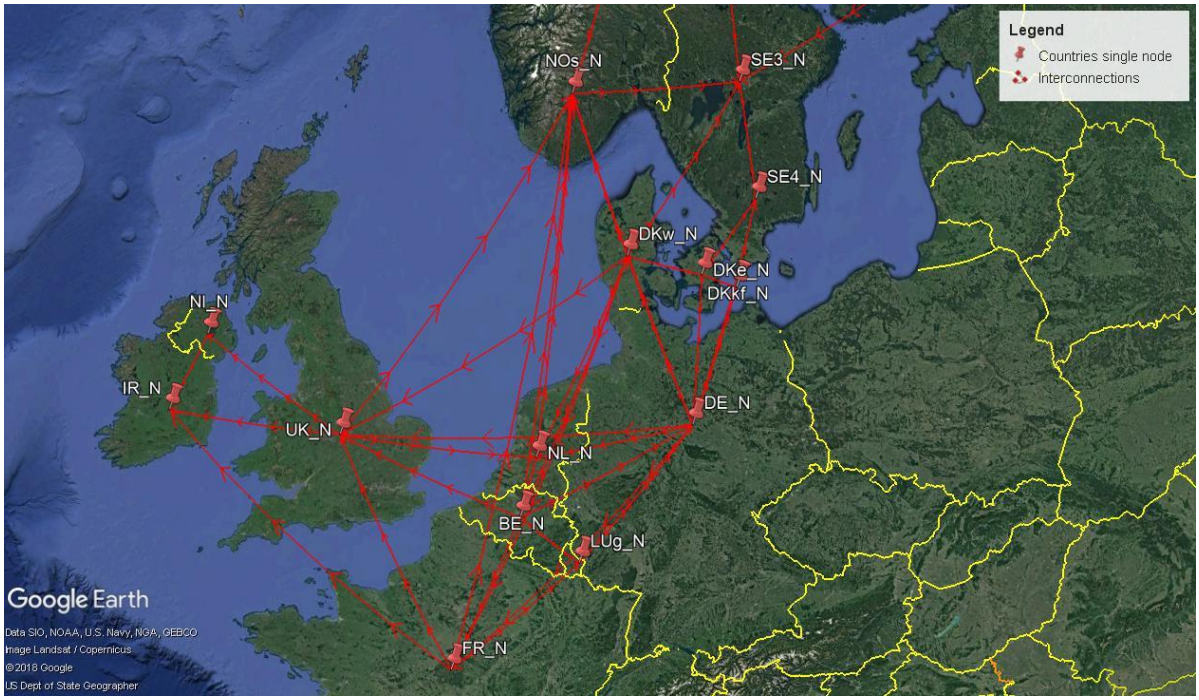

Figure 5-8 - Map of the interconnections between countries planned according to the ENTSO-E scenarios or open for transfer capacity investment.

Only the offshore grid is represented in detail to analyse the differences between the grid topologies. The grid topology modelled is shown in Figure 5-9 for the BAU topology, in Figure 5-10 for the NAT topology, Figure 5-11 for the HUB topology and in Figure 5-12 for the EUR topology. The transmission lines candidate for transfer capacity expansion are coloured in cyan in the following figures. The direct country-to-country transmission lines candidates for transfer capacity expansion are not shown on these Figures but are maintained as candidates. This approach lets the market simulation software determine which candidate transmission lines are the most cost-effective for transfer capacity expansion, including both candidate offshore transmission lines and candidate direct country-to-country transmission lines.

It is worth noting that only offshore HVDC transmission line candidates are considered in this study. This is done in order to compare the benefits of the offshore grid depending for each grid development concept. However, the scope of this study is not to optimize both offshore and onshore grid developments.

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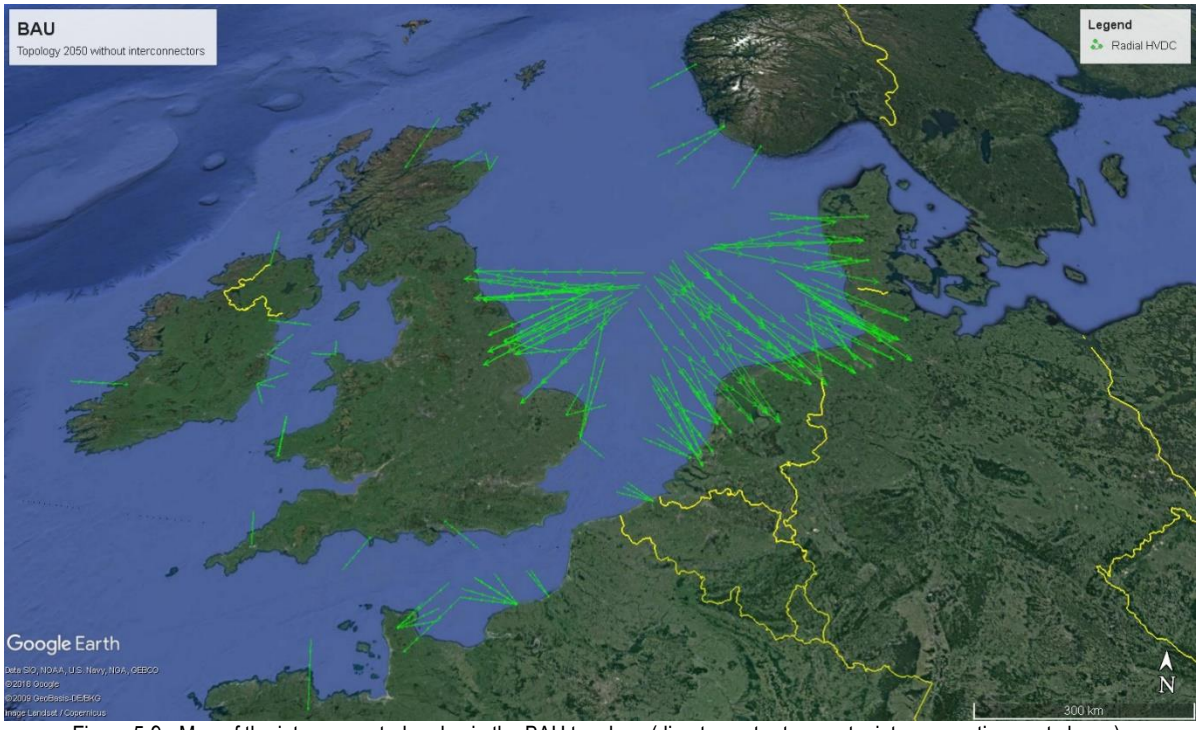

Figure 5-9 - Map of the interconnected nodes in the BAU topology (direct country-to-country interconnections not shown).

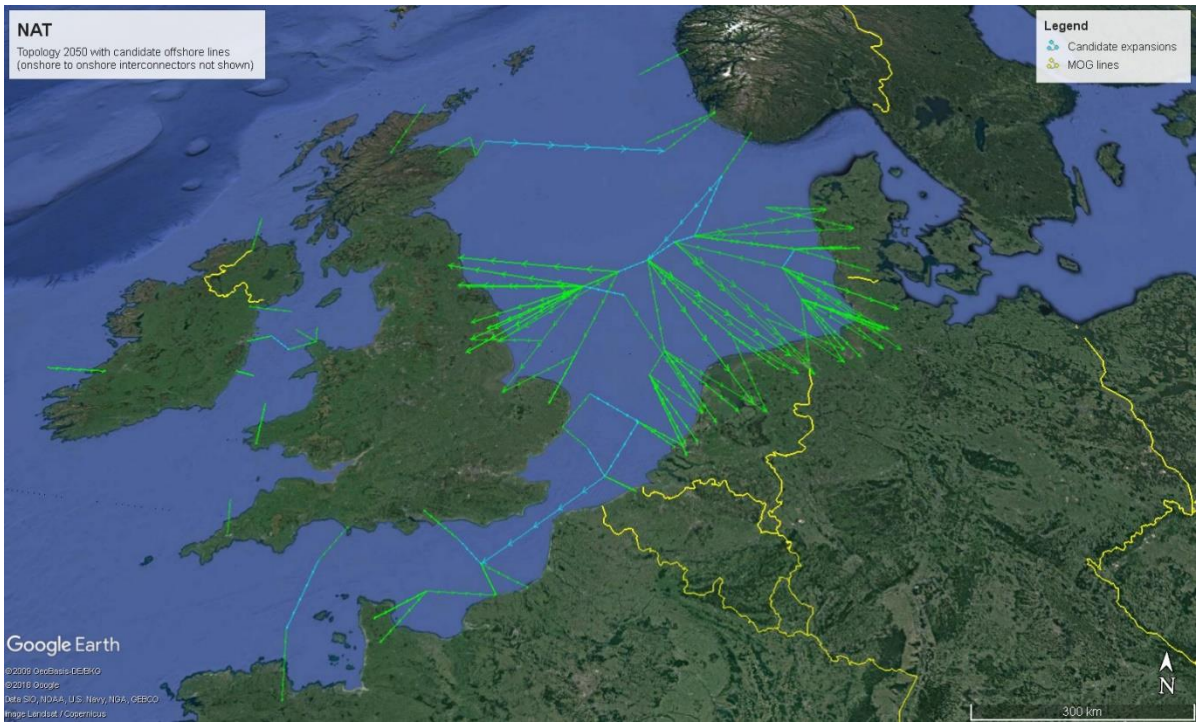

Figure 5-10 - Map of the interconnected nodes in the NAT topology (direct country-to-country interconnections not shown).

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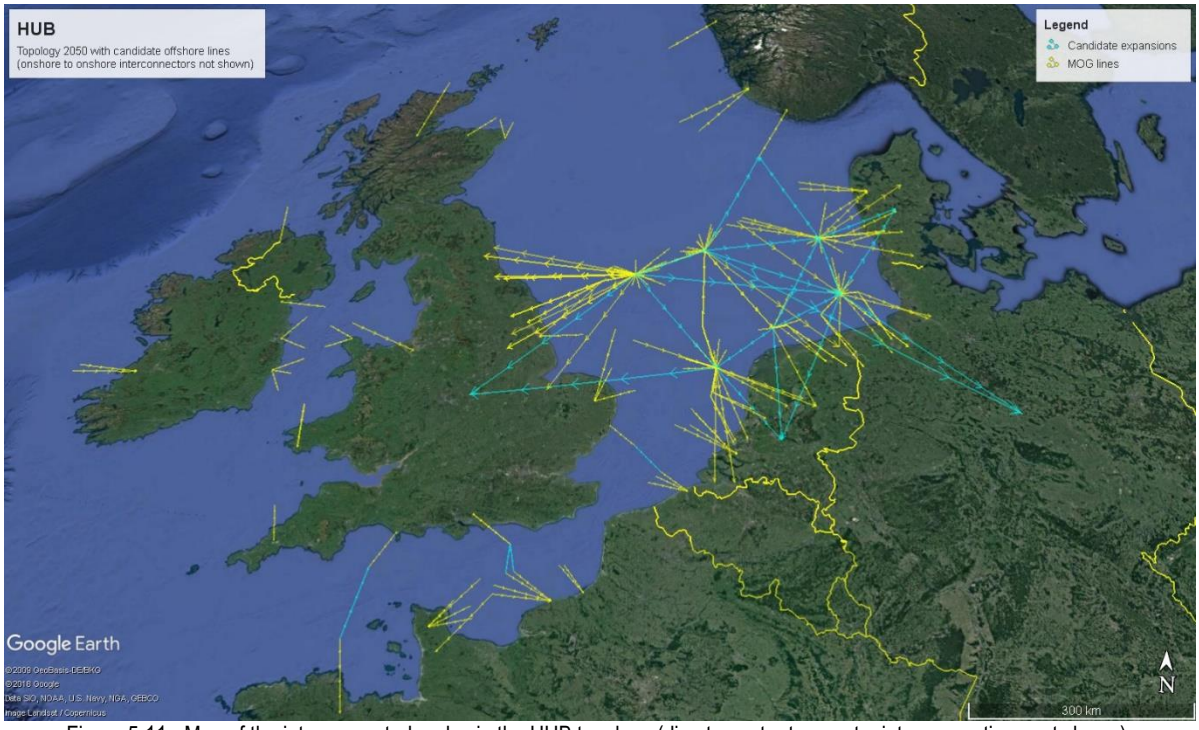

Figure 5-11 - Map of the interconnected nodes in the HUB topology (direct country-to-country interconnections not shown).

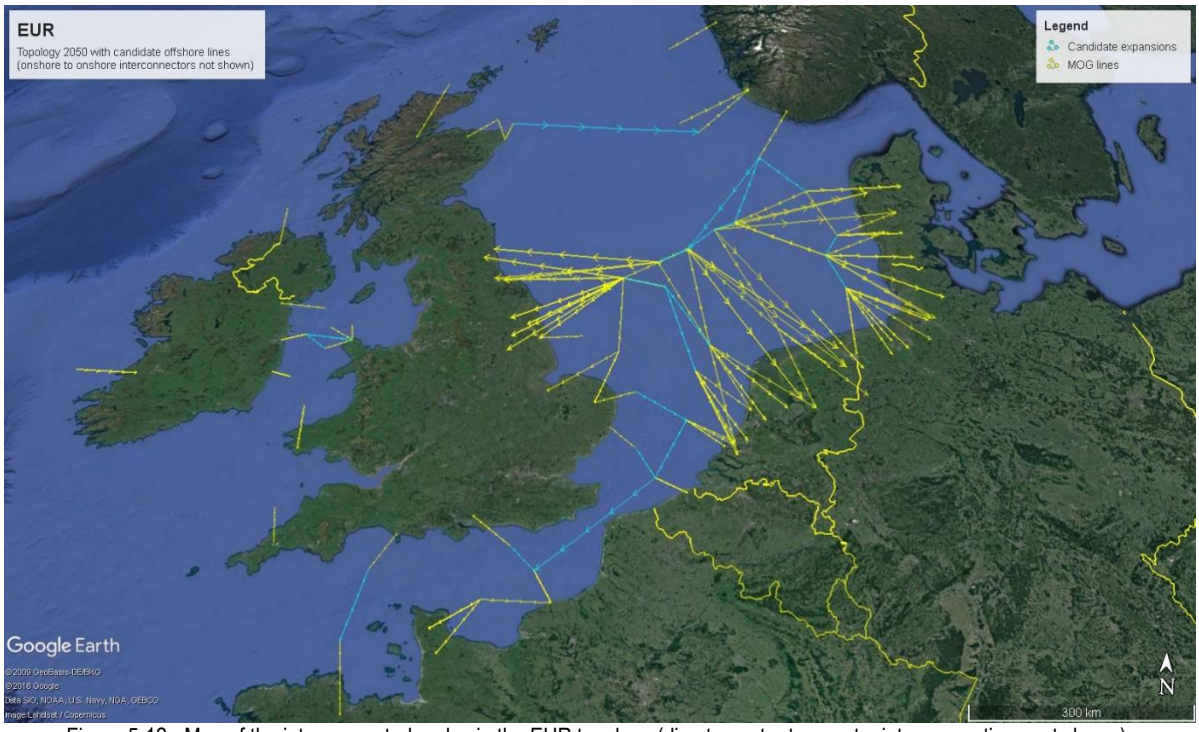

Figure 5-12 - Map of the interconnected nodes in the EUR topology (direct country-to-country interconnections not shown).

5.3.2.2 ENTSO-E SCENARIOS

The objective of the TYNDP has been the development of Europe's electrical network to achieve clean future for the power system by 2050 in a cost-efficient way while maintaining system security.

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The scenarios developed in the TYNDP for 2020 and 2025 are labelled Best-Estimate as the level of uncertainty is low on that horizon. For 2030 and 2040, several scenarios are considered:

- **Sustainable Transition (ST):** The existing infrastructure is maximised, and the targets are reached using national regulation, emission trading schemes and subsiding. This scenario involves the replacement of coal and lignite by gas in the power sector. The load progresses more slowly than the other scenarios as the electrification of the transport and heating occurs at a slower pace. Data for this scenario are available for 2030 and 2040.
- **Distributed Generation (DG):** This scenario considers a move away from centralised generation and to more small-scale generation, a partial switch of fuels for heating purposes and the use of batteries including for increasingly electric vehicle numbers. Data for this scenario are available for 2030 and 2040.
- **Global Climate Action (GCA):** A world-wide effort towards full decarbonisation is assumed in this scenario. The power sector relies on large-scale renewables and nuclear power to achieve this objective. Heating systems also become more electrified. Data for this scenario are only available for 2040.

As PROMOTioN considers a massive development of offshore wind capacity in the North Seas, the GCA scenario is the best fit, for the High wind scenario, in terms of energy demand and thermal generation capacities in 2040. There is however no data for this GCA scenario in 2030. The TYNDP considers that the ST scenario in 2030 is the best approach to lead to the GCA scenario in 2040. It is therefore used for the 2030 input data.

For 2035, 2045 and 2050, the TYNDP does not contain scenarios. The total energy produced by countries of the North Seas originating from solar PV, offshore wind and onshore wind generations is linearly extrapolated from the ST2030 and the GCA2040 scenarios to compute the capacities of these 3 renewable energy sources in those years. The hourly demand is linearly extrapolated for each country from the hourly demand profiles available for 2020, 2025, 2030 and 2040.

In addition to the generation capacities, the NTC values between countries are also taken from the TYNDP scenarios. For the sake of clarity, the HVDC undersea projects considered are shown in Table 5-1.

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 691714.

Table 5-1 - List of subsea ables considered in the NTC values.

	BE	DK	DE	GB	FR	IE	NI	NL	NO	SE
BE				NEMO (1 GW)						
DK		Great Belt Power Link (600 MW)	Kontek (600 MW) Kriegers Flak CGS (400 MW)	Viking (1.4 GW)				COBRAcable (700 MW)	Skagerrak 1-4 (1640 MW)	Konti-Skan (550 MW)
DE		Kontek (600 MW) Kriegers Flak CGS (400 MW)		NeuConnect (1.4 GW)					NordLink (1.4 GW)	Baltic Cable (600 MW)
GB	NEMO (1 GW)	Viking (1.4 GW)	NeuConnect (1.4 GW)		IFA2000 (2 GW) IFA2 (1 GW) ElecLink (1 GW) France-Alderney-Britain (1.4 GW) GridLink (1.4 GW)	East West (500 MW)	Moyle (500 MW)	BritNed (1 GW)	North Sea Link (1.4 GW) NorthConnect (1.4 GW)	

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 691714.

	BE	DK	DE	GB	FR	IE	NI	NL	NO	SE
FR				IFA2000 (2 GW) IFA2 (1 GW) ElecLink (1 GW) France-Alderney-Britain (1.4 GW) GridLink (1.4 GW)						
IE				East West (500 MW)						
NI				Moyle (500 MW)						
NL				BritNed (1 GW)					NorNed (700 MW)	
NO		Skagerrak 1-4 (1640 MW)	NordLink (1.4 GW)	North Sea Link (1.4 GW) NorthConnect (1.4 GW)						
SE		Konti-Skan (550 MW)	Baltic Cable (600 MW)							

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 691714.

5.3.2.3 COMBINING OFFSHORE WIND AND ENTSO-E SCENARIOS

The ENTSO-E scenarios data are used as input for this study. The PROMOTioN offshore wind generation is however larger than the assumed offshore wind generation of the ENTSO-E scenarios for the GCA ("High") and ST ("Central") scenarios, as shown in Figure 5-13.

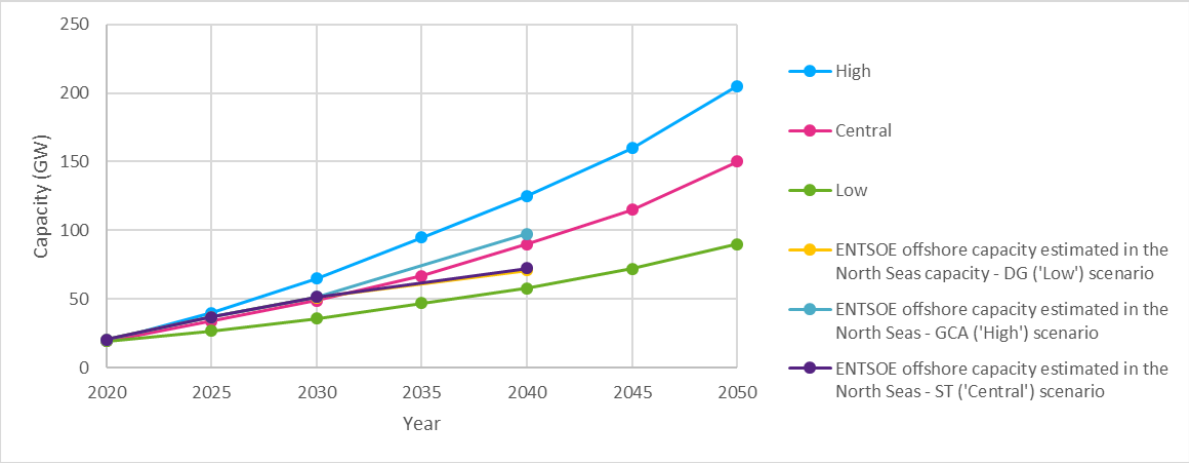

Figure 5-13 - Offshore wind capacity targets of PROMOTioN and estimated offshore wind capacity in the North Seas of the ENTSO-E scenarios.

The PROMOTioN offshore wind generation is inserted in the ENTSO-E scenarios by reducing the onshore wind generation and the solar PV generation of each country. The following constraints are respected:

- The total onshore wind, offshore wind and solar PV generation across all countries is maintained constant.
- The ratio of solar PV to onshore wind generation is kept identical after insertion of the offshore wind generation in the generation mix of each country.
- The RES targets of offshore capacities in the North Seas are met.

The approach follows the following steps to insert the North Seas offshore wind capacity in the ENTSO-E scenarios:

- **Step 1: Definition of the target North Seas offshore wind capacities**
- **Step 2: Sizing of the offshore wind capacities in the other seas of the countries**
    - Other seas may be the Atlantic Ocean, the Arctic Sea, and the Baltic Sea.
    - As the ENTSO-E data do not contain geographical details of the locations of the offshore wind capacities, the shares of the offshore capacities in the North Seas and in other seas are estimated for each country.
    - The offshore wind capacities in the other seas are calculated from the target North Seas offshore wind capacities (see Step 1) and from the estimated shares of the offshore capacities in the North Seas and in the other seas.
- **Step 3: Calculation of the onshore and offshore energy output for each country**
    - The onshore and offshore energy output for each country are calculated from the onshore and offshore capacity of the onshore and offshore load factors associated to each country.
- **Step 4: Calculation of the total energy generated by solar PV and onshore wind**

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- The total energy generated by the offshore wind capacities calculated in Steps 1 and 2 is subtracted from the ENTSO-E RES (except for hydro) total generated energy to obtain the energy generated by the solar PV and by the onshore wind.
- For 2050, the ENTSO-E does not provide the total RES energy production. The ratio of the RES energy growth from 2030 to 2040 across all countries of the scope is applied between 2040 and 2050 to calculate the 2050 RES energy, the solar PV and wind onshore energies.
- The 2030 GCA scenario is considered identical to the 2030 ST scenario, as the ENTSO-E data do not include a 2030 GCA scenario.

- **Step 5: Calculation of the solar PV and onshore wind capacities**
  - The ratio of the calculated energy of total solar PV and onshore wind on the ENTSO-E total energy of solar PV and onshore wind is used to scale the solar PV and onshore wind capacities proportionally to their energy contributions in the ENTSO-E scenarios.

These 5 steps are illustrated in Figure 5-14.

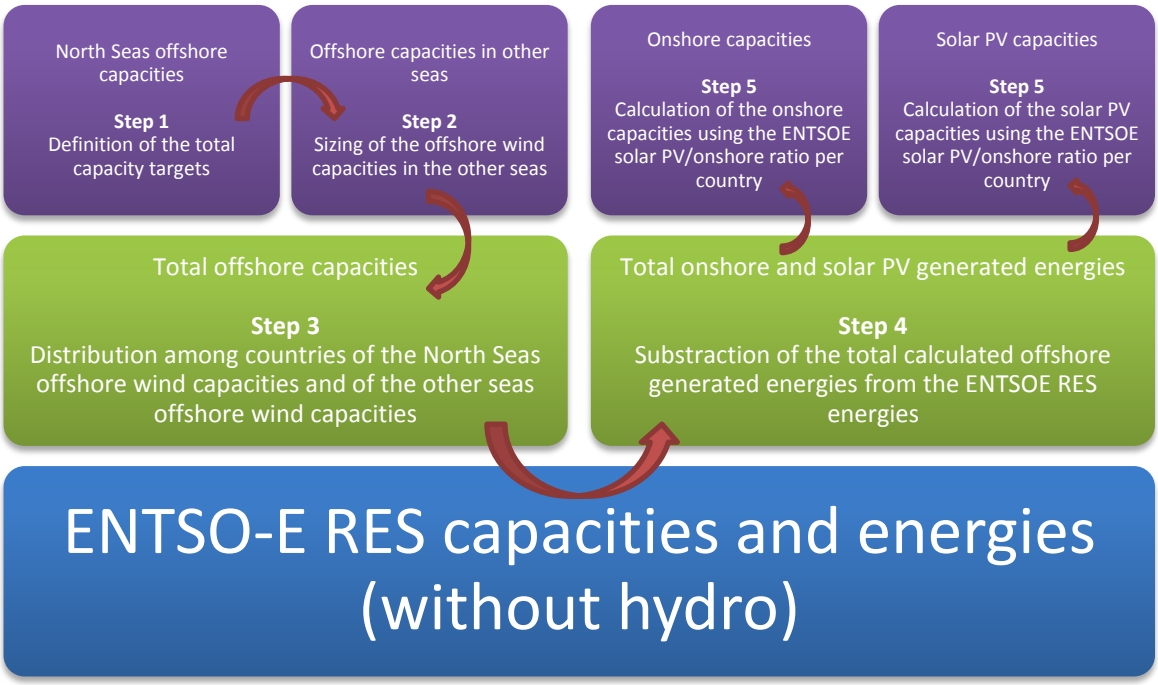

Figure 5-14 - Steps to calculate the offshore, onshore and solar PV capacities.

The Step 1 offshore wind capacities targets in the North Seas are listed in Table 5-2. The 2020 values originate from the ENTSO-E wind offshore capacities. The wind offshore capacities beyond 2020 are the sum of capacities added by PROMOTioN and of the ENTSO-E wind offshore capacities of 2020.

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Table 5-2 – PROMOTioN offshore wind capacities targets in the North Seas.

EQUIVALENT ENTSO-E SCENARIO	LOW (DG)				CENTRAL (ST)				HIGH (GCA)			
PROMOTioN Capacity per year (GW)	2020	2030	2040	2050	2020	2030	2040	2050	2020	2030	2040	2050
Belgium	2,3	2,3	2,7	3,2	2,3	3,4	4,5	5,2	2,3	3,7	6,0	6,0
Denmark	1,2	1,8	2,3	3,6	1,2	2,2	3,6	10,1	1,2	3,0	8,6	17,8
Finland	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
France	0,0	0,0	1,6	2,5	0,0	0,4	2,4	5,4	0,0	0,9	6,0	10,7
Germany	6,2	12,7	17,1	26,0	6,2	13,6	29,2	44,8	6,2	16,7	32,6	47,9
Great Britain	8,2	15,2	22,1	34,3	8,2	19,0	32,2	53,7	8,2	23,5	39,4	60,8
Ireland	0,0	1,0	1,1	1,7	0,0	1,5	1,7	2,8	0,0	2,1	2,8	5,8
Luxembourg	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
Norway	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,4	4,0
Sweden	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
The Netherlands	1,7	3,0	11,1	18,7	1,7	8,9	16,5	28,0	1,7	16,5	31,9	52,2
Total	**19,6**	**36,0**	**58,0**	**90,0**	**19,6**	**49,0**	**90,1**	**150,0**	**19,6**	**66,4**	**127,7**	**205,2**

Table 5-3 lists the wind offshore capacities in seas other than the North Seas as a result of Step 2 and Step 3.

Table 5-3 - PROMOTioN offshore wind capacities in the seas other than the North Seas.

EQUIVALENT ENTSO-E SCENARIO	LOW (DG)				CENTRAL (ST)				HIGH (GCA)			
PROMOTioN Capacity per year (GW)	2020	2030	2040	2050	2020	2030	2040	2050	2020	2030	2040	2050
Belgium	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
Denmark	0,5	0,8	1,0	1,5	0,5	0,9	1,5	4,3	0,5	1,3	3,7	7,6
Finland	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
France	0,0	0,0	6,4	10,0	0,0	1,6	9,6	21,6	0,0	3,6	24,0	42,8
Germany	1,1	2,2	3,0	4,6	1,1	2,4	5,2	7,9	1,1	2,9	5,8	8,5
Great Britain	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
Ireland	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
Luxembourg	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
Norway	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
Sweden	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
The Netherlands	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
Total	**1,6**	**3,0**	**10,4**	**16,1**	**1,6**	**4,9**	**16,3**	**33,8**	**1,6**	**7,8**	**33,4**	**58,9**

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 691714.

Step 4 results in a different energy production between RES technologies. Table 5-4 lists the total yearly energy produced by each RES technology (solar PV, onshore wind and offshore wind in the North Seas and in other seas).

Table 5-4 - Energy produced by RES in the PROMOTioN market simulation.

EQUIVALENT ENTSO-E SCENARIO	LOW (DG)				CENTRAL (ST)				HIGH (GCA)			
PROMOTioN Energy per year (TWh)	2020	2030	2040	2050	2020	2030	2040	2050	2020	2030	2040	2050
Solar PV	96	259	409	603	96	167	180	182	96	181	304	518
Offshore wind North Seas	60	110	178	276	60	149	275	461	60	201	392	637
Offshore wind other seas	5	9	38	59	5	16	59	124	5	27	126	222
Onshore wind	227	357	496	696	227	333	377	381	227	305	398	652
Total	**388**	**735**	**1121**	**1634**	**388**	**666**	**891**	**1148**	**388**	**715**	**1220**	**2029**

Finally, Table 5-5 and Table 5-6 list the onshore wind capacities and solar PV capacities resulting from Step 5.

Table 5-5 - PROMOTioN onshore wind capacities.

EQUIVALENT ENTSO-E SCENARIO	LOW (DG)				CENTRAL (ST)				HIGH (GCA)			
PROMOTioN Capacity per year (GW)	2020	2030	2040	2050	2020	2030	2040	2050	2020	2030	2040	2050
Belgium	2,5	3,8	13,3	19,6	2,5	3,5	4,6	4,7	2,5	4,1	6,6	11,2
Denmark	4,5	6,4	9,7	14,4	4,5	6,0	8,2	8,4	4,5	5,3	6,4	10,5
Finland	1,7	2,6	7,9	11,7	1,7	2,5	6,7	6,8	1,7	3,5	6,3	10,7
France	16,9	41,7	58,5	86,3	16,9	38,8	43,8	44,7	16,9	31,2	42,0	71,6
Germany	54,3	67,1	81,4	105,7	54,3	62,5	64,6	64,6	54,3	59,6	71,8	119,0
Great Britain	12,4	18,5	22,4	30,2	12,4	17,2	17,8	17,8	12,4	15,0	18,1	25,8
Ireland	4,2	8,1	9,8	13,2	4,2	7,5	7,8	7,8	4,2	6,6	8,0	12,7
Luxembourg	0,2	0,2	0,5	0,7	0,2	0,2	0,2	0,2	0,2	0,2	0,2	0,4
Norway	2,9	3,8	7,4	10,9	2,9	3,6	4,1	4,2	2,9	4,9	8,6	14,6
Sweden	7,1	12,4	15,5	22,9	7,1	11,5	14,4	14,7	7,1	10,8	14,9	25,4
The Netherlands	5,3	7,7	9,4	13,5	5,3	7,2	7,4	7,4	5,3	6,2	7,5	10,8
Total	**112,0**	**172,3**	**235,8**	**329,0**	**112,0**	**160,6**	**179,6**	**181,3**	**112,0**	**147,3**	**190,3**	**312,6**

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 691714.

Table 5-6 - PROMOTioN solar PV capacities.

EQUIVALENT ENTSO-E SCENARIO	LOW (DG)				CENTRAL (ST)				HIGH (GCA)			
PROMOTioN Capacity per year (GW)	2020	2030	2040	2050	2020	2030	2040	2050	2020	2030	2040	2050
Belgium	4,2	7,9	16,1	23,8	4,2	5,4	5,6	5,6	4,2	9,3	18,8	32,1
Denmark	1,1	5,9	8,0	11,8	1,1	3,1	3,7	3,7	1,1	3,4	6,4	10,9
Finland	0,1	3,3	6,2	9,2	0,1	1,3	1,8	1,9	0,1	2,0	5,1	8,8
France	12,0	47,7	80,1	118,2	12,0	33,7	37,8	38,6	12,0	31,2	51,4	87,5
Germany	50,7	108,5	151,9	224,1	50,7	70,9	73,2	73,2	50,7	77,9	120,7	205,7
Great Britain	17,3	39,7	76,5	112,9	17,3	26,2	27,6	28,2	17,3	23,0	32,1	54,7
Ireland	0,1	5,9	9,7	14,3	0,1	1,0	1,2	1,3	0,1	1,3	3,0	5,1
Luxembourg	0,1	0,4	0,8	1,2	0,1	0,2	0,2	0,2	0,1	0,4	0,9	1,6
Norway	0,0	3,4	6,9	10,1	0,0	0,4	1,1	1,1	0,0	0,9	2,6	4,4
Sweden	0,8	6,2	12,2	18,1	0,8	1,9	2,1	2,1	0,8	2,7	5,7	9,8
The Netherlands	4,5	16,2	19,6	28,4	4,5	12,2	13,9	14,2	4,5	18,1	39,4	67,1
Total	**90,9**	**244,9**	**388,1**	**572,0**	**90,9**	**156,3**	**168,2**	**170,1**	**90,9**	**170,0**	**286,2**	**487,6**

Note that the “Low” scenario corresponds to the ENTSO-E Distributed Generation, which assumes a large development of wind onshore and solar PV generation. This explains the large figures observed for this scenario in comparison with the two other scenarios. The PV profiles are obtained from an average on 11 years of the hourly PV generation from the open Power System Data set[27]. This average ensures that a single exceptional year from a PV production point-of-view is not selected as a basis for the PV power forecast from 2020 to 2050. The Capacity Factors of these profiles are listed in Table 5-7.

Table 5-7 - Solar PV Capacity Factors used in the market simulation model of PROMOTioN.

COUNTRY	SOLAR PV CAPACITY FACTOR
Belgium	0,120
Denmark	0,110
Finland	0,095
France	0,140
Germany	0,120
Great Britain	0,110
Ireland	0,110
Luxembourg	0,130
Norway	0,100
Sweden	0,100
The Netherlands	0,120

[27] https://open-power-system-data.org/

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 691714.

Figure 5-15 shows the solar PV capacity of the ENTSO-E ("EE") and of the PROMOTioN secondary optimisation model ("Adjusted") in the High (GCA) scenario.

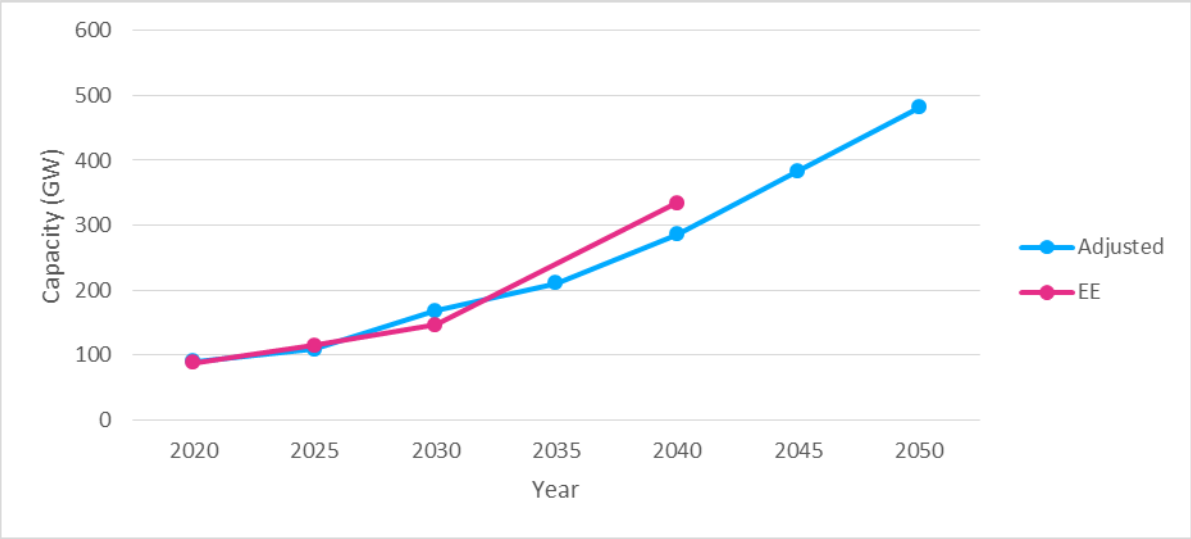

Figure 5-15 - Total solar PV capacities in the ENTSO-E GCA (EE) and PROMOTioN High wind (Adjusted) cases.

The reduction of the solar PV capacity in 2040 in PROMOTioN results from the larger offshore wind capacity PROMOTioN (see Section 5.3.2.5). The total RES energy remaining identical in the ENTSO-E and PROMOTioN scenarios, onshore wind and solar PV capacities are reduced.

5.3.2.4 ONSHORE WIND DEPLOYMENT

The approach of averaging the profile years could not be considered for onshore wind as there is more variability of the onshore wind generation from one year to the next. The onshore wind profiles come also from the open Power System Data set[28]. The Capacity Factors of these profiles are listed in Table 5-8.

Table 5-8 - Onshore Wind Capacity Factors used in the market simulation model of PROMOTioN.

COUNTRY	ONSHORE WIND CAPACITY FACTOR
Belgium	0,247
Denmark	0,259
Finland	0,316
France	0,251
Germany	0,196
Great Britain	0,290
Ireland	0,285
Luxembourg	0,260
Norway	0,287
Sweden	0,248
The Netherlands	0,245

[28] https://open-power-system-data.org/

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 691714.

Figure 5-16 shows the onshore wind capacity of the ENTSO-E ("EE") and of the PROMOTioN secondary optimisation model ("Adjusted") in the High (GCA) scenario.

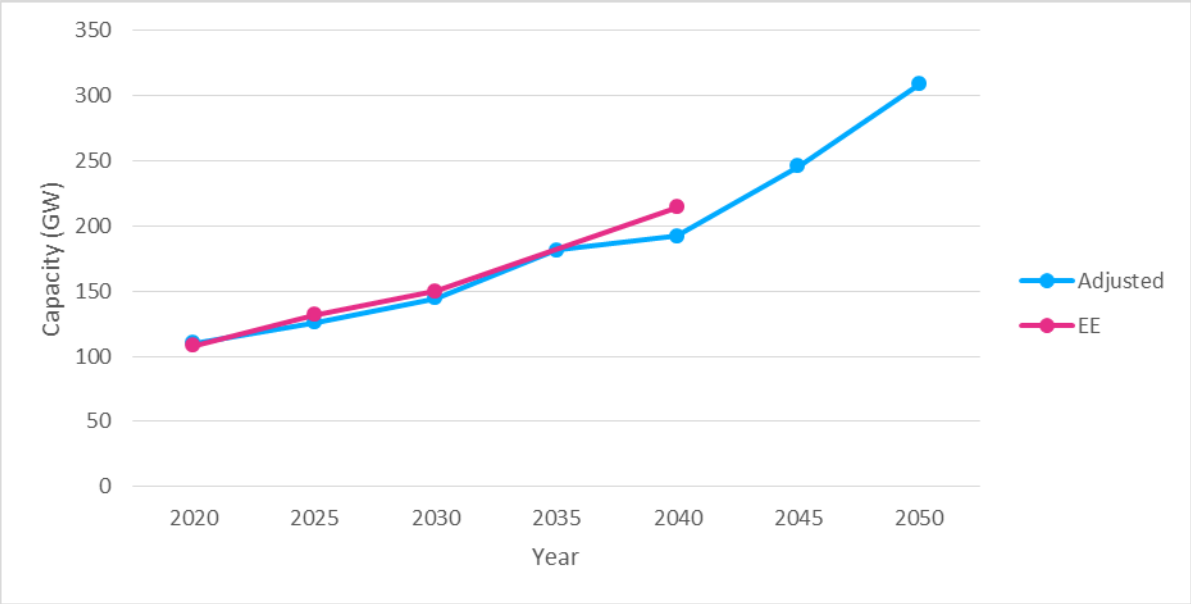

Figure 5-16 - Total onshore wind capacities in the ENTSO-E GCA (EE) and PROMOTioN High wind (Adjusted) cases.

The reduction of the onshore wind capacity in 2040 in PROMOTioN results from the larger offshore wind capacity PROMOTioN (see Section 5.3.2.5). The total RES energy remaining identical in the ENTSO-E and PROMOTioN scenarios, onshore wind and solar PV capacities are reduced.

5.3.2.5 OFFSHORE WIND DEPLOYMENT

The wind profiles for the offshore sites have been extracted from the database developed by the Danish Technical University. A total of 53 locations have been used to cover the North Seas and the likely locations of future windfarms. A dedicated profile has been assigned to each offshore windfarm.

Figure 5-17 shows the total offshore (North Seas and other seas) wind capacity of the ENTSO-E ("EE") and of the PROMOTioN secondary optimisation model ("Adjusted") in the High (GCA) scenario.

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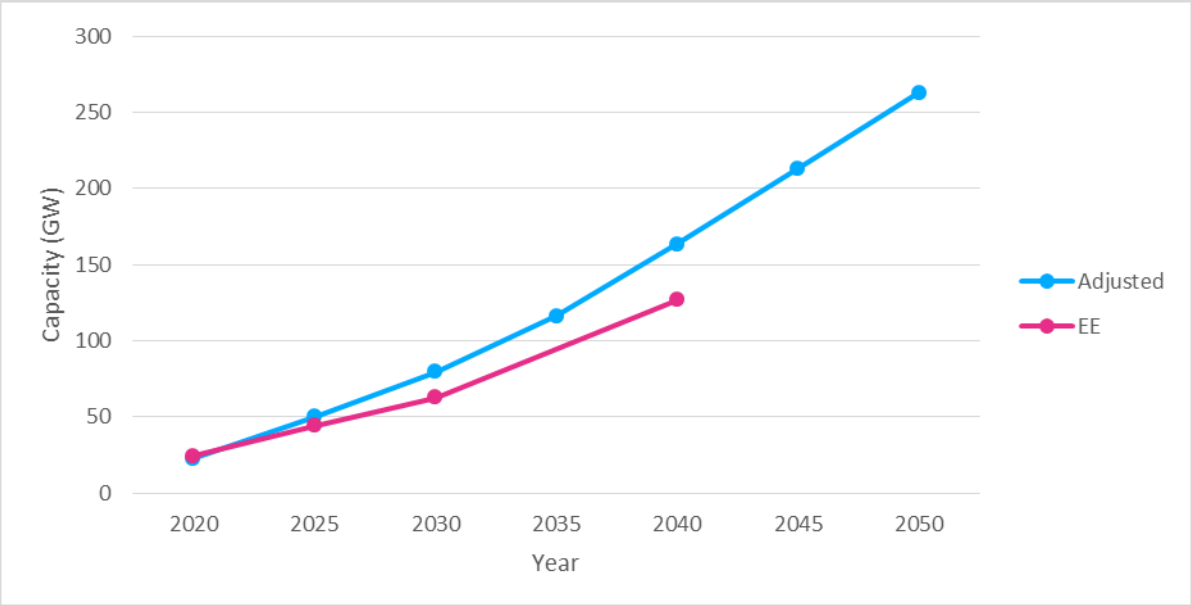

Figure 5-17 - Total (North Seas and other seas) offshore wind capacities in the ENTSO-E GCA (EE) and PROMOTioN High wind (Adjusted) cases.

5.3.2.6 OUTPUTS OF THE SECONDARY OPTIMISATION

As results of the optimisation, the interconnection capacity and expansion costs of each candidate interconnector will be provided.

5.3.3 STEP 3 - STEADY-STATE AND SECURITY ANALYSIS OF THE OPTIMISED INTERCONNECTION CAPACITIES

The optimised interconnection capacities result from a linear optimisation and have therefore to be converted to a more specific project. The capacities built in the market simulation model must indeed be converted to a certain number of cables having a specific rating. Knowing more in details the number of cables, rating and length is required in order to have a detailed view of the complete offshore grid topology.

Load flow calculations are then performed on these developed topologies to verify that the grid is capable of evacuating the offshore energy at full wind production. It is verified that voltages at all bus stay within an acceptable range and that there is no overload on HVDC cables. For the sake of understanding, the security analysis is described using illustrative examples of multi-terminal DC topologies in Section 5.3.3.1. Another important aspect when performing security analysis is to determine representative operating conditions. A method to determine the most representative offshore production pattern from historical data is presented in Section 5.3.3.2.

5.3.3.1 SECURITY ANALYSIS ON MULTI-TERMINAL DC (MTDC) TOPOLOGIES

Three multi-terminal grid topologies considered in the study are shown in Figure 5-18. These topologies have been identified based on the National Distributed Hubs concept. Namely, the offshore wind power hubs export all their power to their corresponding national onshore grid. Nevertheless, loose interconnections between the

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onshore hubs are also envisaged to encourage some exchange between the various onshore grids. GB, N44 and CE stand for the British, Nordic and Continental Europe systems, respectively.

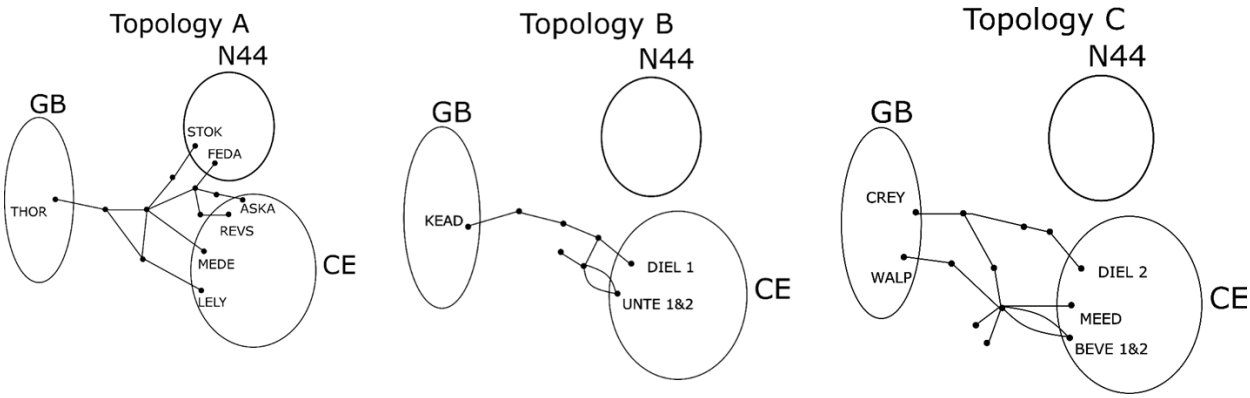

Figure 5-18 - Illustration of multi-terminal offshore grid topologies.

The three topologies are based on the bipolar configuration and exhibit minimal meshing. Topology A consists of 14 (7 offshore) nodes and interconnects all three onshore systems. Topologies B and C interconnect only the GB and CE systems and consist of 9 (5 offshore) and 14 (8 offshore) nodes, respectively.

Three operating points have been considered for the security analysis depending on the available wind farm (WF) production:

- High wind (HW): the WF production is set to 100%
- Medium wind (MW): the WF production is set to 50%
- Low wind (LW): the WF production is set to 20%. However, this scenario would result in very low utilization of the MOG, which is unrealistic. Hence, this scenario also assumes maximum power exchange between the three AC systems.

5.3.3.1.1 CALCULATION OF NORMAL OPERATING CONDITIONS

The first step is to calculate the normal operating conditions for each scenario. For this case, no sophisticated control of the terminals is required. One onshore terminal is selected as the slack bus (i.e. constant DC voltage). The rest are set to constant power mode depending on the percentage of the wind power production. For the LW scenario, the power of the VSCs connected to the GB and N44 system is set to its maximum value. One part of this power is provided by the WFs and the rest (if any) by the VSCs connected to the CE system.

5.3.3.1.2 N-1 SECURITY ANALYSIS

The second step investigates the security of the aforementioned topologies against N-1 contingencies. These contingencies include:

- Outage of both poles of a VSC
- Outage of both poles of a branch/cable

It is noted that the loss of both poles corresponds to the worst-case scenario since the bipolar configuration allows asymmetric operation following the outage of single pole.

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 691714.

In several cases, VSCs are connected to the rest of the MTDC grid through a single branch. As a result, the outage of this branch would lead to isolation of the VSC. As a result, the isolated VSC has to compensate alone for an imbalance equal to its pre-disturbance power. In such cases, it is expected that protection systems (e.g. surge arresters) would take action to prevent extreme DC voltage at the bus of the isolated VSC, and possibly keep it in operation as a STATCOM. Therefore, these cases are not considered when tuning the DC voltage droop gains.

For this step it is necessary to model appropriately the post-disturbance behaviour of the VSCs in response to DC voltage changes. Although several control strategies have been proposed to this purpose, the droop control is considered the most likely candidate and has been adopted in this work.

Therefore, all VSCs are equipped with the droop characteristic shown in Figure 5-19, where P, V the VSC power and DC voltage, respectively, P^{set}, V^{set} the corresponding power and DC voltage setpoints, and K_V the droop gain parameter. If the VSC reaches its maximum or minimum power, P^{max} or P^{min}, respectively, it cannot further regulate the DC voltage and switches under constant power mode.

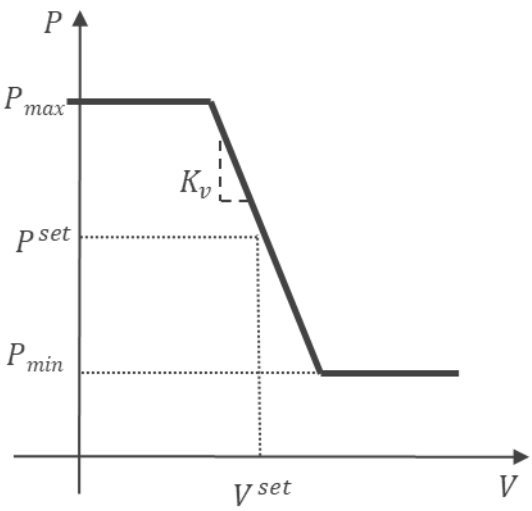

Figure 5-19 - P-IV droop characteristic of VSCs.

Increasing the value of the droop gain leads to tighter DC voltage control. In the following, all VSCs are equipped with DC voltage control with the same value of K_v. However, depending on the type of VSC (onshore or offshore) the regulating capability (i.e. the values of P^{min} and P^{max}) of the VSC may vary. Specifically:

- Onshore VSCs can regulate their DC voltage in the whole range defined by their rating, i.e. $-P^{min} = P^{max} = P^{nom}$
- In order to maximise the wind harvesting, the offshore VSCs inject to the MTDC grid the maximum power captured by the wind. Therefore, the WTs do not have any reserve and it is not possible to increase their production for long periods. However, in case of DC overvoltage it is possible to quickly curtail some of the WF power and support the DC voltage. As a result, the offshore VSCs can regulate downwards their active power, but not upwards. In addition, the WTs cannot absorb active power. The above are translated to $P^{max} = P^{set}$ and $P^{min} = 0$.

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5.3.3.1.3 DEALING WITH POST-CONTINGENCY DC VOLTAGE VIOLATIONS

The next step consists of tuning the DC voltage droop gain to prevent DC voltage violations. As already discussed the same value K_V has been assumed for all VSCs, for simplicity. Starting from a low value (e.g. $K_V = 1$ MW/kV), this value is gradually increased until all post-contingency DC voltage violations are between limits (i.e. $\pm 10\%$).

5.3.3.1.4 DEALING WITH POST-CONTINGENCY BRANCH OVERLOADS

The previous step results in a secure MTDC grid configuration as far as the DC voltage constraints are concerned. However, branch overloads have not yet been addressed. This is the subject of this step.

To ensure correct operation of the MTDC grid, some kind of coordinated control that receives information from the MTDC grid (e.g. voltage and branch current measurements) and sends back corrective actions is needed. In contrast to DC voltage violations (for which a secondary control is not fast enough to correct), branch overloads can be tolerated for a short time. This depends on several factors, such as the magnitude of the overload, the specifications of the cables, the pre-contingency loading level, etc. Based on this, here it is assumed that small overloads (e.g. 110% of the nominal cable rating) can be reliably corrected by the secondary control redispatching the VSCs.

5.3.3.2 DETERMINE REPRESENTATIVE WIND PRODUCTION PATTERNS

A transmission grid must be designed accordingly to a set of pre-defined operating conditions. The evacuation of the wind energy at full wind production has been used as reference case. For the Business-as-usual approach, this is the only relevant case. However, for meshed grids, it is not so trivial to define a set of operation conditions to be considered. In this Section, a method based on principal component analysis is illustrated in order to determine wind production patterns in the North Seas.

5.3.3.2.1 THEORETICAL BACKGROUND

Principal Component Analysis (PCA) is an unsupervised machine-learning algorithm allowing to reduce the number of dimensions required to describe a dataset while retaining as much of the original information as possible. The method seeks to determine so-called principal components which can be described as axes, linear combinations of original dimensions. These axes should cover as much variation contained in the original dataset as possible. After applying the method, each point in the dataset will be described by a coordinate of principal components determined by the user instead of the original dimensions.

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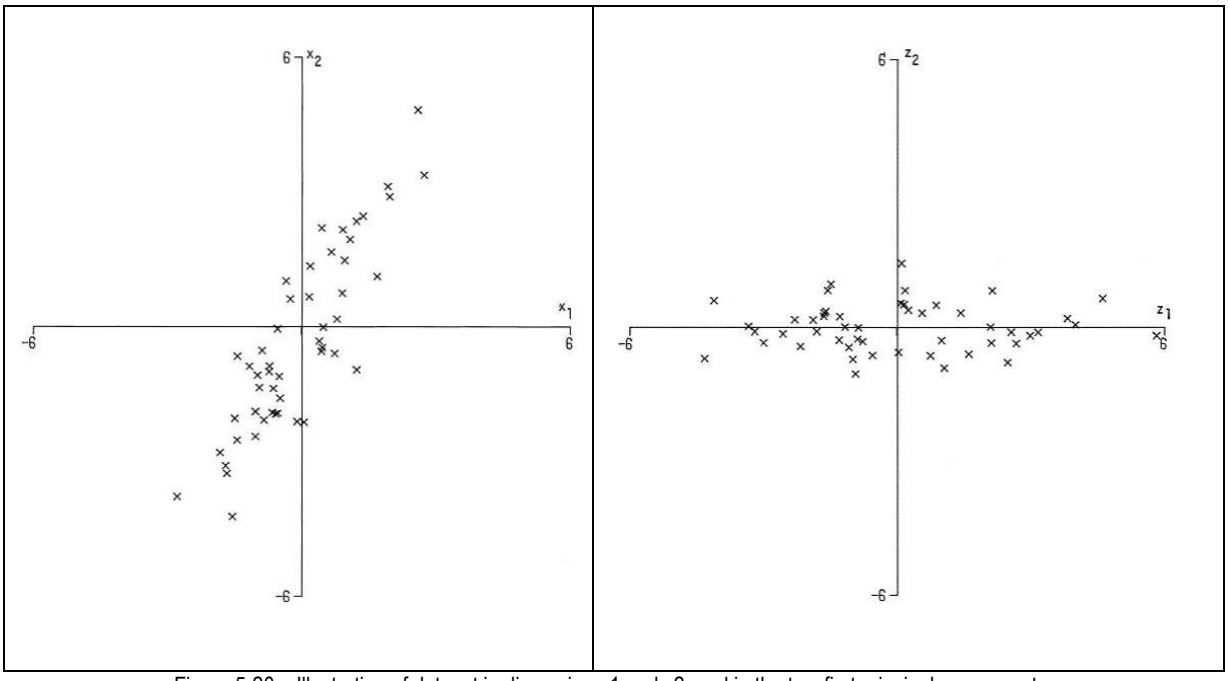

Figure 5-20 – Illustration of dataset in dimension x1 and x2, and in the two first principal components.

Figure 5-20 shows a set of 50 observations in two dimensions – x1 and x2. The PCA algorithm will successively go through the following steps:

1. Standardization

- Prior to any manipulation, the dataset will be normalised:
- $X_{i,new} = \frac{X_{i,old} - avg}{std}$

2. Covariance matrix

- The covariance matrix, which determines how initial variables are correlated with respect to one another, is then computed
- $\begin{bmatrix} Cov\ (x_1, x_1) & Cov\ (x_2, x_1) \\ Cov(x_1, x_2) & Cov\ (x_2, x_2) \end{bmatrix}$

3. Eigenvalues and Eigenvectors

- The eigenvectors and associated eigenvalues of the covariance are the computed
    - Eigenvectors, which are linear combination of original variables, are directions associated to the principal components
    - Eigenvalues associated indicate how much of the variance of the original dataset is captured by the principal components in question.

$$PC1 = \alpha_1 x_1 + \alpha_2 x_2\ with\ \lambda_1$$
$$PC2 = \alpha_3 x_1 + \alpha_4 x_2\ with\ \lambda_2$$

4. Dataset projection in principal components

- Now that principal components are known, the original dataset can be projected in these new components. It can be seen in Figure 5-20 that principal component 1 (PC1) captures most of the variance of the original dataset. Two PC are always uncorrelated, namely perpendicular.

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5.3.3.2.2 MOTIVATION

Finding correlations between the productions (or wind speed) at several locations would allow to determine potential recurrent production patterns and therefore allow to determine cases for verifying the topological design. Reducing the number of dimensions of the dataset would considerably ease interpretation and allow to identify these patterns. Moreover, dimension reduction should enable easier data cluster and scenario selection amongst the database. In summary, the objectives of PCA are

- Reduce dimensionality
- Ease data representation
- Find correlations in the dataset

5.3.3.2.3 PCA COMPUTATION

PCA was applied to a dataset composed of hourly wind speed (or wind production) at 53 different locations in the North Sea. The first step consists in determining how many dimensions are necessary to capture a significant amount of the variance of the original dataset. Figure 5-21 shows the evolution of the percentage of variance captured by component. Some observations can be drawn:

- The two first components allow to capture almost 70 % of the variance
- Higher rank components tend asymptotically from 7 down to 0%

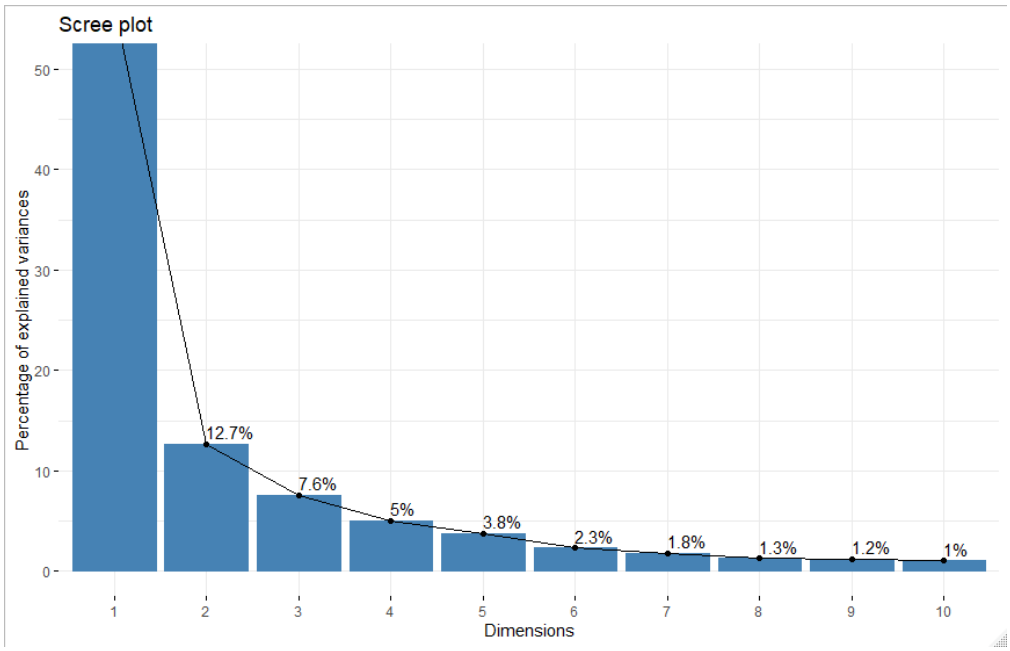

Figure 5-21 - Percentage of variance captured per principal component.

One of the drawbacks of PCA is that it is more difficult to interpret the results in non-physical dimensions. A correlation circle is a very useful tool to visualise the PCA components and evaluate the similarities in the two first PCAs between the original variables. In Figure 5-22, all original variables are plotted in principal components coordinates and coloured by countries for the sake of interpretation. It must be noted that the distance between the point and the centre is an indicator of how well the original variable contributes to the two principal components. The following observations can be made:

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- All points show a positive PC1 value. This means all geographic regions are positively correlated, and can be translated as “in most cases, when the wind is high (low) in a region, so it is in all other regions”. PC1 axis can be understood as an overall wind production axis. Individuals with a low (high) PC1 value have low (high) overall wind production.
- All points belonging to a same country in Figure 5-22 are close to one another, which means they are positively correlated. However, some small “internal clusters” are observed, such as in UK group. This observation translates into local wind effects which can be explained by the fact that wind production in the Dogger Bank area is not fully correlated with wind production closer to the UK shore.
- The wind speed observations in Ireland, Norway and France participate less to the main PCA. This is understandable due to the remote locations of these observations compared to the rest.
- Figure 5-23 shows the results of a clustering in a 3-dimensional space composed of the three first components. It can be observed that each cluster represents a geographical region in the North Sea.

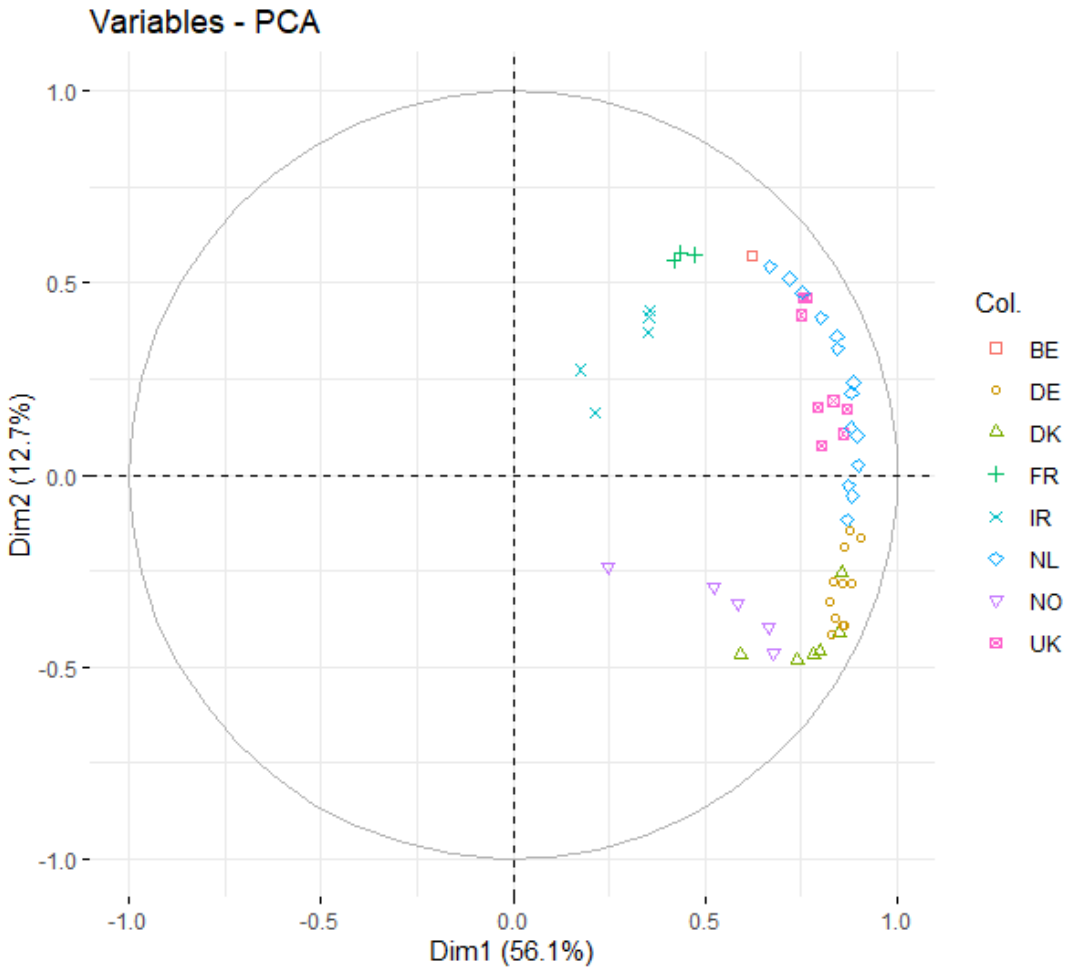

Figure 5-22 - Correlation circle (by country).

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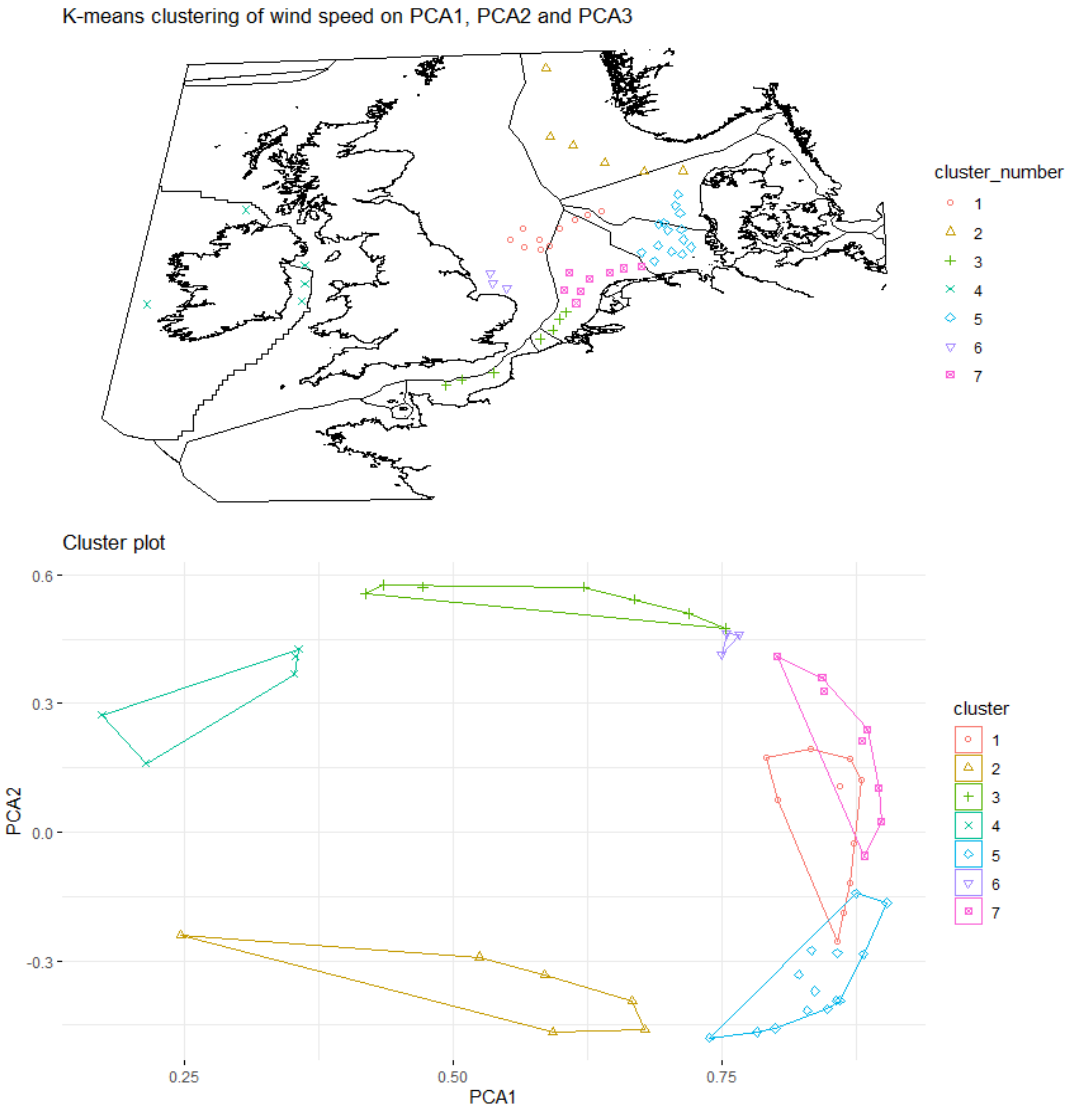

Figure 5-23 - Geographical locations of the sites.

In addition to being able to cluster the original dimensions which are correlated, the PCA technique allows to identify some patterns in the dataset. In order to illustrate the pattern for each of the three first components, the observations having the highest and lowest value for each of these components are shown in Figure 5-24.

From Figure 5-24, it can be observed that the first PCA captures the total wind production in the North Sea. It means that there are some hours of the year where the wind blows everywhere in the North Sea while at other times, the wind speed is low at almost all locations. Note that the difference is less clear for locations in Norway, this is consistent with Figure 5-23 which showed that locations in Norway participate less to the first PCA.

The extreme observations of the second PCA show a negative correlation between the wind production in the North-East (Norway, Denmark) and the South (France, Belgium, The Netherlands and some parts of the UK).

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The third PCA captures observations with low production in Belgium, The Netherlands and Germany combined with a negative correlation between the wind speed in the Dogger Bank area/Ireland/Norway and The Channel.

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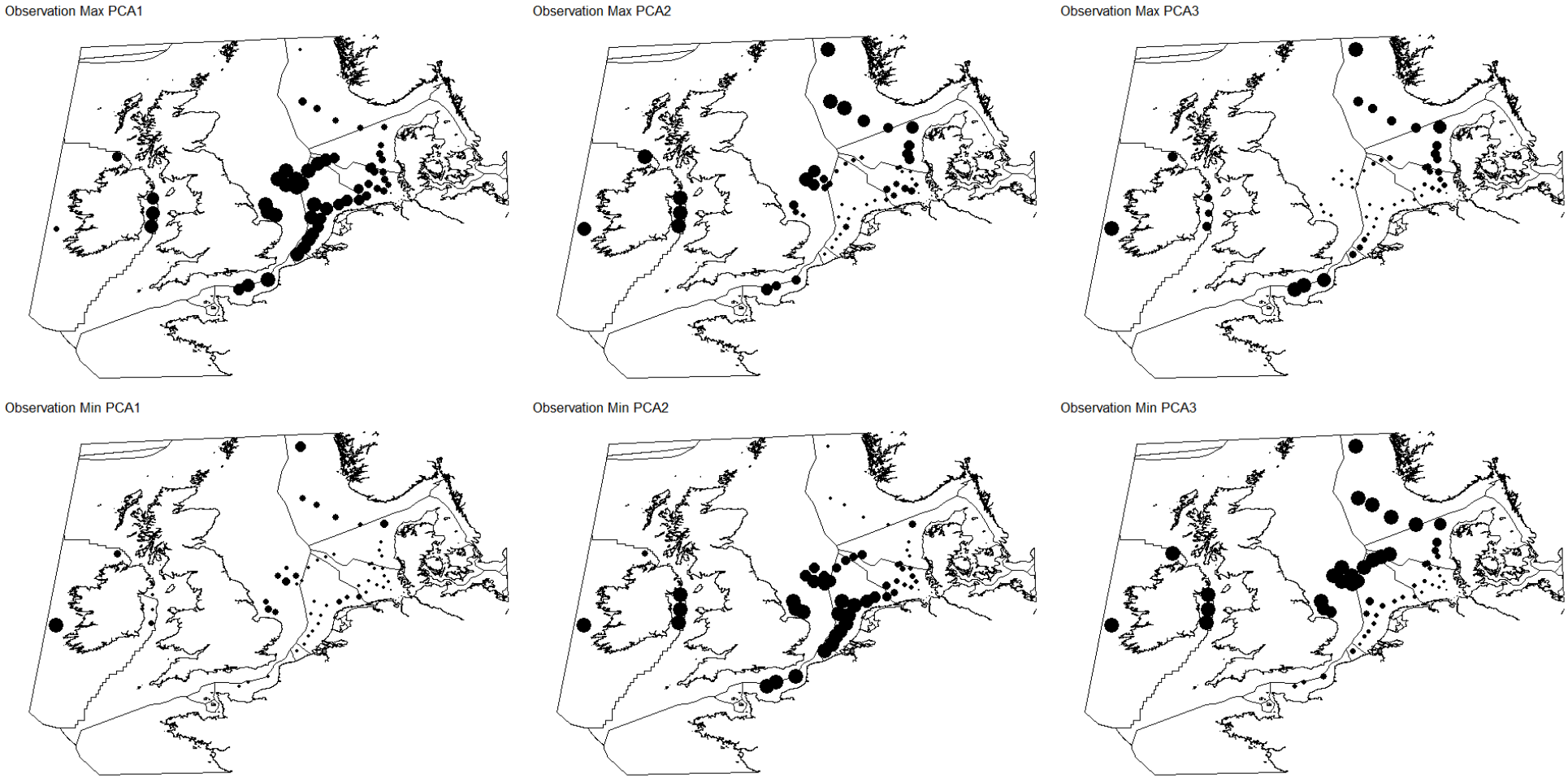

Figure 5-24 - Observations having the maximum and maximum of the PCA1 (left), PCA2 (center) and PCA3 (right).

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5.3.3.2.4 CONCLUSION

A PCA analysis, based on historical wind speed measurements, has shown to be useful in order to identify some wind production patterns. Three patterns could be identified and from the analysis, these patterns explain 75% of the variance of the dataset.

The main benefits of this analysis are that these patterns can be used:

- to verify more in details the design of the MOG in several operating conditions
- to assess the impact of the protection strategies in several operating conditions

5.4 RESULTS FOR THE HIGH WIND SCENARIO

The results will be presented successively for each of the four concepts. For each concept, the results of the whole optimisation process are first shown for each optimisation time step (i.e. 5-year interval). This illustrates the potential development of the offshore grid from 2025 to 2050. Then, the observations of the step 1 (OTEP) are described followed by the results of the optimisation of the interconnection. Next, a short Section on recommendations drawn from the security analysis takes place. Finally, a Section compares the different concepts.

5.4.1 BUSINESS-AS-USUAL APPROACH

5.4.1.1 TIME EVOLUTION OF THE TOPOLOGY

For the sake of clarity, the results are first illustrated for both optimisation steps. This represents a potential future topology in the North Sea for the BAU concept and the High wind scenario. The topologies are represented in Figure 5-25 to Figure 5-27. Note that these figures represent also existing/planned interconnectors as well as existing/planned windfarms.

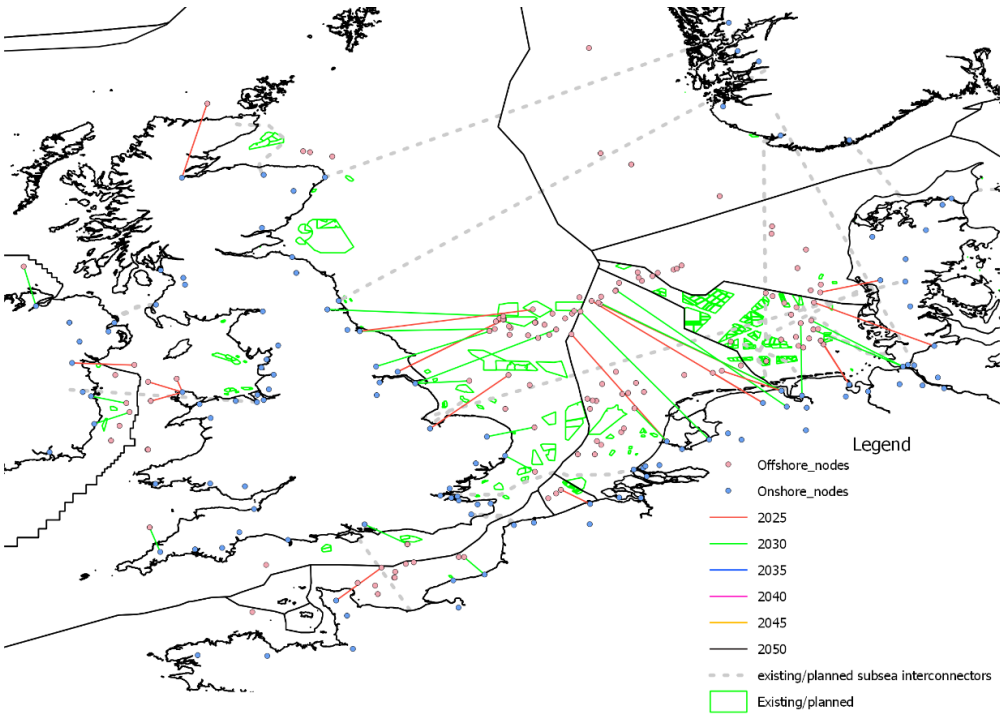


Figure 5-25 - High wind scenario, BAU concept, topology in 2030.

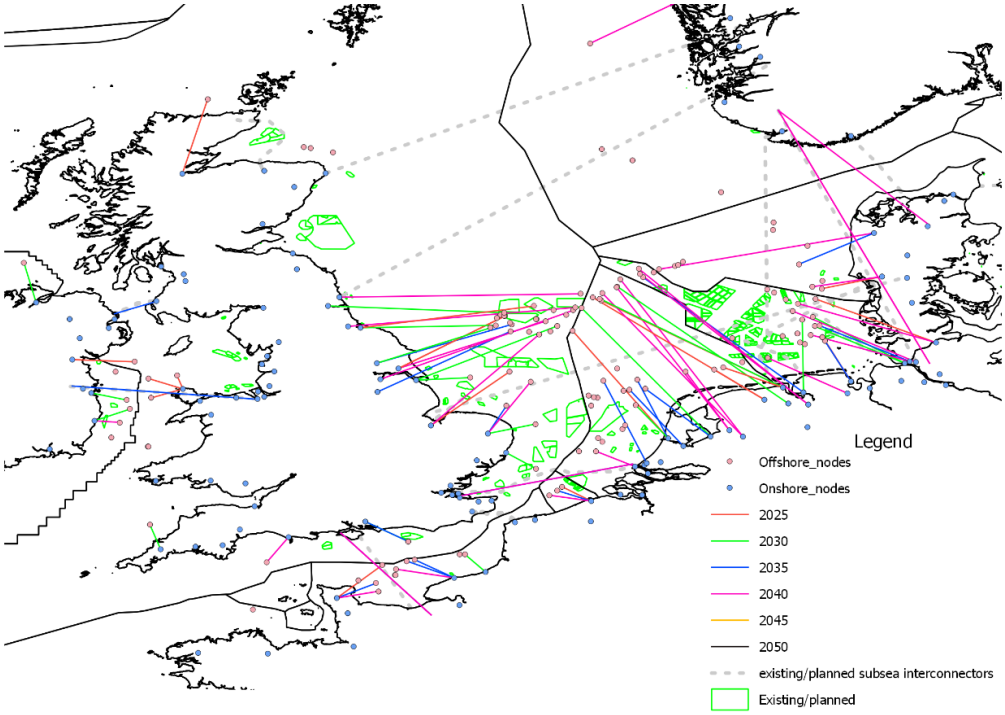


Figure 5-26 - High wind scenario, BAU concept, topology in 2040.

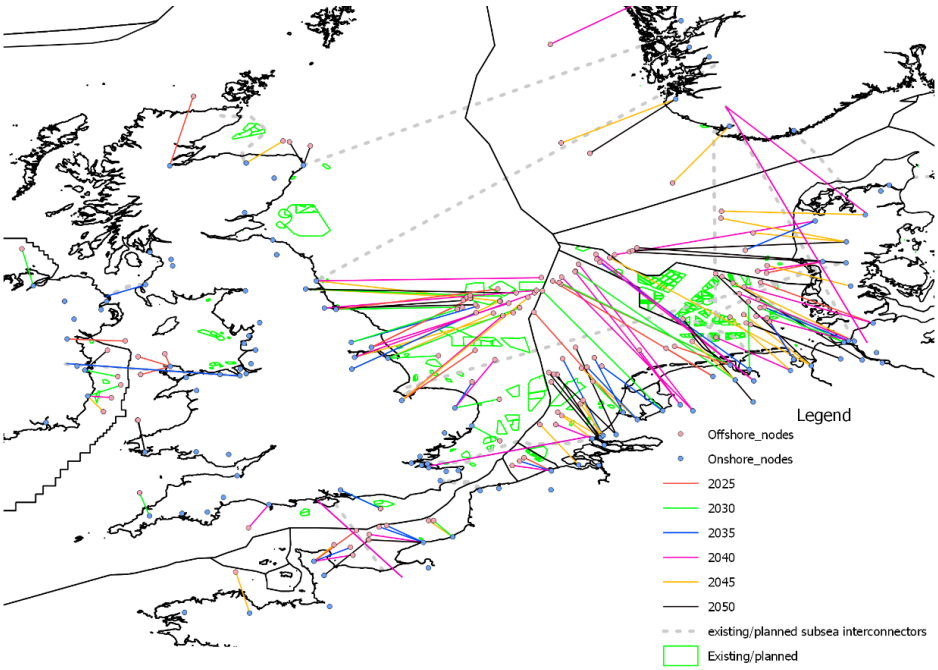


Figure 5-27 - High wind scenario, BAU concept, topology in 2050.

5.4.1.2 STEP 1 - OTEP

The main observations of the OTEP step for the BAU concept High wind scenario are illustrated here below. It is worth reminding that this step aimed at having a grid able to evacuate the whole offshore wind production to its respective country. Therefore, the results can easily be deducted from the previous figures by removing the interconnection lines.

Onshore connections

In the BAU case, the OTEP step tends to connect the offshore nodes to the closest onshore points. Because of onshore hosting capacity constraint (maximum 4 GW per onshore connection), many onshore candidates are needed.

Anticipatory investment (temporary oversizing of cables)

The cable capacities are optimised for a 10-year horizon. Therefore, some cables are oversized for some target years in order to accommodate future offshore wind production.

5.4.1.3 STEP 2 - OPTIMISATION OF INTERCONNECTIONS

In the BAU approach, the candidate interconnectors are only from shore to shore. The optimisation leads to the results shown in Table 5-9. The values in the table present the already existing/interconnectors and the additional investment required in the developed scenarios.

Table 5-9 - Transmission capacity expansion in the BAU concept High wind scenario (in GW). Numbers in black are the existing/planned interconnections, numbers in red are the point-to-point expansions.

INTERFACE	2020	2025	2030	2035	2040	2045	2050
BE-GB	1	1	1	1	1	1	1
DE-DKe	1	1	1	1	1+2.2	1+2.2	1+2.2
DE-GB	1.4	1.4	1.4	1.4	1.4	1.4	1.4
DE-NOs	1.4	1.4	1.4	1.4	1.4+1.6	1.4+2.8	1.4+2.8
DKw-GB	0	1.4	1.4	1.4	1.4	1.4	1.4
DKw-NL	0.7	0.7	0.7	0.7	0.7	0.7	0.7
DKw-NOs	1.6	1.6	1.6	1.6+1.2	1.6+1.5	1.6+1.8	1.6+1.8
FR-GB	4	6.8	6.8	6.8+2.2	6.8+5.7	6.8+5.7	6.8+5.7
GB-IE	0.5	0.5	0.5	0.5	0.5+1.4	0.5+1.8	0.5+1.8
GB-NI	0.5	0.5	0.5	0.5+1.2	0.5+1.2	0.5+1.2	0.5+1.2
GB-NL	1	1	1	1+0.8	1+3.7	1+3.7	1+3.7
GB-NO	0	2.8	2.8	2.8	2.8	2.8	2.8

The following observations are made on the BAU model. These observations result from an optimisation trying to reduce the overall operation costs by investing in the least-cost candidate transmission lines. In the BAU model, the candidates for transmission expansion are direct connections from one country to another. There is no transmission candidate from an offshore point.

5.4.1.3.1 GERMANY-NORWAY AXIS

Germany goes through a period of high short-run marginal cost (SRMC) due to the phase-out of nuclear and of coal from 2030 to 2035. Cheaper electricity is available from France or from Norway, which has plenty of flexible hydro generation. The optimised transmission investment gives around 3 GW additional connecting Germany to Norway in 2040.

5.4.1.3.2 GERMANY-EASTERN DENMARK AXIS

Intense electricity exchanges take place between the eastern part of Denmark and Germany from 2020 to 2050. The currently planned interconnection is congested more than 70% of the year during these 3 decades.

The investment cost in a transmission from Germany to Eastern Denmark is low enough to reinforce the existing 1 GW connection by an additional 2 GW. This investment is justified thanks to the reduction the overall operation costs that it triggers.

5.4.1.3.3 FRANCE-GREAT BRITAIN AXIS

Exports of electricity from France to Great Britain rely in the BAU model on the country-to-country interconnection. Even by considering the already planned 6.8 GW interconnection capacity between these two countries, this interconnection is congested a significant amount of time. Therefore, an investment in the candidate transmission line between these two countries is justified to minimise their difference of SRMC costs. The total transfer capacity built amounts to more than 12 GW in 2040.

5.4.1.3.4 THE NETHERLANDS-GREAT BRITAIN AXIS

Energy exchange between these two major actors in the offshore wind development in the North Sea triggers the investment of almost 4 additional GW of interconnection by 2040.

5.4.1.3.5 GREAT BRITAIN -NORTHERN IRELAND AND GREAT BRITAIN -IRELAND AXES

The interconnection candidates between Great Britain one side, Ireland and Northern Ireland on the other side trigger an investment in this interconnection by the optimisation model. A 1.2 GW investment is performed in 2035 between Great Britain and Northern Ireland. Between Great Britain and Ireland, the investment is higher and amounts to 1.8 GW in 2050.

5.4.1.3.6 CONGESTIONS ON THE COUNTRY-TO-COUNTRY INTERCONNECTIONS OF THE TYNDP

Several interconnections of the TYNDP model congest during a significant share of the years from 2020 to 2050. Notably, the interconnections from Denmark-East to Denmark-West, from Denmark-West to Sweden, from France to Belgium, France to Germany, Belgium to the UK and to Germany and from 2035 from the Netherlands to Germany are congested during more than half of the year.

Major hydropower exports also congest the transmission lines from Norway to the Southern region of Norway (where the load is located) and to Sweden. The absence of candidate lines prevents further operational costs reduction in this region.

5.4.1.4 STEP 3 - SECURITY ANALYSIS

In the BAU case, the N-1 security analysis leads to loss of power infeed. By design, there are no cases where the consequence of fault spreads to the rest of the MOG.

5.4.2 NATIONAL DISTRIBUTED HUBS APPROACH

5.4.2.1 TIME EVOLUTION OF THE TOPOLOGY

In this Section, the results are illustrated for both optimisation steps. This represents a potential future topology in the North Sea for the NAT concept and the High wind scenario. The topologies are represented from Figure 5-28 to Figure 5-30. Note that these figures represent also existing/planned interconnectors as well as existing/planned windfarms. It can be observed that the network is composed of radial and multi-terminal connections, and becomes increasingly meshed after 2040. This meshing results mainly from the second optimisation, which will be further described in Section 5.4.2.3. It is worth keeping in mind that a clustering step had been performed for this scenario in order to decrease the mathematical complexity (as mentioned in Section 5.3.1.1). Therefore; one offshore node seen in the figures may represent several offshore platforms close to each other. Similarly, the lines representing HVDC subsea cables could represent multiple cables in parallel.

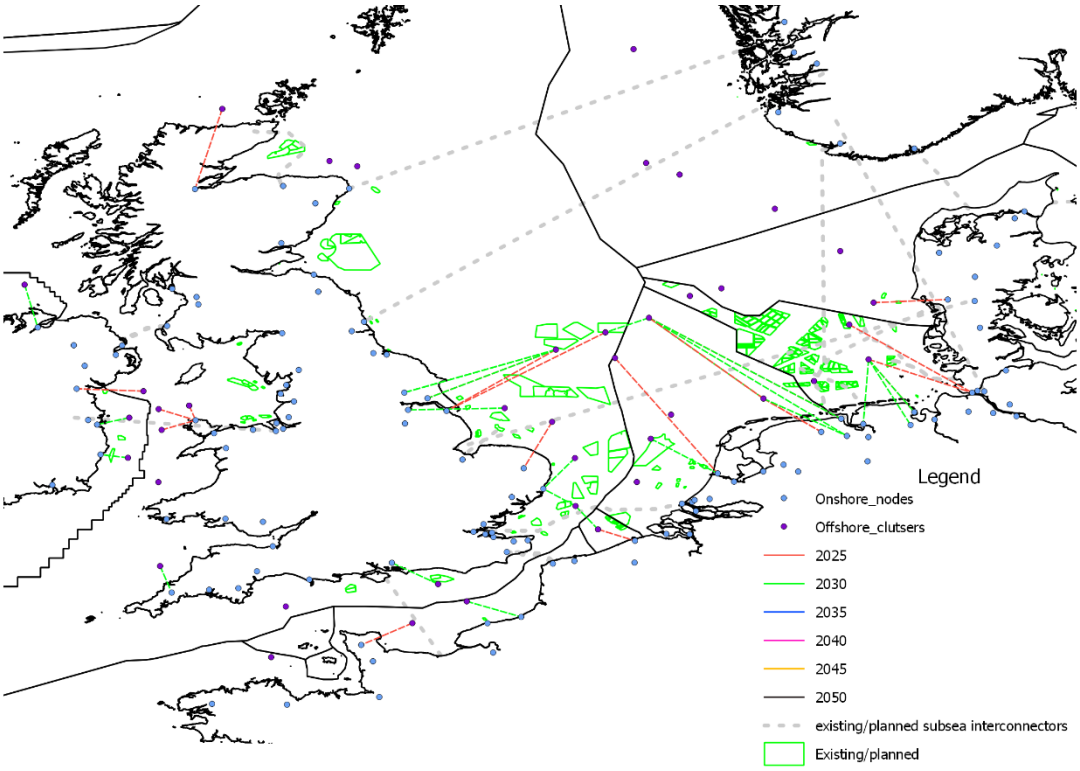


Figure 5-28 - High wind scenario, NAT concept, topology in 2030.

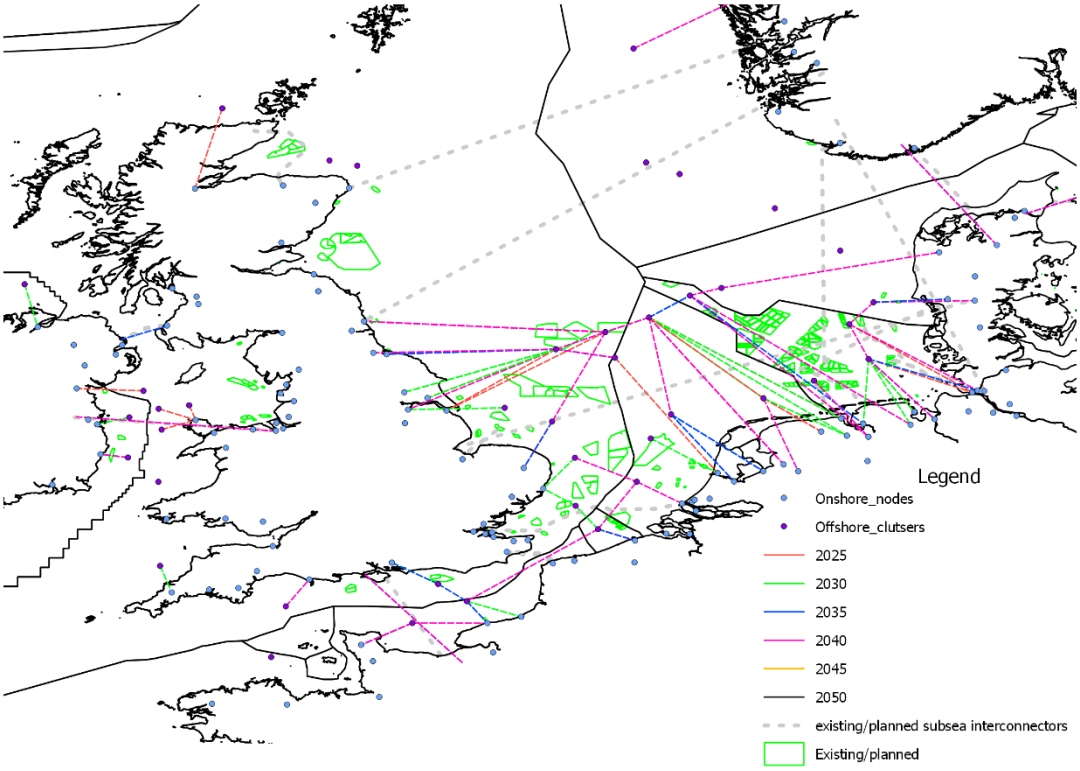


Figure 5-29 - High wind scenario, NAT concept, topology in 2040.

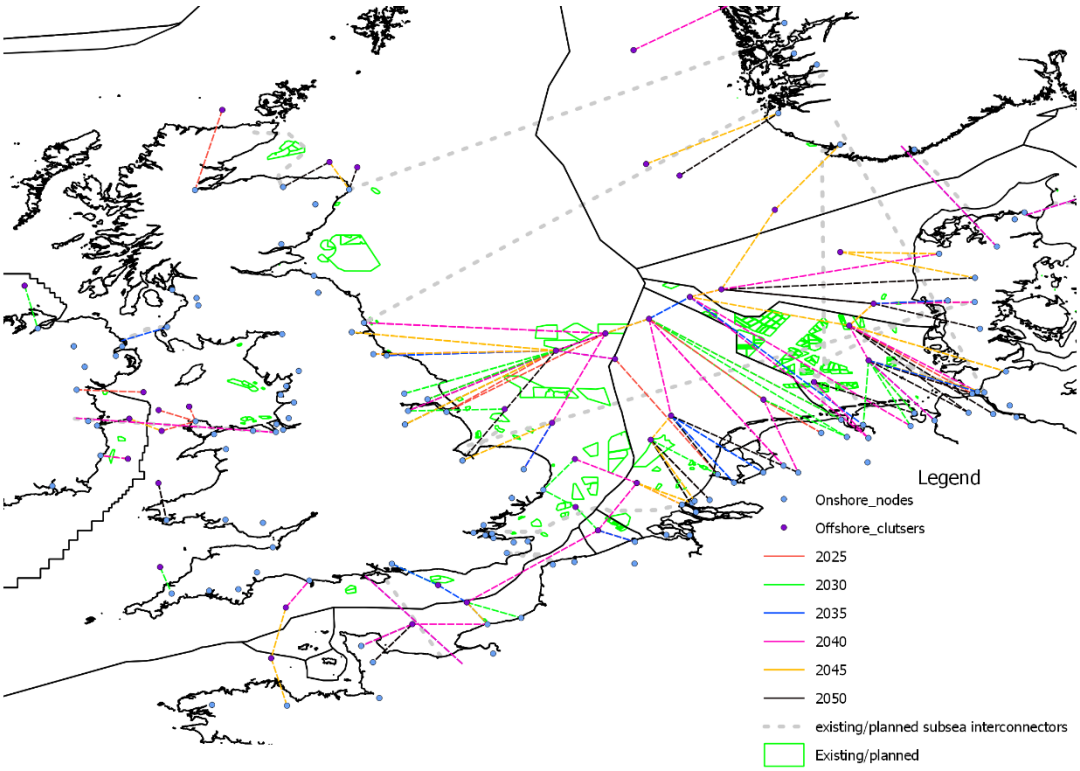


Figure 5-30 - High wind scenario, NAT concept, topology in 2050.

5.4.2.2 STEP 1 - OTEP

The results of the OTEP can be observed from the previous figure. In the NAT concept, it is not allowed in step 1 to interconnect nodes from different countries. Therefore; all connections within the same country comes from

step 1 while the cross-border connections (onshore and offshore) come from step 2. As a reminder, this step is performed to find the least cost topology able to evacuate the offshore wind energy to shore. The main observations of this step for the NAT case are:

Creation of multi-terminal DC connections

In the NAT case, the OTEP step tends to create multi-terminal DC grid in order to optimise the use of cable rating and therefore to minimise the cable length. The multi-terminal DC grids can be found at some specific locations and are influenced by the locations of the wind farms and by their expected expansion. Therefore, a coordination planning of the transmission investments and OWF development is required.

Anticipatory investments and modularity

Similarly to the BAU concept, the NAT concept requires anticipatory investments. Therefore, cables might be oversized for some target years or the multi-terminal connections can be created in order to facilitate future wind generation. The multi-terminal connections might also create more connection options for future wind farms which bring modularity in the development of the MOG.

Onshore connections

Because of onshore hosting capacity constraint (assumption of maximum 4 GW per onshore connection), many onshore candidates are needed. However, the difference with the BAU concept is that in some cases, a multi-terminal connection is used to reach an onshore point with sufficient hosting capacity.

5.4.2.3 STEP 2 - OPTIMISATION OF INTERCONNECTIONS

Table 5-10 lists the investments in transmission capacity expansion on the candidate interconnectors. The candidates without investment are removed from the table. The values in the table present the already existing/interconnectors and the additional investment required in the NAT scenario.

Table 5-10 - Transmission capacity expansion in the NAT concept High wind scenario (in GW). Numbers in black are the existing/planned interconnections, numbers in red are the point-to-point expansions and in blue the expansions via the MOG.

INTERFACE	2020	2025	2030	2035	2040	2045	2050
BE-FR					1.2	1.2	1.2
BE-GB	1	1	1+0.8	1+0.8	1+0.8	1+1.4	1+1.4
BE-NL					0.7	0.7	0.7
DE-DKe	1	1	1	1+0.7	1+0.7	1+0.7	1+0.7
DE-DKw				0.5	4.9	7.2	7.4
DE-GB	1.4	1.4	1.4	1.4	1.4	1.4	1.4
DE-NL				0.8	3.2	3.2	3.2
DE-NOs	1.4	1.4	1.4	1.4	1.4	1.4	1.4

INTERFACE	2020	2025	2030	2035	2040	2045	2050
DKw-NOs				1.1	2.9	3.4+1.1	3.4+1.1
FR-GB	4	6.8	6.8+0.5	6.8+0.4+1	6.8+3.3+1	6.8+3.3+1.4	6.8+3.3+1.4
GB-IE	0.5	0.5	0.5	0.5+0.6+0.9	0.5+0.6+1.4	0.5+0.6+1.4	0.5+0.6+2.2
GB-NI	0.5	0.5	0.5	0.5	0.5+1.3	0.5+1.3	0.5+1.3
GB-NL	1	1	1+1.2	1+1.2	1+3	1+4.8	1+6.3
GB-NOs	0	2.8	2.8	2.8	2.8	2.8	2.8

5.4.2.3.1 GERMANY-NORWAY AXIS

Instead of reinforcing the point-to-point transmission line from Germany to Norway, the optimisation model invests in the development of the offshore candidate lines going from Germany to Denmark West, Denmark West to Norway, and on the point-to-point Denmark West to Norway. In more details, Germany becomes better interconnected with Denmark through the significant development of the line DK_OFF25-DE_OFF15 and of the line DK_OFF27-DE_OFF16. The interconnection from Denmark to Norway is implemented by reinforcing of the country-to-country connection line in 2040 and by the development of the candidate line DK_OFF25-NO_OFF38 in 2045. Figure 5-31 illustrates the onshore and offshore lines used for these energy transfers from Norway to Germany.

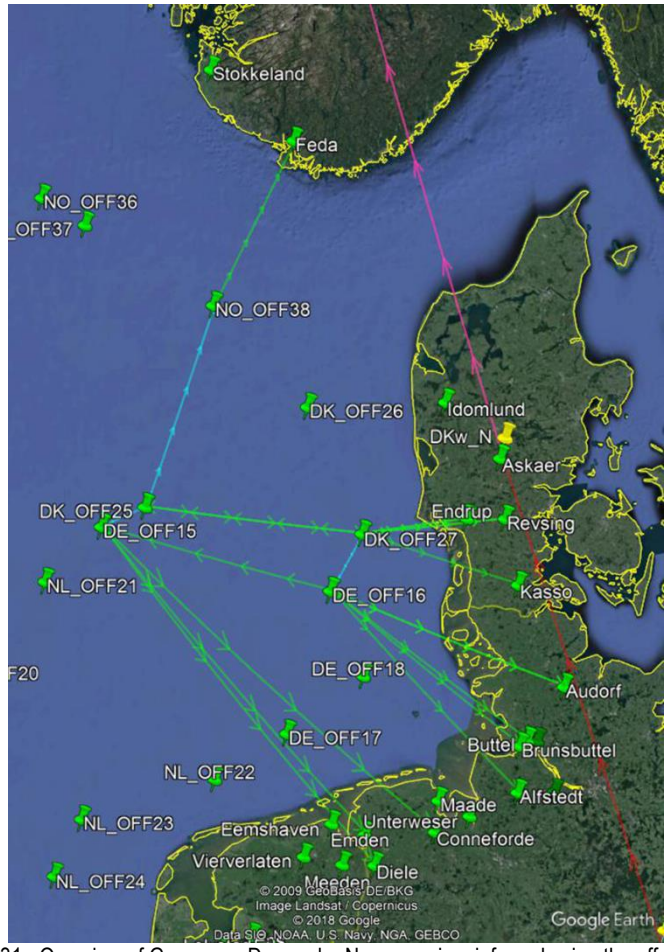


Figure 5-31 - Overview of Germany - Denmark - Norway axis reinforced using the offshore grid.

5.4.2.3.2 GERMANY-EASTERN DENMARK AXIS

The country-to-country candidate transmission line is extended in 2040 by 0.7 GW in the NAT case which is much lower than the BAU case.

5.4.2.3.3 FRANCE-GREAT BRITAIN AXIS

In the NAT model, the investment in the country-to-country interconnection from France to the Great Britain is significantly reduced by investment in the offshore interconnection UK_OFF09-FR_OFF28 and/or UK_OFF10-FR_OFF29 as illustrated in Figure 5-32.

The total transmission capacity developed between France and the UK in the NAT model is slightly lower than in the BAU concept but at a much lower cost because it makes use of multi-terminal connections.

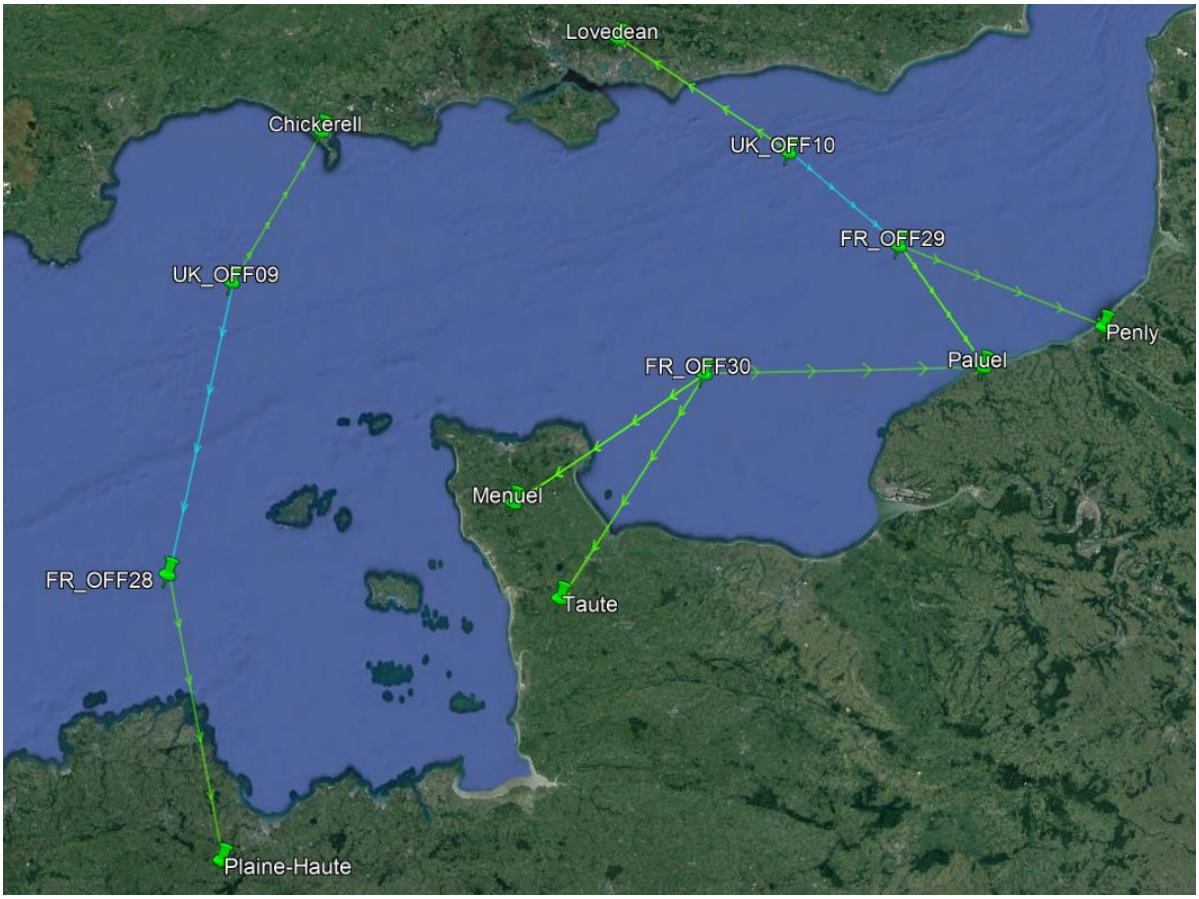


Figure 5-32 - Expansion in The Channel.

5.4.2.3.4 THE NETHERLANDS-GREAT BRITAIN AXIS

The additional interconnections between The Netherlands and Great Britain are exclusively in the MOG on three corridors. The first corridor, illustrated in Figure 5-33, could potentially lead to a connection to Belgium and to France. Note that the simulations assume HVDC grid only but the reality could be a combination between AC and DC design. The two other corridors make use of short distances between Dutch and British wind farms and can be seen in Figure 5-35. The amount of interconnections between Dutch and British windfarms is increased at every simulation steps after 2035 to reach more than 6 GW in 2050.

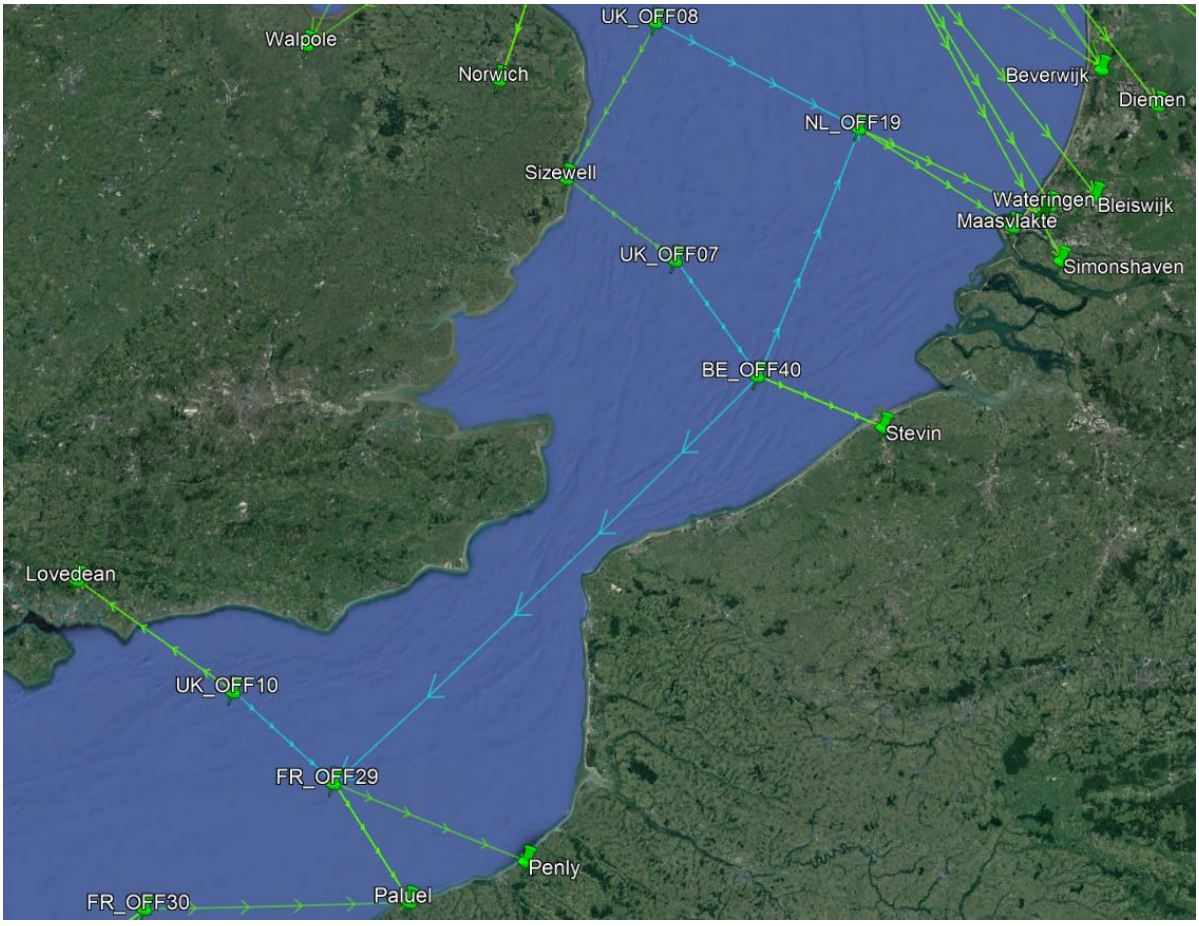


Figure 5-33 - Netherlands-Great Britain-Belgium axis (+ potential connection to France).

5.4.2.3.5 GREAT BRITAIN-NORTHERN IRELAND AND GREAT BRITAIN-IRELAND AXES

The offshore candidate transmission line IR_OFF33-UK_OFF11 is marginally developed while the hybrid connection IR_OFF33 to Wylfa is developed by more than 1 GW. The direct country-to-country interconnection line is also reinforced by 0.6 GW. Refer to Figure 5-34.

Figure 5-34 - MOG expansion candidates in the Irish Sea.

5.4.2.3.6 CONGESTIONS ON THE COUNTRY-TO-COUNTRY INTERCONNECTIONS OF THE TYNDP

The congestions of the onshore connections of the BAU model are partly solved by the opportunities to develop the offshore interconnections between the Netherlands and Great Britain: NL_OFF21-UK_OFF03 is developed by 3.2 GW in 2040 to reach 6 GW in 2050, to a lesser extend UK_OFF04_NL_OFF20 is developed by almost 1 GW

and the interconnection NL_OFF21-DE_OFF15 is developed by 3 GW to allow the formation of a backbone in the Dogger Bank. The energy exchanges between the Netherlands and Germany also benefits from the MOG. In addition, the transfer capacity between France and Belgium could be increased by using the MOG.

Figure 5-35 illustrates the expansion selected amongst the candidate transmission lines for an energy transfer backbone across the North Sea: 6.3 GW of transmission capacity is developed in total between Great Britain and the Netherlands, 7.4 GW is developed between Germany and Denmark and 1 GW is developed between Denmark and Norway.

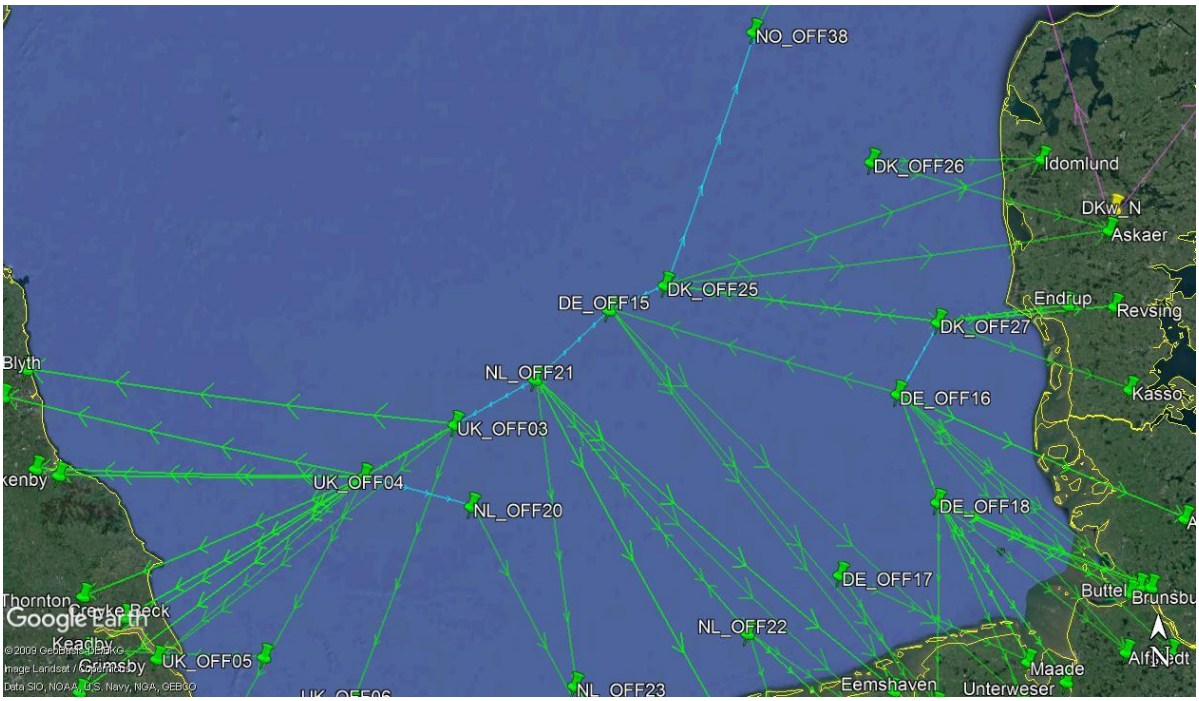


Figure 5-35 - Illustration of "backbone" through Dogger bank.

5.4.2.4 STEP 3 - SECURITY ANALYSIS

In the NAT case, load flow analyses in the healthy state (no outage) were performed for each target year at maximum wind production. No overload or overvoltage of equipment was observed.

In N-1, droop control is required to avoid over-voltages post-contingency. Special protection schemes are also needed to initiate fast control actions post-contingency to avoid overloads.

5.4.3 EUROPEAN CENTRALISED HUBS APPROACH

5.4.3.1 TIME EVOLUTION OF THE TOPOLOGY

In this Section, the results are illustrated for both optimisation steps. This represents a potential future topology in the North Sea for the HUB concept and the High wind scenario. Six artificial islands have been located in the North Sea and are assumed available from 2025. This is indeed a very optimistic assumption but is it worth keeping in mind that the main goal is to derive potential future topologies if the hub concept is followed, not to propose an exact planning timeline. The topologies are represented from Figure 5-36 to Figure 5-38. Note that these figures represent also existing/planned interconnectors as well as existing/planned windfarms. It can be observed that the wind farms close to each hub tend to connect first to the hub and then the hub is connected to shore or to another hub. It can also be observed that wind farms further from hubs are sometimes part of a multi-terminal configuration and therefore could benefit of a large DC cable from one hub to shore. It is important to

outline that the hubs have been located empirically in order to minimise the distance between wind farms and hubs. However, a proper optimisation algorithm was not used to decide the number and locations of the hubs.

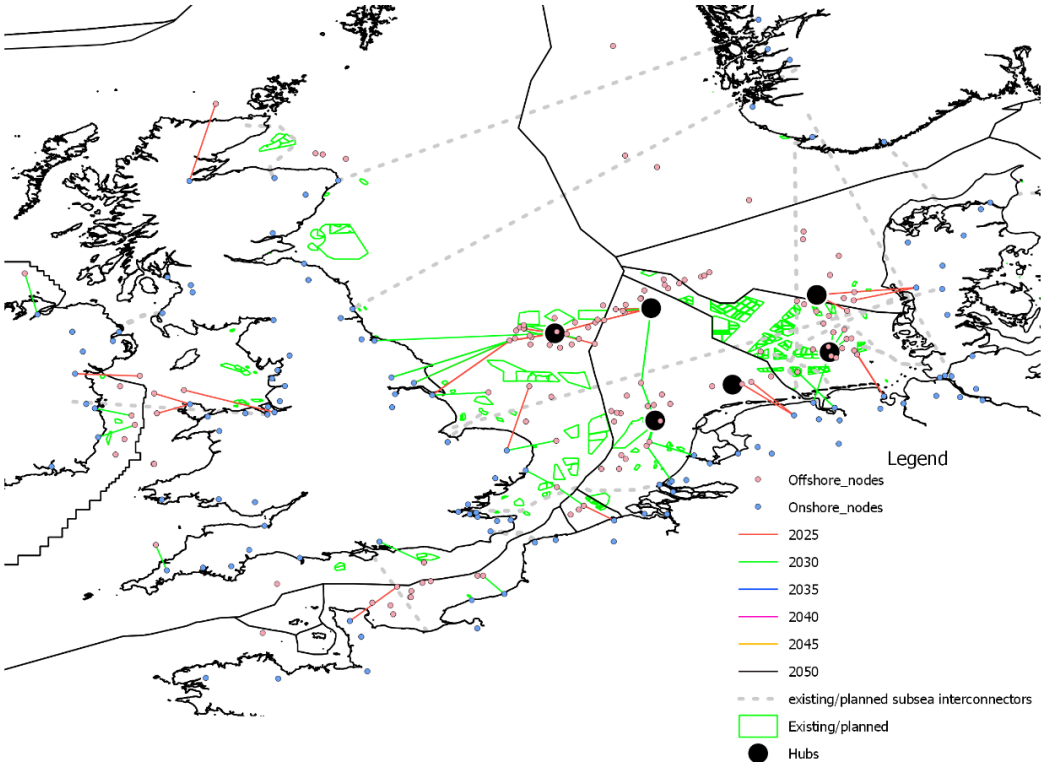


Figure 5-36 - High wind scenario, HUB concept, topology in 2030.

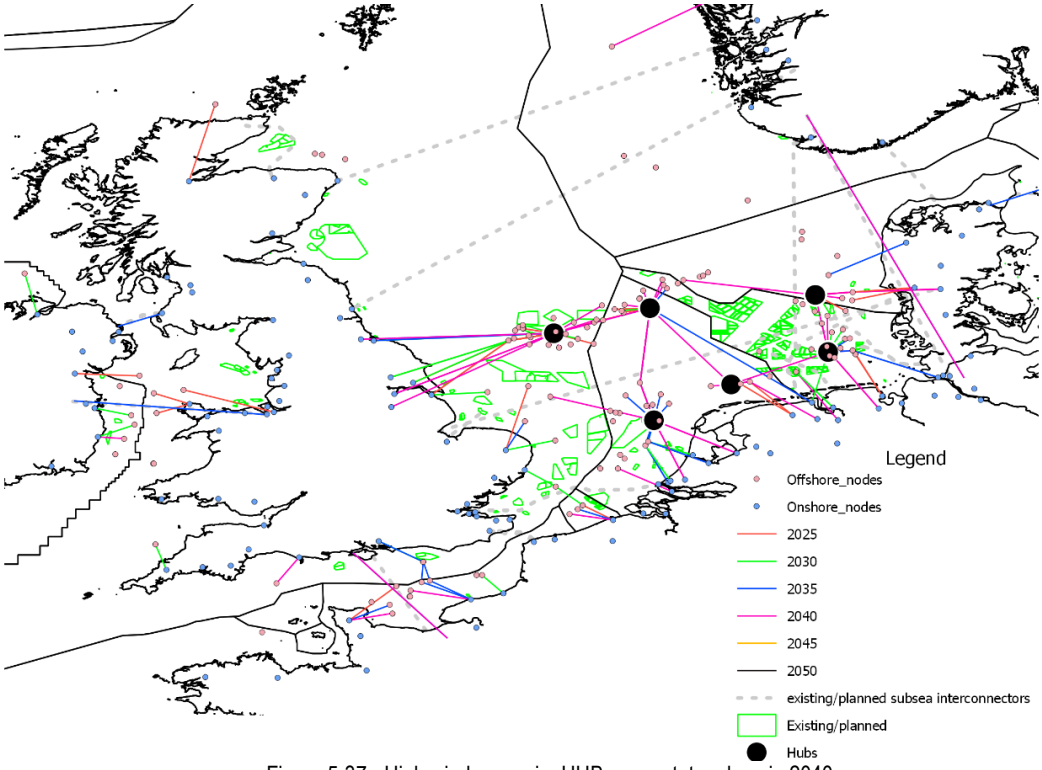


Figure 5-37 - High wind scenario, HUB concept, topology in 2040.

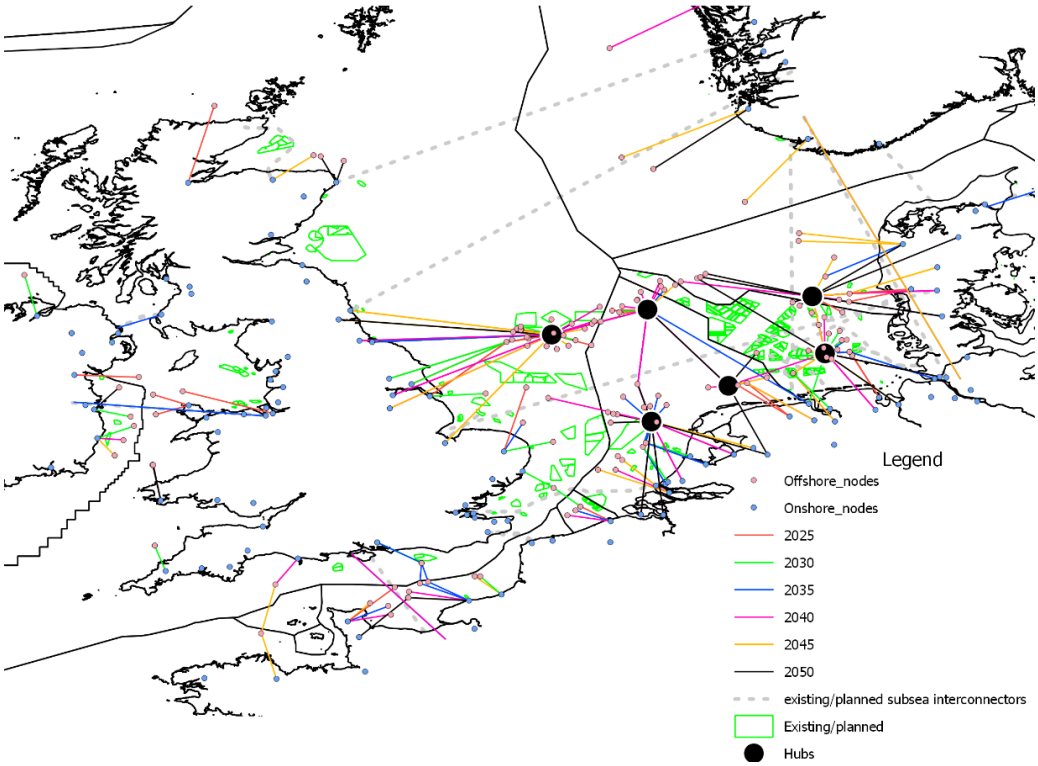


Figure 5-38 - High wind scenario, HUB concept, topology in 2050.

5.4.3.2 STEP 1 - OTEP

The main observations resulting from the OTEP step for the High wind scenario and HUB concept are the following:

AC-connection to hub

In the centralised-hub concept, six artificial islands are considered. The connections from an offshore node to the artificial islands can be much cheaper if the distance allows an AC connection. The cables from islands to islands and from islands to shore are only in DC. Therefore, the algorithm tends to connect wind farms to the closest island and then to optimise the number of DC cables from each island to shore.

DC connection to shore and between islands

The connections to shore and between islands are done only in DC. Because the wind production is aggregated to each island, most of the DC cables will have a high rating.

Multi-terminal DC connection

For windfarms located between shore and an island, it might be interesting to connect them using a multi-terminal DC connection between the island, the windfarm and the shore.

5.4.3.3 STEP 2 - OPTIMISATION OF INTERCONNECTIONS

Table 5-11 lists the investments in transmission capacity expansion on the candidate interconnectors. The table allows to make the distinction between already planned/existing interconnectors, expansions via the MOG and expansions via direct connections.

Table 5-11 - Transmission capacity expansion in the HUB concept High wind scenario (in GW). Numbers in black are the existing/planned interconnections, numbers in red are the point-to-point expansions and in blue the expansions via the MOG.

INTERFACE	2020	2025	2030	2035	2040	2045	2050
BE-GB	1	1	1+0.8	1+0.8	1+0.8	1+1.2	1+1.2
DE-DE_hub	0	0	4	4.8	4.8	4.8	4.8
DE-DKe	1	1	1	1	1+0.7	1+0.7	1+0.7
DE-GB	1.4	1.4	1.4	1.4	1.4	1.4	1.4
DE_hub-NL_hub					1	1	1
DE-NOs	1.4	1.4	1.4	1.4+1.3	1.4+3.6	1.4+5.6	1.4+5.6
DK_hub-DE_hub					1.1	2.7	2.7
DKw-GB	0	1.4	1.4	1.4	1.4	1.4	1.4
DKw-NL	0.7	0.7	0.7	0.7	0.7	0.7	0.7
DKw-NOs	1.6	1.6	1.6	1.6	1.6	1.6	1.6
FR-GB	4	6.8	6.8	6.8+0.3+1	6.8+4.3+1.4	6.8+4.3+1.4	6.8+4.3+1.4
GB-IE	0.5	0.5	0.5	0.5	0.5+1.4	0.5+1.8	0.5+1.8
GB-NI	0.5	0.5	0.5	0.5+1.2	0.5+1.2	0.5+1.2	0.5+1.2
GB-NL	1	1	1	1	1	1	1
GB_hub-NL_hub					2.9	3.2	3.6
GB-NO	0	2.8	2.8	2.8	2.8	2.8	2.8

The HUB model leaves the possibility of investing between the HUBs located in the North Seas to interconnect the countries. The same candidates as for the NAT and EUR concepts are also added between Great Britain and France. The cost-effective investments in the MOG candidate transmission lines are shown in Figure 5-39. Invested offshore lines in the MOG are in cyan.

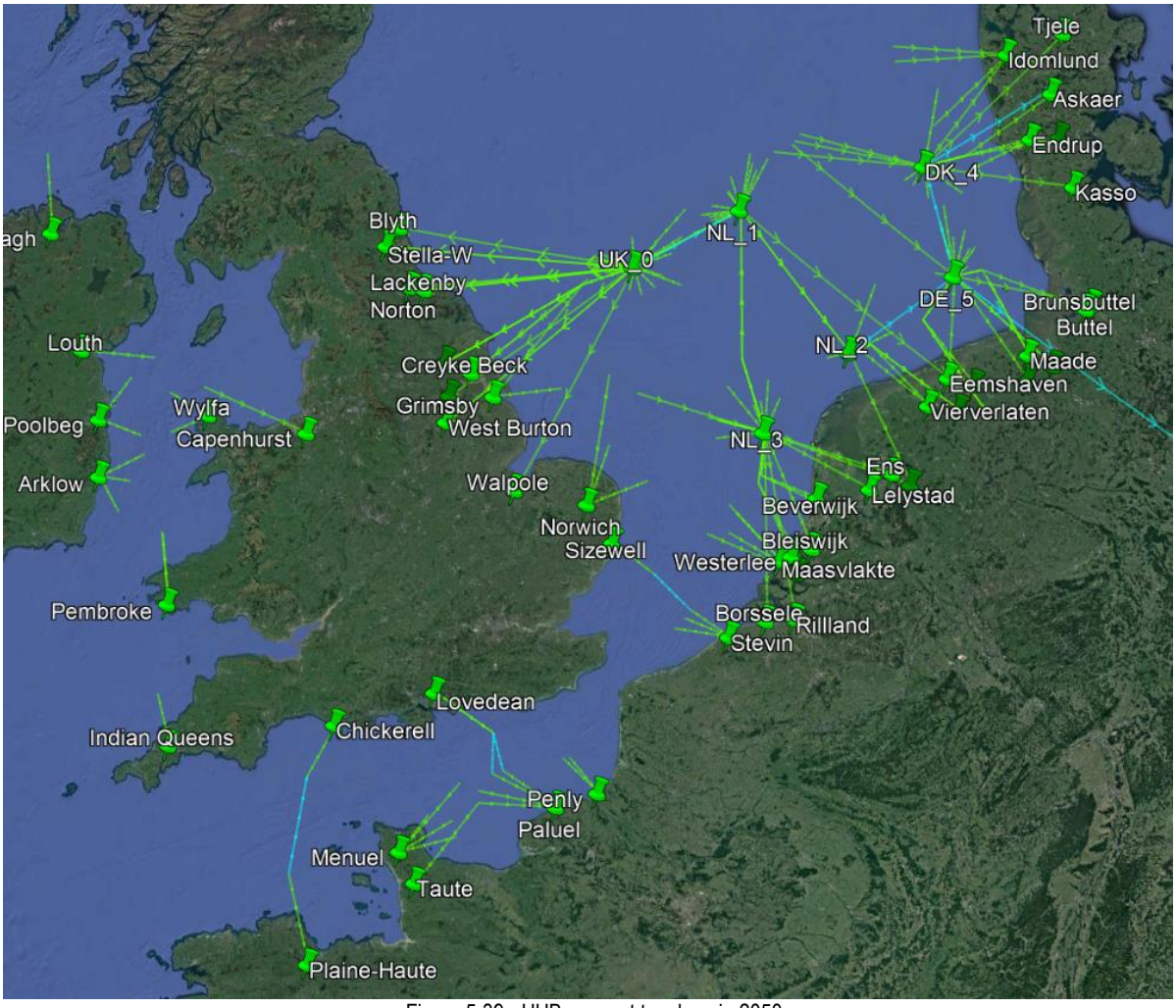


Figure 5-39 - HUB concept topology in 2050.

5.4.3.3.1 GERMANY-NORWAY AXIS

The direct connection from Germany to Norway benefits from a significant investment: 5.6 GW in total. The candidate line from DE_N (mainland Germany) to the HUB DE_5 is also subject to significant investment of almost 5 GW. This means that in this scenario, the algorithm finds that it is more economic to evacuate the wind production to shore and then reinforcing the point-to-point interconnection. It has to be noted that losses and AC grids are not modelled. It is worth noting that the candidate from the German hub to Norway is just at the limit of being seen as economic.

5.4.3.3.2 GERMANY-EASTERN DENMARK AXIS

The direct connection line from Germany to Eastern Denmark is developed by 700 MW in 2040.

5.4.3.3.3 FRANCE-GREAT BRITAIN AXIS

The HUBs have a marginal influence on the France to Great Britain connections. The direct interconnection is significantly reinforced and, in addition, candidate transmission lines via the MOG are also developed: the FR_OFF03-UK_OFF07 line is subject to a transmission expansion as well as the FR_OFF05-UK_OFF07 and FR_OFF06-UK_OFF06.

5.4.3.3.4 THE NETHERLANDS-GREAT BRITAIN AXIS

An additional interconnection capacity between The Netherlands and Great Britain is made available by investing in a subsea cable connecting the Dutch and British hubs for a total of almost 4 GW in 2050.

5.4.3.3.5 BELGIUM-GREAT BRITAIN AXIS

The offshore connection from BE_OFF01 to UK_OFF08 is seen as more economic than the direct BE-GB connection. A 1.0 GW investment in 2030 from Belgium to Great Britain is therefore justified.

5.4.3.3.6 GREAT BRITAIN-NORTHERN IRELAND AND GREAT BRITAIN-IRELAND AXES

A 1.2 GW transmission line is built between Great Britain and Northern Ireland. An interconnector of 1.8 GW with a similar size is built in 2040 & 2045 between Great Britain and Ireland.

5.4.3.3.7 CONGESTIONS ON THE COUNTRY-TO-COUNTRY INTERCONNECTIONS OF THE TYNDP

The HUB structures allow to propose economic investment between hubs of neighbouring countries to increase the transfer capacity. Therefore, there is some significant investment between the German and the Dutch hubs, and between the German and the Danish hubs.

5.4.3.4 STEP 3 - SECURITY ANALYSIS

For the European Centralised Hubs concept, the security analysis depends mainly on the design of the hubs. It is assumed that a careful design of the hubs should allow to stay secure in N-1 conditions.

5.4.4 EUROPEAN DISTRIBUTED HUBS APPROACH

5.4.4.1 TIME EVOLUTION OF THE TOPOLOGY

In this Section, the results are illustrated for both optimisation steps. This represents a potential future topology in the North Sea for the EUR concept and the High wind scenario. The topologies are represented in Figure 5-40 to Figure 5-42. Note that these figures represent also existing/planned interconnectors as well as existing/planned windfarms. It can be observed that the network is composed of radial and multi-terminal connections, and becomes increasingly meshed after 2040. This is similar to the NAT concept. However, cross-border interconnections appear sooner, as soon as wind farms are installed in the Dogger Bank. This is because of the difference in the candidate lines of step 1 and illustrates that the EUR concept allows to reduce the required cable length for projects far from the coasts. In addition, step 2 tends to increase the level of meshing and interconnections in the MOG; this will be further described in Section 5.4.4.3. Similarly to the NAT concept, it is worth keeping in mind that a clustering step had been performed for this scenario in order to decrease the mathematical complexity (as mentioned in Section 5.3.1.1). Therefore; one offshore node seen in the figures may represent several offshore platforms close to each other. Similarly, the lines representing HVDC subsea cables could represent multiple cables in parallel.

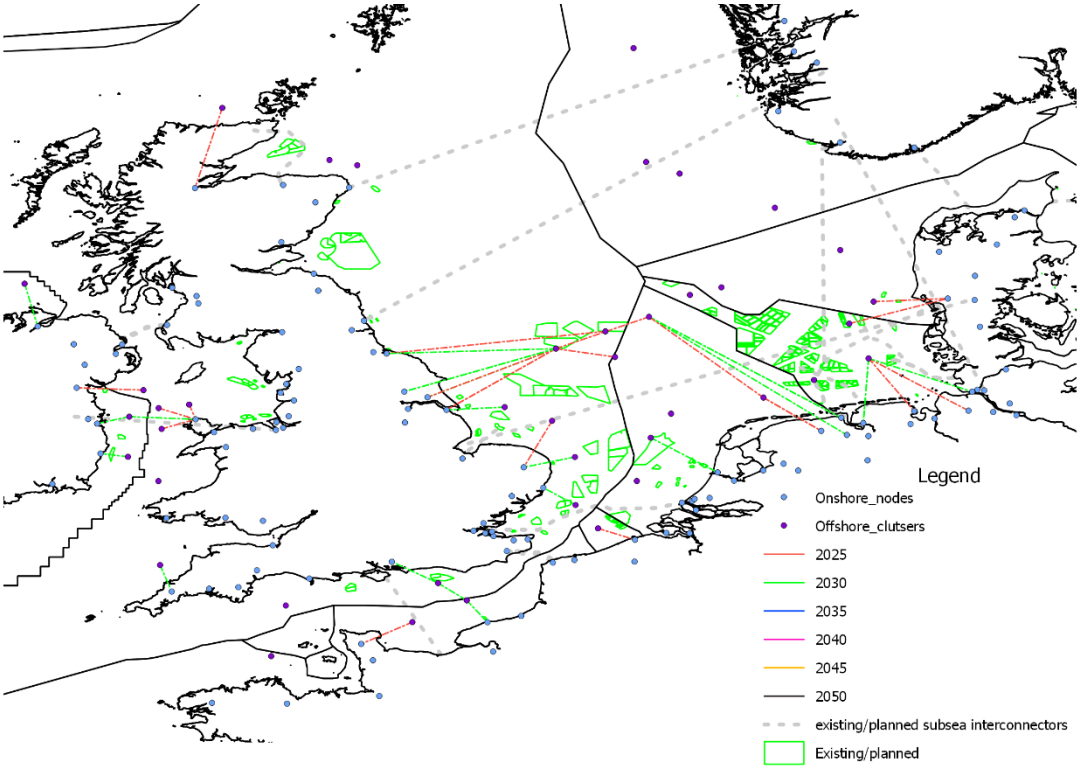


Figure 5-40 - High wind scenario, EUR concept, topology in 2030.

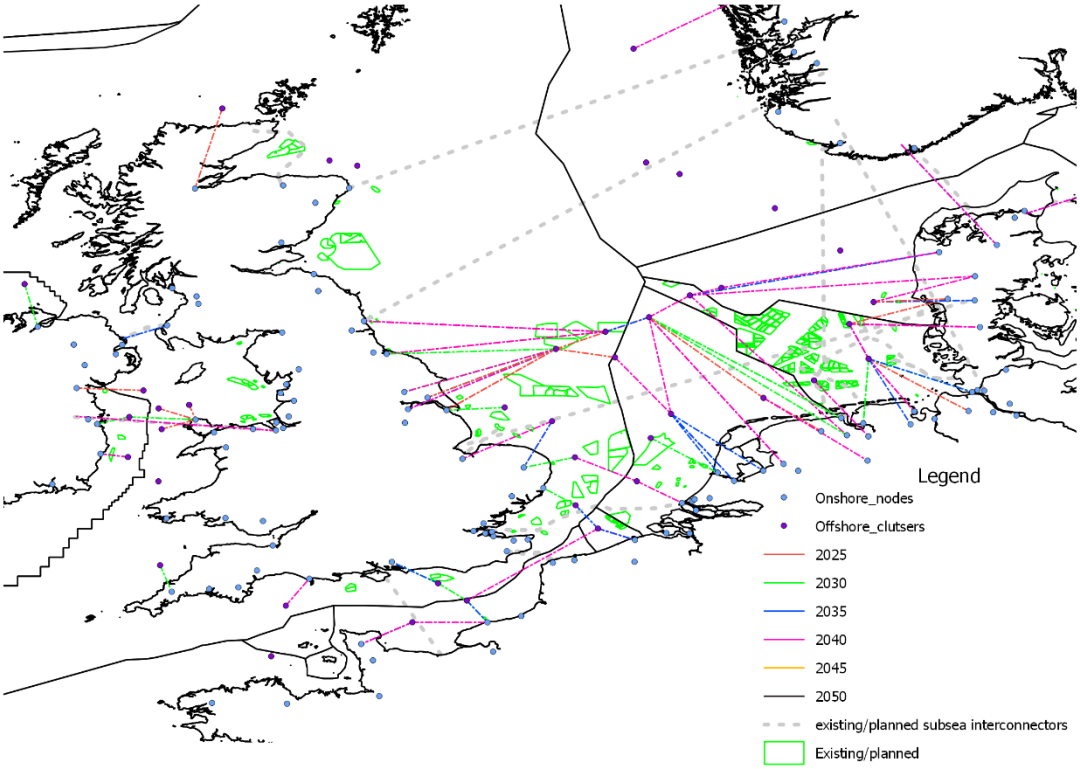


Figure 5-41 - High wind scenario, EUR concept, topology in 2040.

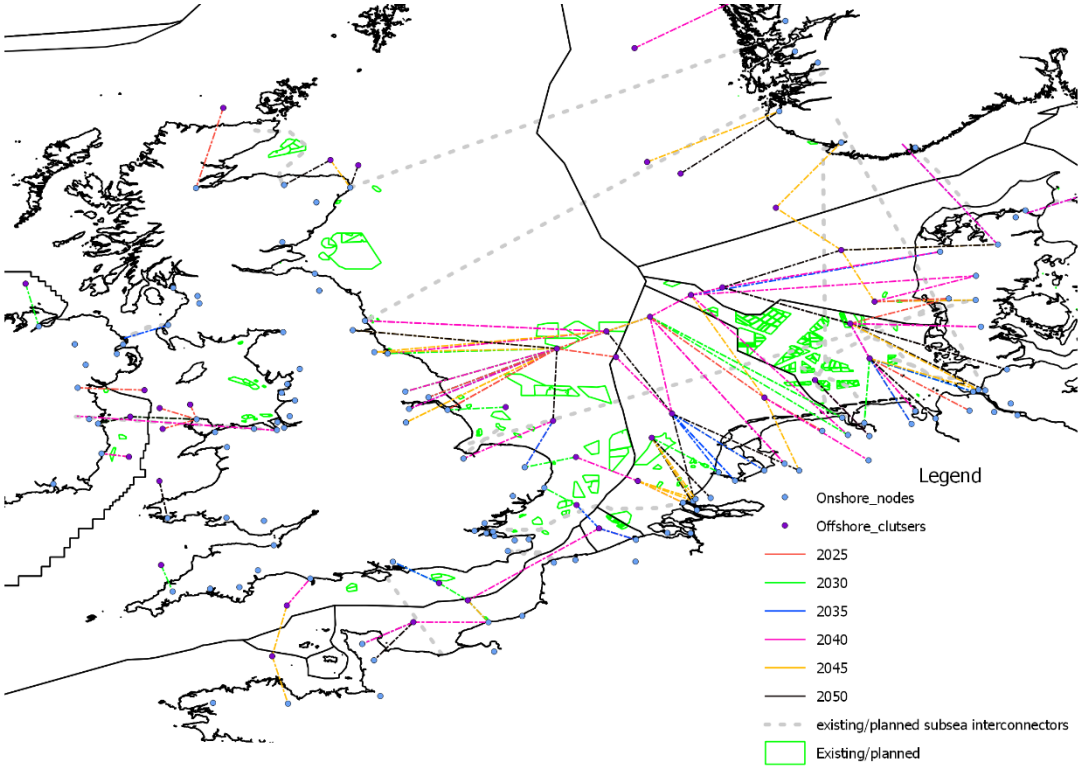


Figure 5-42 - High wind scenario, EUR concept, topology in 2050.

5.4.4.2 STEP 1 - OTEP

The main observations of this step for the EUR case are similar than for the NAT case:

Creation of multi-terminal DC connections

In the EUR case, the OTEP step tends to create multi-terminal DC grid in order to optimise the use of cable rating and therefore to minimise the cable length. This is similar to the NAT concept except that there are no national border constraints in the development of these multi-terminal connections.

Anticipatory investments and modularity

Similarly to the BAU and NAT concept, the EUR concept requires anticipatory investments. The main difference is that the OTEP results for the EUR concept could potentially already lead to an improvement of the cross-border interconnections.

Onshore connections to closest substation (independent on country)

Because of onshore hosting capacity constraint (maximum 4 GW per onshore connection), many onshore candidates are needed. However, the difference with the BAU and NAT concepts is that the EUR concept connects to the closest onshore node even if not from the same country.

5.4.4.3 STEP 2 - OPTIMISATION OF INTERCONNECTIONS

Table 5-12 lists the investments in transmission capacity expansion on the candidate interconnectors. The candidates without investment are removed from the table. Note that, for the sake of clarity, the table also include existing/planned interconnections.

Table 5-12 - Transmission capacity expansion in the EUR concept High wind scenario (in GW). Numbers in black are the existing/planned interconnections, numbers in red are the point-to-point expansions and in blue the expansions via the MOG.

INTERFACE	2020	2025	2030	2035	2040	2045	2050
BE-FR					0.6	0.6	0.6
BE-GB	1	1	1+0.8	1+1.2	1+1.2	1+1.4	1+1.4
DE-DE					5.6	5.6	5.6
DE-DKe	1	1	1	1+1	1+1	1+1	1+1
DE-DKw					0.4	0.5	0.5
DE-GB	1.4	1.4	1.4	1.4	1.4	1.4	1.4
DE-NL				1.1	1.1	1.1	1.1
DE-NOs	1.4	1.4	1.4	1.4	1.4	1.4	1.4
DKw-NOs	1.6	1.6	1.6	1.6+1.1	1.6+3.3	1.6+3.3+1.5	1.6+3.3+1.5
FR-GB	4	6.8	6.8+0.6+0.4	6.8+3.8+1	6.8+3.8+1	6.8+3.8+1.4	6.8+3.8+1.4
GB-IE	0.5	0.5	0.5	0.5+0.6+0.9	0.5+0.6+1.4	0.5+0.6+1.4	0.5+0.6+2.2
GB-NI	0.5	0.5	0.5	0.5	0.5+1.2	0.5+1.2	0.5+1.2
GB-NL	1	1	1	1+0.4	1+1.3	1+3.4	1+4.4
GB-NOs	0	2.8	2.8	2.8	2.8	2.8	2.8

The EUR model connects offshore nodes with the closest onshore substation, even if that substation belongs to another EU country. It also leaves the possibility of investing between offshore nodes located in the North Seas to interconnect the countries. The 2050 MOG for the EUR concept is illustrated in Figure 5-43.

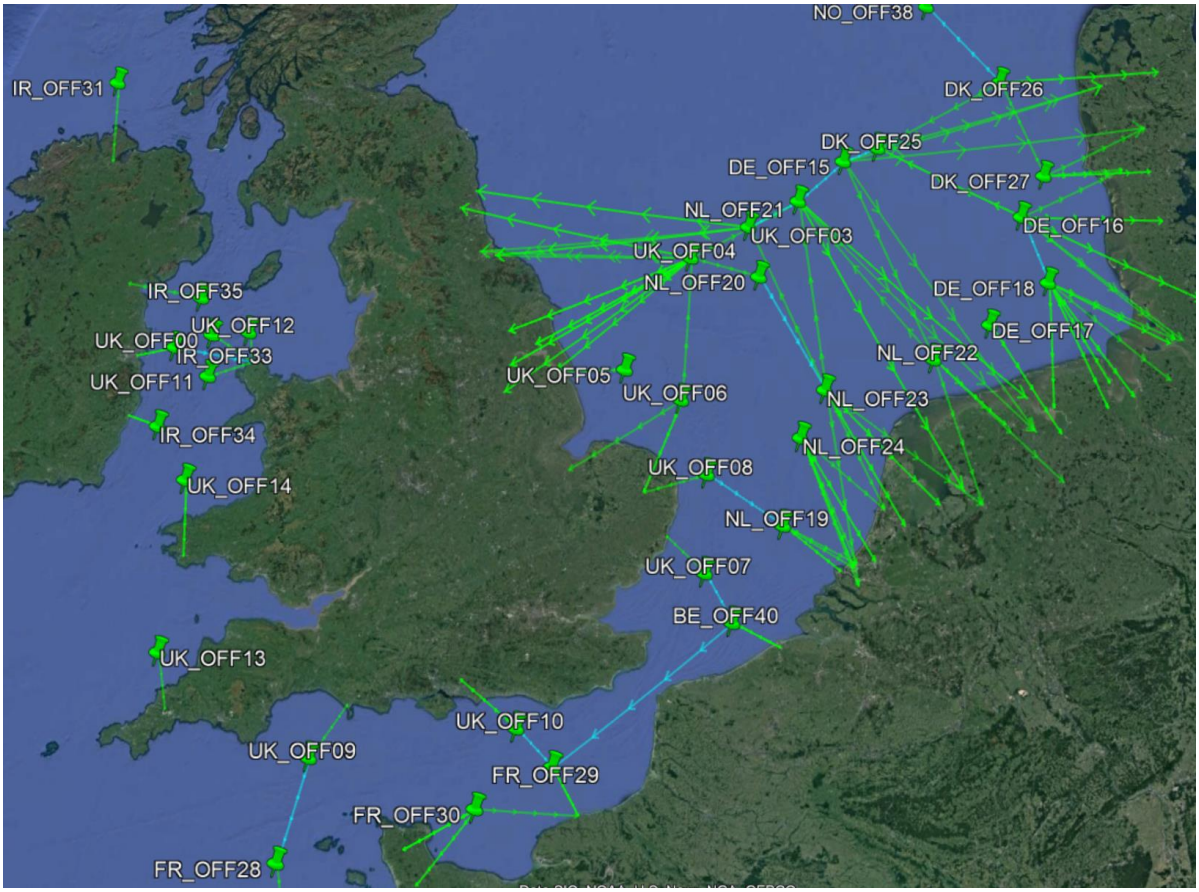


Figure 5-43 - EUR concept topology with offshore expansion from step 2 shown in blue.

5.4.4.3.1 GERMANY-NORWAY AXIS

The BAU investment in a direct interconnector between Germany and Norway is replaced in the EUR by the investments in the direct link between Denmark and Norway (3.3 GW in 2040) and in the offshore lines DK_OFF26-NO_OFF38 linking Denmark to Norway (1.6 GW in 2045) and DE_OFF16-DE_OFF18 meshing the grid between Germany and Denmark.

5.4.4.3.2 GERMANY-EASTERN DENMARK AXIS

The alternative transmission candidates in the EUR case allow to reduce the need for a direct connection between Germany and Denmark East. The offshore line DE_OFF16-DE_OFF18 improves the exchanges between Western Denmark and Germany. This creates a direct energy exchange channel instead of requiring the Germany-Eastern Denmark interconnection to be further expanded (compared to BAU case).

5.4.4.3.3 FRANCE-GREAT BRITAIN AXIS

Compared to the BAU case, the direct interconnection investment from France to Great Britain is reduced by investment in the offshore interconnections UK_OFF10-FR_OFF29 and UK_OFF09-FR_OFF28 (1400 MW spread over 2035 and 2040). The total transmission capacity developed between France and Great Britain in the EUR model is almost identical to the one of the BAU model but at lower cost.

5.4.4.3.4 GREAT BRITAIN-NORTHERN IRELAND AND GREAT BRITAIN-IRELAND AXES

The candidate line IR_OFF33-Wylfa has a sufficient potential for transmission capacity expansion (1.3 GW) and at a cheap enough capital expenditure to make it more interesting than the direct Great Britain-Ireland candidate.

In the EUR case, 0.6 GW of capacity is developed directly from Great Britain to Northern Ireland in 2040 and up to 2.2 GW of capacity is developed through IR_OFF33-Wylfa.

5.4.4.3.5 CONGESTIONS ON THE COUNTRY-TO-COUNTRY INTERCONNECTIONS OF THE TYNDP

The MOG allows to alleviate the congestions on the onshore connections planned in the TYNDP model. In particular, interconnections from France to Belgium, France to Germany, Belgium to Great Britain and Germany to the Netherlands are increased by using the MOG.

5.4.4.4 STEP 3 - SECURITY ANALYSIS

In the EUR case, load flow analyses in the healthy state (no outage) were performed for each target year at maximum wind production. No overload or overvoltage of equipment was observed.

In N-1, droop control is required to avoid over-voltages post-contingency. Special protection schemes might also be need to initiate fast control actions post-contingency to avoid overloads. This is similar to the NAT case.

5.4.5 CABLE LENGTH REQUIRED

The topology developed will be used in Chapter 5 to perform a detailed cost analysis. However, a first estimation based on the total length of the cables required for the topologies allow to determine the potential benefits of each concept. This is illustrated in Figure 5-44. It can be observed that the cable length can be reduced by 5% compare to the BAU in the NAT and EUR concept for step 1. For step 2, the EUR concept uses 30% of cables less than the BAU. In total, this leads to a cable length reduction between 4 and 8% for the NAT and EUR concept compared to BAU. The HUB concept uses more cables with our input assumptions but gain benefits on the platform costs.

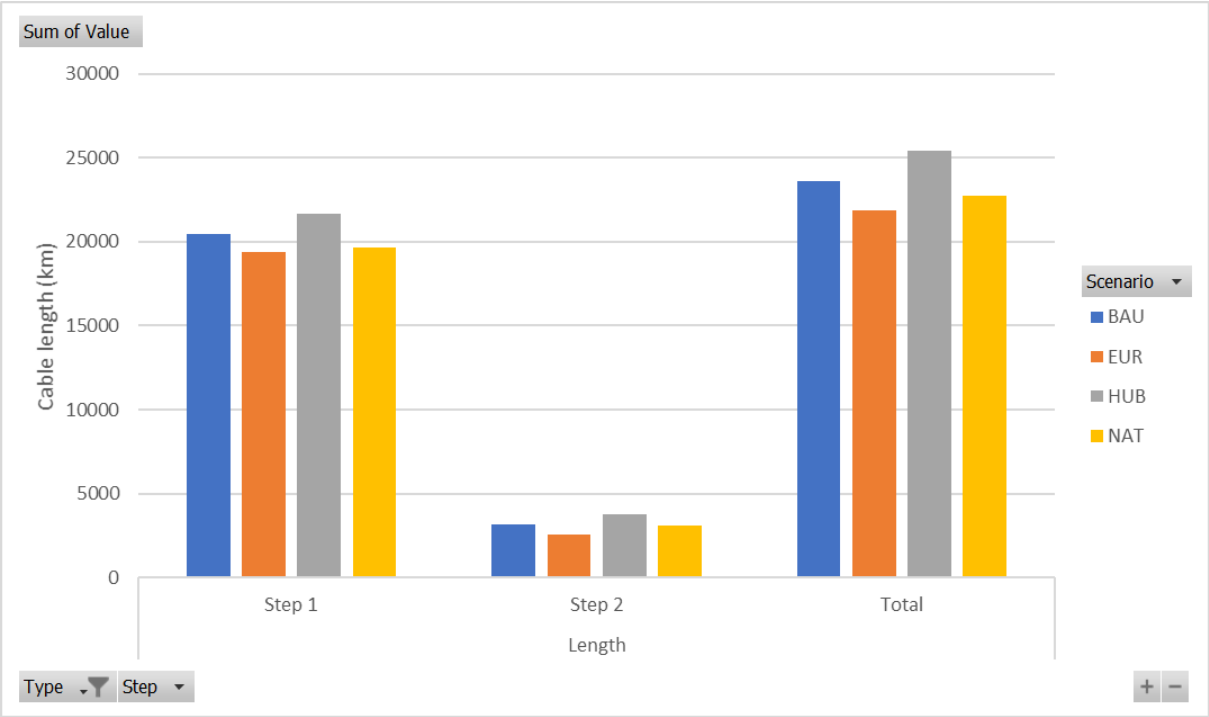


Figure 5-44 - Comparison of cable length for the High wind scenario.

5.5 SENSITIVITY ANALYSIS

While the analysed cases allowed to draw interesting observations, the impact of our starting assumptions had not been quantified. This is extremely important in order to evaluate the robustness of the results against any small changes in the assumptions. During this project, many questions were raised by partners about the following aspects:

- Maximum converter rating on a platform
  - Input assumption: 2 GW
  - Sensitivity: 1 GW, 1.6 GW
- Maximum cable rating
  - Input assumption: 2 GW
  - Sensitivity: 4 GW
- Onshore hosting capacity
  - Input assumption: 4 GW
  - Sensitivity: no constraint, 4 GW + limited onshore investment
- Offshore storage
  - Input assumption: not considered
  - Sensitivity: storage on HUB concept (2 GW to 10 GW on artificial islands)

The sensitivity analysis has been performed only on the step 1 of the optimisation for the High wind scenario, which is illustrative of the influence of the input assumptions. The sensitivity analysis results are represented in Figure 5-45 where the total cable length has been calculated for each simulated case. A colour code identifies which assumptions have led to the most extreme results. For the NAT, EUR and HUB concepts, the best results are obtained without onshore hosting capacity constraint and with 4 GW cable.

The main observations of the sensitivity analysis are the following:

- The meshed scenarios performed better than the two others for all cases. The European Decentralised Hub performs always slightly better than the National concept. The Business-as-Usual remains competitive when platform size and cable rating are similar. If not, this concept can be significantly more expensive.
- The BAU concept is the most sensitive to changes in the initial assumptions with up to 50% cable length increase if the platform sizes are limited to 1 GW instead of 2 GW.
- The National Distributed Hubs and European Distributed hubs are much less sensitive to the platform size and perform the bests with high onshore capacity at some specific onshore connection points.
- Storage is needed for the HUB concept to have similar cable length as the National and European Distributed Hub concepts. This emphasises the benefits of multi-purpose energy solutions for the Centralised Hub concept.
- The onshore hosting capacity constraints affect significantly the design of the offshore grid. This is valid for all concepts.
- The total cable length can be reduced by using larger cables. However, potential additional cables for security (N-1), controls or protections have not been studied and are not included in this sensitivity analysis.

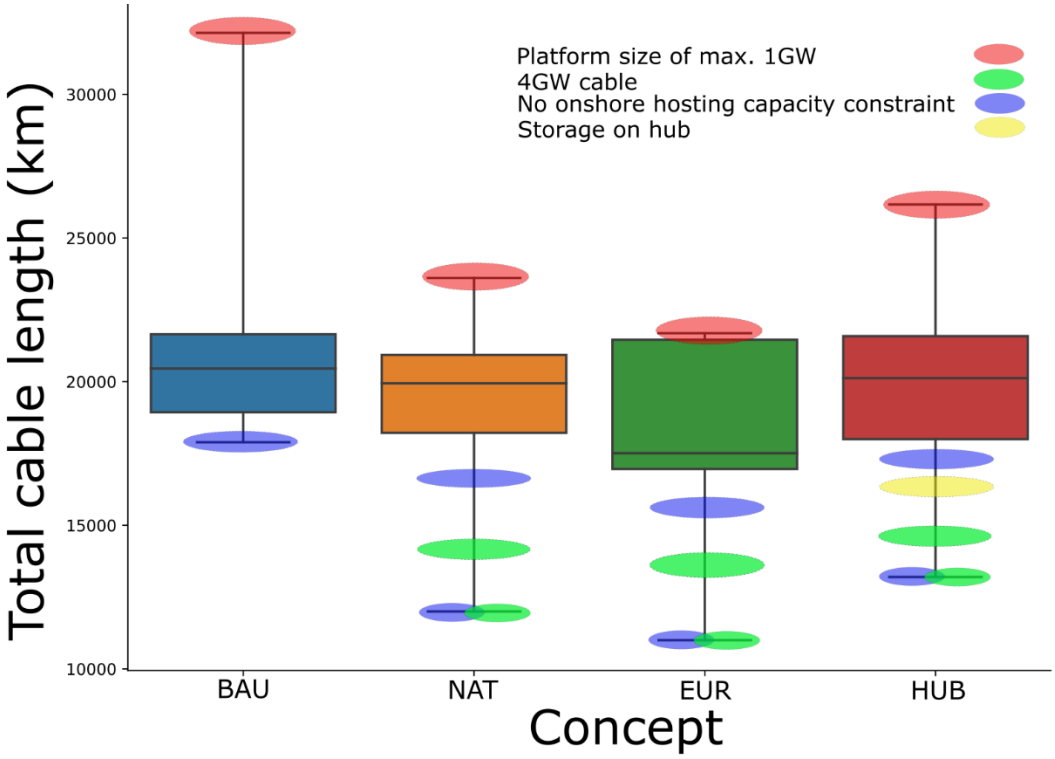


Figure 5-45 - Sensitivy analysis on total cable length of MOG for the High wind scenario.

5.6 CONCLUSIONS AND KEY MESSAGES

This Chapter has presented first the methodology followed to propose potential realistic topologies of a future offshore grid in the North Seas. This methodology combined optimisation of the cable length and use of a market model to determine to take into consideration costs but also benefits of cross-border interconnection via the MOG. A dedicated optimisation tool has been used for the sake of study in order to determine the least-cost topology able to evacuate the installed offshore wind capacity. In addition, a market model based on the TYNDP dataset has been implemented in order to determine the most economic investments to reinforce interconnections between the North Sea countries.

The results have been presented in detailed and illustrated by maps describing potential time evolution of the offshore grid. This has been done separately for each concept and for each wind scenario, and allows the interested reader to observe (and criticise) the evolution of the offshore grid over time. The key messages that could be taken from these results are:

- First message: the proposed radial connection appears to be a competitive option and is the first building block
    - Optimisation (and standardization) of 525kV 2 GW platform design
    - Coordinate maritime spatial planning is key to reach 2 GW by “aggregating” windfarms
    - 2 GW requires around 200-400 km^2 which appears realistic from the GIS study and allows AC connections to an offshore HVDC platform
    - The sensitivity analysis outlined that the radial solution remains competitive if the maximum platform size and cable rating are similar. If this is not the case, the radial solution becomes significantly more expensive.
- Second message: the combined use of the offshore grid for wind evacuation and interconnectors is an important driver for meshing/multi-terminal

- Third message: in all concept and scenarios, the topology will evolve gradually from a few multi-terminal connections to a more complex structure. Eventually, a backbone will interconnect several multi-terminal connections. It has also been shown that all wind scenarios require a high level of interconnection.
- Fourth message: reduction in cable length from one concept to another is sensitive on input assumptions. Depending on the assumptions, the difference is very significant or not. If the difference is small, the costs of other aspects (such as protection devices, platforms, advanced controls) have to be considered.
- Fifth message: the Dogger Bank seems an ideal candidate to form a backbone (or “hub”) because of the short distances between offshore wind plants. There are no clear benefits to connect all the multi-terminal structures together to form a single grid (meaning extra-costs and complexity).
- Sixth message: the results are very sensitive to the input assumptions and the sensitivity analysis has shown that:
    - Reducing the platform size is very detrimental for the BAU concept
    - Increasing onshore hosting capacity reduces significantly the total cable length required for all concept but is more beneficial for the NAT, EUR and HUB concepts.
    - Increasing cable rating can theoretically reduce the most the total cable length but needs to consider more constraining N-1 system security aspects.
- Seventh message: for the High wind scenario, an increase of the interconnection capacities is needed but is not enough to evacuate all the produced wind energy. Indeed, there are some periods of the year where offshore generation exceeds electricity demand of connected countries. Therefore, large-scale storage (onshore and/or offshore) will be needed in all concepts.

To conclude, it has been observed that the National and European approaches can be seen as the least-regret approach composed of a mix of radial and multi-terminal connections. These concepts perform always better than the two others for all the simulated scenarios. Moreover, they allow to grow gradually the network from multi-terminal to several small HVDC meshed networks when the technology will be ready and economic.

6 COSTS OF THE TOPOLOGIES

6.1 SUMMARY OF THE CHAPTER

The Chapter describes the methodology of going from topologies to the cost calculation of main components, protection system costs and operational costs. Then, for each of the concepts, the total cost is given in terms of capital costs (including protection) and operational costs.

Compared to the BAU concept, the HUB concept has 7 % lower costs, while the NAT and EUR concept have 4 and 8 % higher costs in the High wind scenarios. Breaking down the costs for the Central and Low wind scenarios, it is shown that the decrease in cable length throughout the scenarios, as shown in Chapter 5, also has a positive influence on the share of cable costs throughout the scenarios. It is also shown that the reduction in cable length from the BAU concept to the NAT and EUR concept is relatively minor, while the need for a protection system then increases the overall capital costs significantly. Additionally, in the HUB concept, artificial islands significantly impact the capital cost for support structures. However, it is also shown that this impact is dramatically reduced when the artificial islands replace a smaller amount of HVDC platforms.

The Chapter is concluded by validating the assumptions on main components used against existing HVDC projects as well as running a sensitivity analysis on the input factors. It is shown here that the model is quite robust to the input figures, where all possible options fall within the bandwidth of the uncertainty on the input figures.

6.2 INTRODUCTION

The costing of the concepts requires a detailed breakdown of the topologies described in the previous Chapter into the main (HVDC) components that are used to construct the grid. In order to do so, a methodology has been developed that was agreed upon by the WP12 and WP4 members. This method starts with the gathering of the input data, then preparing the input for a detailed breakdown, then identifying the main components present in the grid and the design of the protection system and finally the cost calculation. This method is further described in the following Section.

6.3 METHOD

The method is based on the outcomes of other WPs, in particular findings regarding technology advancement from WP2-6 and specifically on the recommendation for the CBA methodology from WP7. A descending approach from a full-scale topology to a component level is proposed as shown in Figure 6-1.

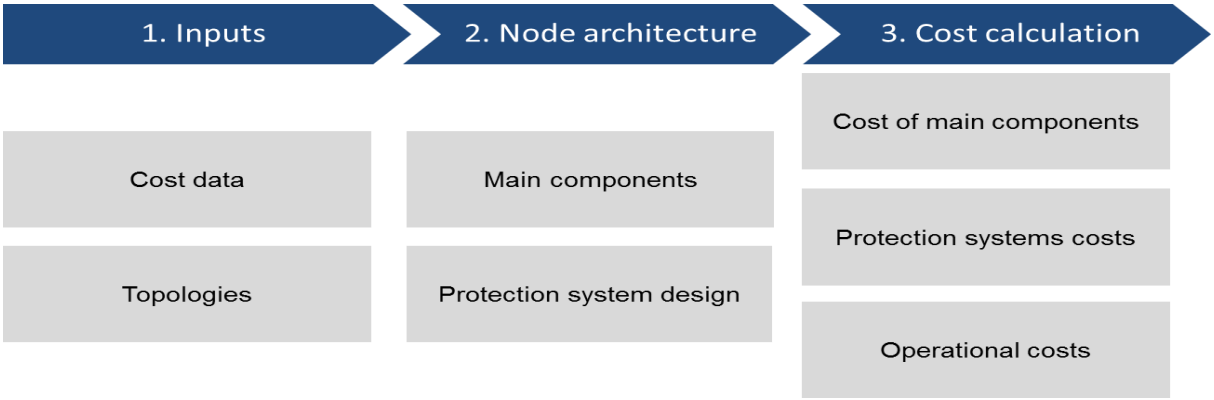


Figure 6-1 - Costing method visualisation.

1 **Inputs**: The first step is to obtain cost data for all the necessary components for an offshore grid. The cost data collection is described in Section 6.3.1. Then, the full topology of the grid including clustering of the onshore connection points and offshore OWFs, as was described in Chapter 5 is processed for use in the CBA, as is described in Section 6.3.2.

2 **Node architecture**: Offshore nodes are designed according to specific criteria in order to represent the clusters in a greater level of detail, up to the main components of a node: the converters, cables, platforms and transformers. Distances impact the choice of technology, which means a selection between different components can be made. For this purpose, a decision-making approach was developed within WP12. Then, the cost of the grid "barebones" can be estimated, as is described in Section 6.3.3.

   Further, a protection system is designed taking into account security constraints, anticipated power flows and protection equipment capabilities, as is explained in Section 6.3.4. The work done by other WPs was incorporated in the analysis and consultations with technical experts were held.

3 **Cost calculation**: At the final stage, once the so-called bill-of-materials of the hub is obtained, the total cost of the hub can be estimated as the sum of the investments in main components and protection equipment (breakers and switchgear) during the construction period (from 2020 up to 2050) and operational costs during the lifetime of the equipment. The net cost of the MOG is then derived as the sum of the costs of all hubs, their protection system and connections, plus the operational expenditures depreciated from the year in which they apply. The guidelines for the CBA from D7.11 were followed, as is shown in Section 6.3.5.

6.3.1 INPUTS: COST DATA COLLECTION

These components are then costed according to the costs that are given in the Cost Data Collection report. These costs are, where possible, given to be as complete as possible and include the direct material cost, labour cost, R&D cost, a profit margin and installation cost.

The methodology to obtain these costs is given in Appendix IV, the methodology for cost decline over the period in Appendix V. The report aims to deliver cost figures with a margin of ±30 %, which is a common margin in cost engineering studies. The Cost Data Collection study is necessary due to the immaturity of the market and the therefore scarcely available data. The Cost Data Collection report is focussed only on the specific offshore grid components such as HVDC converters, platforms and DC cables and the onshore connection point components such as the onshore converter station. This is in line with the scope of the project.

For the Cost Data Collection report, data was collected first from public, scientific and DNV GL internal sources or otherwise estimated bottom-up. Then, the collected costs are validated through public sources and then verified with vendors. These steps are necessary to expand the data as well as verify the reliability of the data and merit the existence of this exercise.

The costs for components are given in a range in the Cost Data Collection report in order to capture the different environments that some of the components have to face. For example, the water depth has an influence on the cost for a DC platform. However, an average value is assumed in the cost model. This is because the cost model aims to estimate differences between the concepts. In each of the topologies, many of the components are situated in the exact same area, which means their actual cost would be the same. In order to capture the range in input data a sensitivity analysis is applied in Section 6.5.2. Additionally, the costs for artificial islands must be specifically mentioned, as this is based on an assumption made within the project. From internal sources, the cost

of an island that could host 10 GW of converters was obtained and used within the project, but was kept constant regardless of the hosting size of the island. The influence of a range in costs on the final figure for the HUB concept is also described in Section 6.5.2.

6.3.2 INPUTS: TOPOLOGIES

From the topology generation, the number, length and capacity of the DC cables was obtained for each of the time steps. The data of these cables can directly be used in the costing, as cost figures for these components are given in Euro per kilometre for different capacities. The clusters and their development in size throughout the time steps do not yet represent single hubs and thus are first broken down into offshore converter stations. These offshore converter stations are sized according to the ratings available in the cost data collection and the DC cables originating from the clusters. This allows to calculate the length of AC cabling from the OWFs to their converter station and the number and rating of the offshore converter stations. The onshore converter stations also originate from the topology generation. An overview of the data and its match with the costs data unit can be seen in Table 6-1.

Table 6-1 - Breakdown of the topology data in the components present and the cost data unit applicable to the data.

TOPOLOGY DATA	TOPOLOGY UNIT	COMPONENTS PRESENT	COST DATA UNIT
DC cables	Number (-), length (km) and rating (MW)	DC cables	€/km for different ratings (MW)
Offshore clusters	Length of AC cabling Number (-) and rating (MW) of converter station	OWFs, AC cables Offshore converter station	*OWFs*: none *AC cables*: €/km for different ratings (MW) *Offshore converter station*: € for different ratings (MW) for platform and converter
Onshore nodes	Number (-) and rating (MW)	Onshore converter station	€ for different ratings (MW) for converter

6.3.3 NODE ARCHITECTURE: MAIN COMPONENTS

At this stage, the technology is imposed on a part of the grid. In order to then assign components to this, the grid is imagined to be a multitude of DC radially connected offshore windfarms, presented in Figure 6-2 below. An offshore windfarm (OWF) is connected through its AC transformer (OWF-ACT) with an AC cable (ACC) to an offshore converter (OFC). The AC transformer and offshore converter are situated on top of their respective offshore support structure (OFSS). From the offshore converter a DC subsea cable (DCC) transports the offshore generated wind energy to land, where an onshore converter (ONC) converts the energy back to AC in order to feed it into the grid.

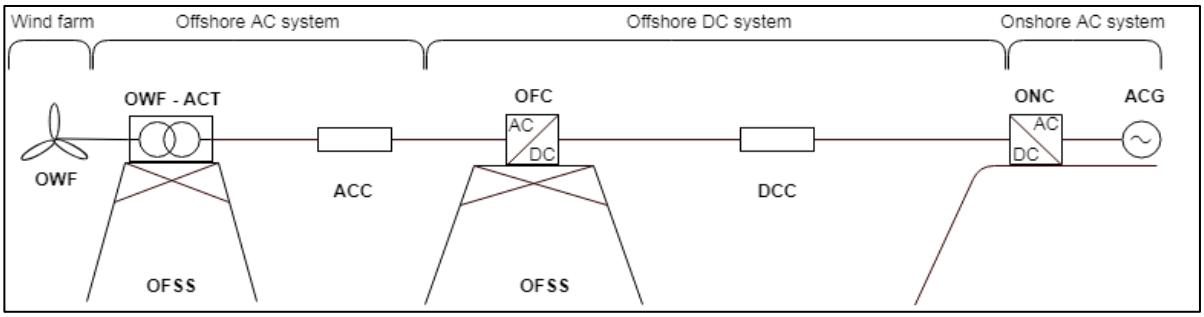


Figure 6-2 - Main grid components for costing.

There are, however, some exceptions to this typical part of the grid. With different distances between the systems, different components as presented in the figure above are required. First, the distance between the OWF and offshore converter has an impact on the choice for the AC transformer and its corresponding platform. Second, the type of offshore support structure for the offshore converter may be a platform in all concepts, or an artificial island in the HUB concept. Third, the cable from the offshore converter may go to shore in all concepts, to the DC busbar of a converter on another platform in the NAT and EUR concepts or to the DC busbar of a converter on an island in the HUB concept. These choices are summarised in a decision tree in Figure 6-3 below. The entire MOG is a mixture of these combinations of technologies, where certain components may get shared (e.g. islands) or connected (e.g. through DC cables to other terminals).

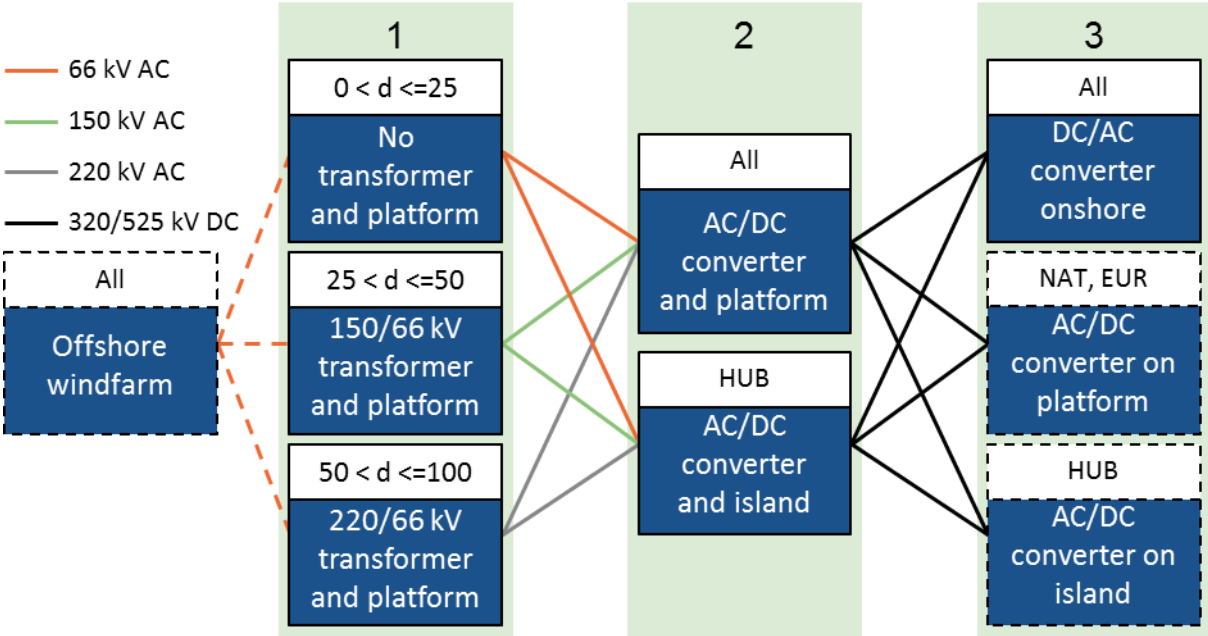


Figure 6-3 - Decision tree for components in the topologies. Distance (d) from OWF to node in kilometres. Components with solid lines are costed, components with dashed lines are either not costed at all or costed in another step.

6.3.4 NODE ARCHITECTURE: PROTECTION SYSTEM DESIGN

Development in DC protection in recent years has enhanced technical readiness of DC breakers (DCCBs) and DC protection strategies. Several protection strategies have been proposed, such as fully-selective (FS), non-selective (NS) and partially selective (PS) [17, 18]. The required performance for the protection system depends on acceptable operation of both DC and AC grids during and after the protection sequence (from fault inception to grid restoration) and can be characterised by a set of specific key performances indicators (KPIs) [18, 19]. More particularly, the DC grid may experience a temporary power flow interruption which may impact the stability of the surrounding AC grids [20, 18]. The maximum grid area that may experience a temporary power flow interruption

can be a single line (with high speed FS protection strategy), a part of the grid (with PS protection strategy) or the entire DC grid (with NS protection strategy), which will lead from partial to full temporary interruption of the DC power flow at converter terminals.

Besides required performances, each protection strategy is also characterised by its CAPEX and OPEX. It is shown in Deliverable D4.7 that the CAPEX of protection system is dominated by the CAPEX of DCCBs, including breaking devices, reactors and surge arresters. Additionally the costs associated with the weight and volume of the DCCBs, especially if installed on an offshore platform, can be significant. FS protection strategy, which uses expensive high speed DCCBs, has been shown to be more expensive than NS protection strategy using more cost effective slow speed DCCBs. Also, it is shown that all protection strategies have OPEX lower than 10% of DC grid total OPEX. The challenge is then to be able to determine the protection system design which will respect the required protection performances at the best cost.

In case of large DC grids, a solution to avoid AC instabilities might rely on the implementation of PS strategy. The PS strategy concept consists in splitting the grid into different areas (each of them being separated by a dedicated firewall interface, typically a high speed DCCB) on which an appropriate protection concept (more generally NS, but it can also be FS) is applied. A methodology based on such grid splitting concept is proposed in Deliverable 4.7, which highlights the protection strategies' areas on a part of the grid obtained from the topology generation. In each area, the protection system and the rating of associated components are specified and acceptable operational KPIs are assumed. Protection system costs are first computed for each area and then the full system in order to build a relation between full DC grid protection system design, specification and associated costs. In the cost model, an assumption is made on the protection system, as this is not fully computable for each concept separately. Therefore, a separation is made between parts of the grid that would require protection and parts of the grid that would not. On the part of the grid that would require protection, an 8,7 % margin is applied for the protection system, corresponding to the FS FDCCB protection strategy as shown in Table 6-2.

Table 6-2 - Comparison of several protection strategies on CAPEX and time to restore active power KPI.

	PROTECTION SYSTEM CAPEX (P.U.)	PROTECTION SYSTEM CAPEX RELATIVE TO FULL DC GRID CAPEX (%)	MAX NUMBER OF CONVERTER TERMINALS WITH ACTIVE POWER DISTURBANCE	MAX TIME TO RESTORE ACTIVE POWER (MS)
NS CB (1 area= full DC grid)	1	4.5	35*	190*
PS with NS CB (2 areas)	1.02	4.6	28*	200*
PS with NS CB (11 areas)	1.14	5.2	15**	~200**
FS SDCCB (29 areas = 29 single lines)	1.7	7.7	15*	150*
FS FDCCB (29 areas = 29 single lines)	2	8.7	9*	100*

(* Observed in simulation ** Expected, not simulated)

6.3.5 COST CALCULATION: COST OF MAIN COMPONENTS, PROTECTION SYSTEM AND OPERATIONAL COSTS

The previous Sections describe the method to obtain the total number, rating and, where applicable, length of AC cabling, AC platforms and transformers, AC/DC converters and DC platforms and islands, DC cabling and

onshore DC/AC converters. The total cost can then be calculated using this gathered input. The way this can be done is described in [21] and constitutes of calculating two major cost components:

- CAPEX – the capital expenditure indicator reports the capital expenditure of a project, which includes elements such as the cost of obtaining permits, conducting feasibility studies, obtaining rights-of-way, land, preparatory work, designing, dismantling, equipment purchase and installation. It is calculated by multiplying the necessary components for grid expansion by the respective cost and is expressed in Euros.
- OPEX – the operating expenditure is based on the project operational and maintenance costs. OPEX of all projects must be given on the actual basis of the cost level with regard to the respective study year (e.g. for TYNDP the costs should be given related to 2018) and expressed in Euro per year. OPEX interacts with CAPEX where OPEX is expressed in percentage of CAPEX. As such the OPEX is constant throughout the lifetime of the respective component. It is therefore also a more simplified figure that does not account for all contributors to OPEX figures usually calculated for an electricity grid, such as redispatch costs, curtailment (although this is part of the CBA) and opportunity cost for valuing the offshore grid under uncertainty.

In order to perform further calculations with the total expenditures of the project, CAPEX can also further be used to calculate the depreciation of the component. The depreciation is dependent of the lifetime of the component and can be used to express the CAPEX in an annual figure. The residual value of the component after its lifetime is set to zero, in accordance with Deliverable 7.11. As explained in [22], a lifetime of 25 years is assumed as recommended by ACER and adopted in the ENTSO-E Guidelines. Although 30 years (or maybe even longer) might be more befitting offshore assets, the last years of the economic lifetime of assets have a limited contribution to the aggregate value of depreciation. The difference between a 30 year or 25 year lifetime is therefore marginal, which is why a 25 year lifetime is adopted. The CAPEX and OPEX can also be discounted to 2020 Euros to account for monetary variations and inherent uncertainty that comes with future investments. A discount rate of 4 % will be used for this.

As mentioned before, assumptions that are used are in line with the ACER recommendation. The assumptions that are of direct influence on the cost calculation that are mentioned in this Chapter are summarised in Table 6-3.

Table 6-3 - Assumptions for the cost calculation.

COST	VALUE
Cost for components	Average of value given in Cost Data Collection
Onshore grid reinforcement cost	Only close to shore
Protection system	FS FDCCB percentage assumed
Depreciation or lifetime	25 years
Discount rate	4 %
Cost of temporary construction	Assumed included in CAPEX
Workforce training cost	Assumed included in CAPEX
Decommissioning cost	Not taken into account
Re-dispatch cost (part of OPEX)	Not taken into account
Curtailment of RES (part of OPEX)	Not taken into account
Opportunity cost of valuing the offshore grid	Not taken into account

6.4 RESULTS PER GRID TOPOLOGY

The expenditures for each grid topology may be expressed in two figures, as was described in Section 6.3.5: the CAPEX and the OPEX. In the following Section, each of these high-level indicators will be presented first for the High wind scenario to give an impression of the development and build-up of the cost indicators throughout the period. For the Central and Low wind scenario, these indicators are presented in Appendix VI. Then, a more in-depth analysis of the contributors to the CAPEX is presented for each concept, where differences amongst the concepts are described for all wind scenarios.

6.4.1 COMPARISON OF TOTAL COSTS FOR THE HIGH WIND SCENARIO

For the High wind scenario, the CAPEX and OPEX are shown in Table 6-4 below, where each are first given per each five-year period after which their cumulative figure is shown. It can be seen from these figures that the HUB concept has the overall lowest CAPEX, amounting to 172.0 bn€ by 2050. The BAU concept follows with 186.6 bn€, after which the EUR and NAT concept have cumulatively similar costs: 194.9 bn€ and 200.7 bn€ respectively. The same order can be seen for OPEX, as these indicators are based on the CAPEX. The indicators are not discounted to 2020. Combined, the costs for the HUB concept are 7 % lower than that of the BAU concept, while the NAT and EUR concept are 4 to 8 % more expensive, respectively. See Table 6-5. The decrease in costs for the HUB concept can be largely attributed to the artificial islands replacing the highly expensive support structures for offshore converters. The increase in costs for the NAT and EUR concept can be found in the meshing, including the cable connection costs on a platform and the protection system. This is not offset by the decrease in cable length.

Table 6-4 – CAPEX and OPEX in bn€ throughout the analysed period for each of the concepts in the High wind scenario. Note that these figures have a ±30 % uncertainty on cost data input.

KPI	CONCEPT	2025	2030	2035	2040	2045	2050	TOTAL
CAPEX	*BAU*	27.47	28.21	22.28	43.41	34.40	30.81	186.6
	NAT	27.03	30.51	23.82	42.80	38.55	32.22	194.9
	HUB	31.90	29.98	20.33	32.34	28.67	28.66	171.9
	EUR	29.86	31.94	24.03	42.75	37.82	34.29	200.7
OPEX	*BAU*	1.6	4.4	6.8	10.3	14.1	17.3	54.5
	NAT	1.6	4.5	7.1	10.6	14.7	18.2	56.7
	HUB	1.9	4.9	7.2	9.9	12.9	15.7	52.5
	EUR	1.8	4.9	7.6	11.1	15.2	18.7	59.3

Table 6-5 - Cumulative CAPEX and OPEX in bn€ and comparison for each of the concepts in the High wind scenario.

KPI	CONCEPT	TOTAL
Cumulative Investment & Operational Costs	*BAU*	241.10
	NAT	251.60
	HUB	224.40
	EUR	260.00

KPI	CONCEPT	TOTAL
Cumulative Investment & Operational Costs comparison	*BAU*	0%
	NAT	4%
	HUB	-7%
	EUR	8%

Some fluctuations of the increase in CAPEX can be seen throughout the periods for each concept. Especially the decrease in the additional CAPEX from 2030 to 2035 (i.e. 33.5 bn€ and 23.1 bn€ in NAT) is significant. After this period a high rise of CAPEX in 2040 is experienced, more than doubling compared to 2035. This is especially peculiar considering the fact that the increase in generation is far more fluent as was shown in Table 3-2 in Section 3.3.3. However, it is not the increase in generation that influences the costs but rather the components used to transport this generation.

In Table 6-6 below, the capacity of offshore stations, the total amount of cabling, the amount of only offshore cabling and the capacity of onshore stations for interconnection are presented. In 2035 it can be seen that the amount of capacity added in offshore stations is lower than in 2030. These anticipatory investments influence the costs such that the investment in 2035 is lower than in 2030 in each of the concepts. Additionally, even though more onshore stations are constructed for interconnection purposes, the amount of total additional cabling decreases slightly in 2035. In 2040, the high increase in costs compared to 2035 has several factors. Again, there are some anticipatory investments in the capacity of the offshore stations for the period 2045, although the differences are not as large as between 2030 and 2035. The largest impact in costs are found in the amount of cabling, which is impacted by three factors: the capacity of offshore cabling due to meshing in the NAT and EUR concepts, the increase in point-to-point interconnection and the shift of the offshore grid away from close to shore and towards far in-sea areas. Especially in this period the point-to-point interconnection is established between onshore points that have significant distance between each other, while in 2035 the length of interconnection cabling remains relatively small. It is therefore mainly the total amount of cabling in 2040 that influences the high increase in costs compared to 2035 and even compared to 2045.

Table 6-6 - Amount of additional cabling, offshore cabling and onshore stations in each period for each concept.

		2025	2030	2035	2040	2045	2050
Offshore stations (GW)	*BAU*	25.9	27.2	22.8	39.7	39.4	37.5
	NAT	26.9	29	25.7	43.1	41.2	42.3
	HUB	34.3	31.2	22.5	40.7	36.6	40.5
	EUR	29.1	28.4	25.1	42.3	40.3	46.1
Cabling (1000 km)	*BAU*	2.6	2.7	2.4	6.6	4.2	4.1
	NAT	2.6	2.8	2.7	6.0	4.4	4.4
	HUB	2.9	3.4	2.9	5.8	4.5	5.1
	EUR	2.8	3.2	2.9	6.1	4.2	4.5

		2025	2030	2035	2040	2045	2050
Offshore cabling (GW)	*BAU*	0.0	0.0	0.0	0.0	0.0	0.0
	NAT	1.6	7.0	6.4	21.8	32.3	8.0
	HUB	0.0	1.2	1.4	0.0	0.7	0.0
	EUR	6.8	6.8	5.6	13.2	24.3	17.6
Onshore stations for interconnection (GW)	BAU	0	0	6.4	12.8	0.7	0
	NAT	0	0	4.7	7.5	0	0
	HUB	0	4	9.8	4.7	2	0
	EUR	0	1.2	4.2	5.1	0	1

6.4.2 COSTS OF BUSINESS-AS-USUAL

The CAPEX for the BAU concept are broken down into the specific components present in the grid. Presented in Figure 6-4 are the CAPEX for AC components, the DC stations, protection components, the cabling for wind energy evacuation, the direct interconnection cabling and the onshore stations. In the BAU concept the main cost drivers in the cumulative CAPEX over the whole period are the offshore DC stations. The platforms, together with the offshore AC/DC converters, make up around 50 % of total costs in each of the scenarios. Other major categories include the cabling to shore and the onshore stations. Of course, there are no costs for the protection system in the BAU concept. The influence of the location of the generation can be seen in the contribution of the cabling to the total costs, which decreases throughout the scenarios as average distance to shore also decreases. As the infeed of offshore wind energy differs throughout the scenarios, there is more need for point-to-point interconnection, for which the costs increase both absolutely and relatively.

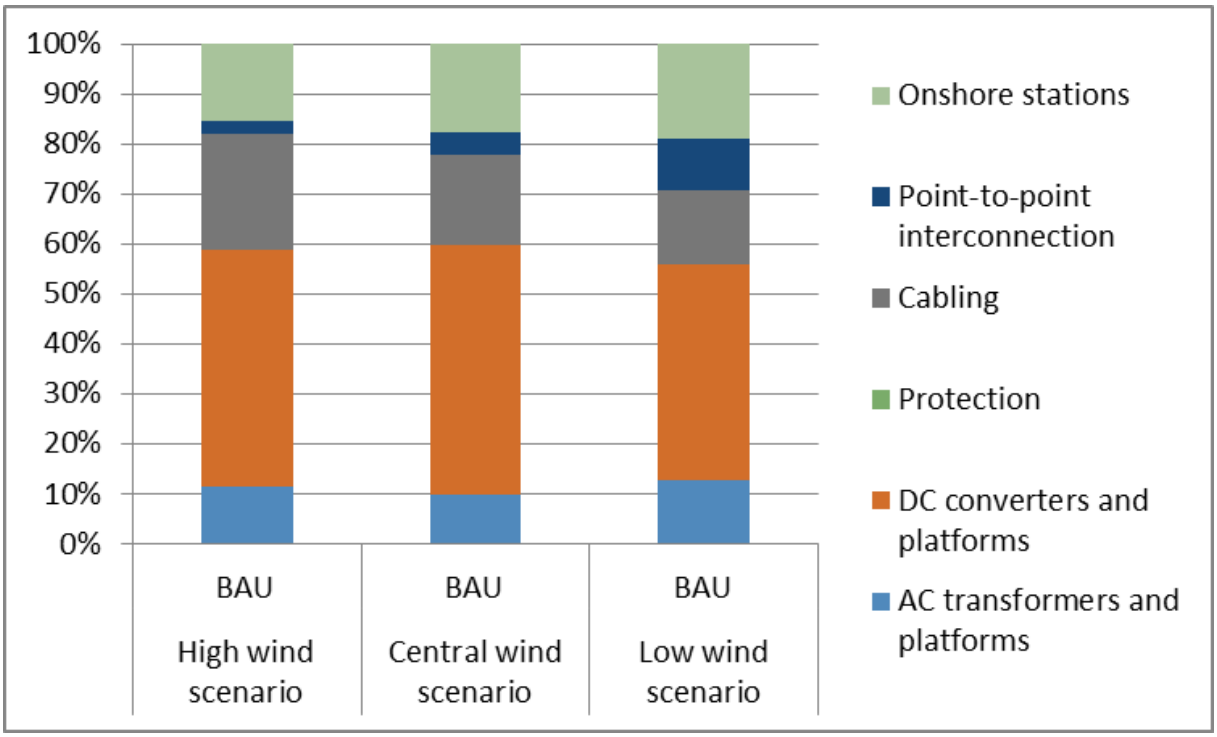
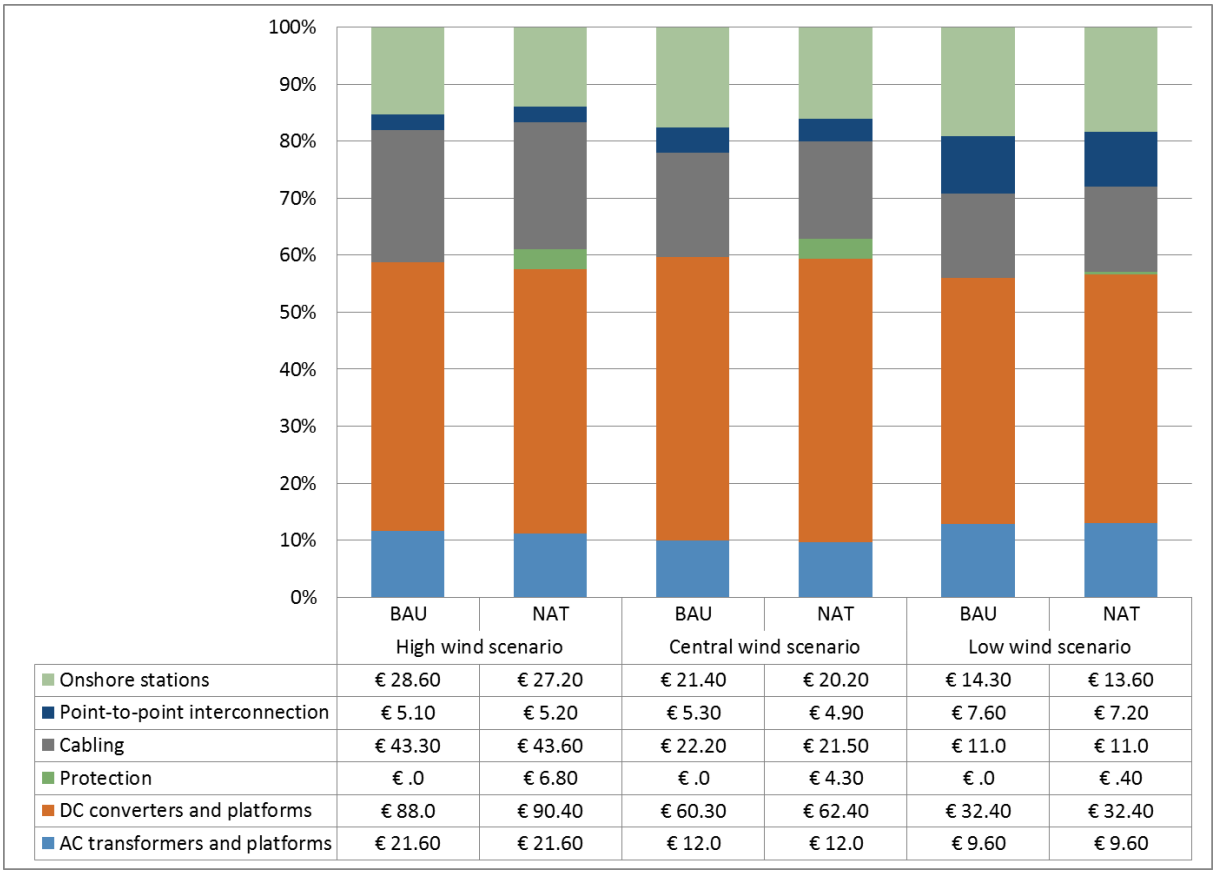


Figure 6-4 - Breakdown of cost of components in bn€ and relative to its total in the BAU concept.

6.4.3 COSTS OF NATIONAL DISTRIBUTED HUBS

The majority of the costs in the cumulative CAPEX over the whole period for the NAT concept can be found in the offshore DC stations, just as in the BAU concept. This is shown in Figure 6-5 below, where again the total CAPEX is presented for each scenario as well as the change for the category compared to BAU. The other categories also remain similar in size, with additional costs found in the extension of the DC platform and the DCCBs for meshing, both categorised under protection. The protection costs decline when there is lower meshing, which is in parallel with the wind capacity installed. Noteworthy is also the costs for AC components, which are exactly equal to that of the BAU concept. This is due to the fact that the OWFs and the DC stations are at exactly the same location and thus the AC connection of the OWFs to those DC stations is the same. The cost of cabling is similar to the BAU concept, which can be attributed to the meshing of the grid as well as relaxation of the cluster constraint, as described in Section 5.3.1.1. Where OWFs were clustered to supersede the critical size, the model often chose for a more optimal size of cabling to shore than would logically be constructed. For example, two OWFs in the Dutch EEZ of ~1500 MW are connected with a 2000 and 1000 MW cable to shore. In order to realistically represent these OWFs, a connection as described in D12.1 is applied, where a DC cable interconnects the clusters. This carries additional costs for cabling, but only in the High wind scenario, where this relaxed clustering method is carried out. Additionally, the DC stations are slightly oversized because of meshing as well as this relaxation of the clusters. This means slightly higher costs for DC stations as well. This modelling step therefore clouds the analysis of these concepts slightly. In the Central and Low wind scenarios, however, there is a reduction in cable costs compared to BAU, although not significant enough to offset the costs for protection and connection to a DC platform. This shows that when the relaxation method is not applied, meshing is proven to be financially attractive in specific cases, where the reduction of cable length is significant enough to offset the costs for protection.

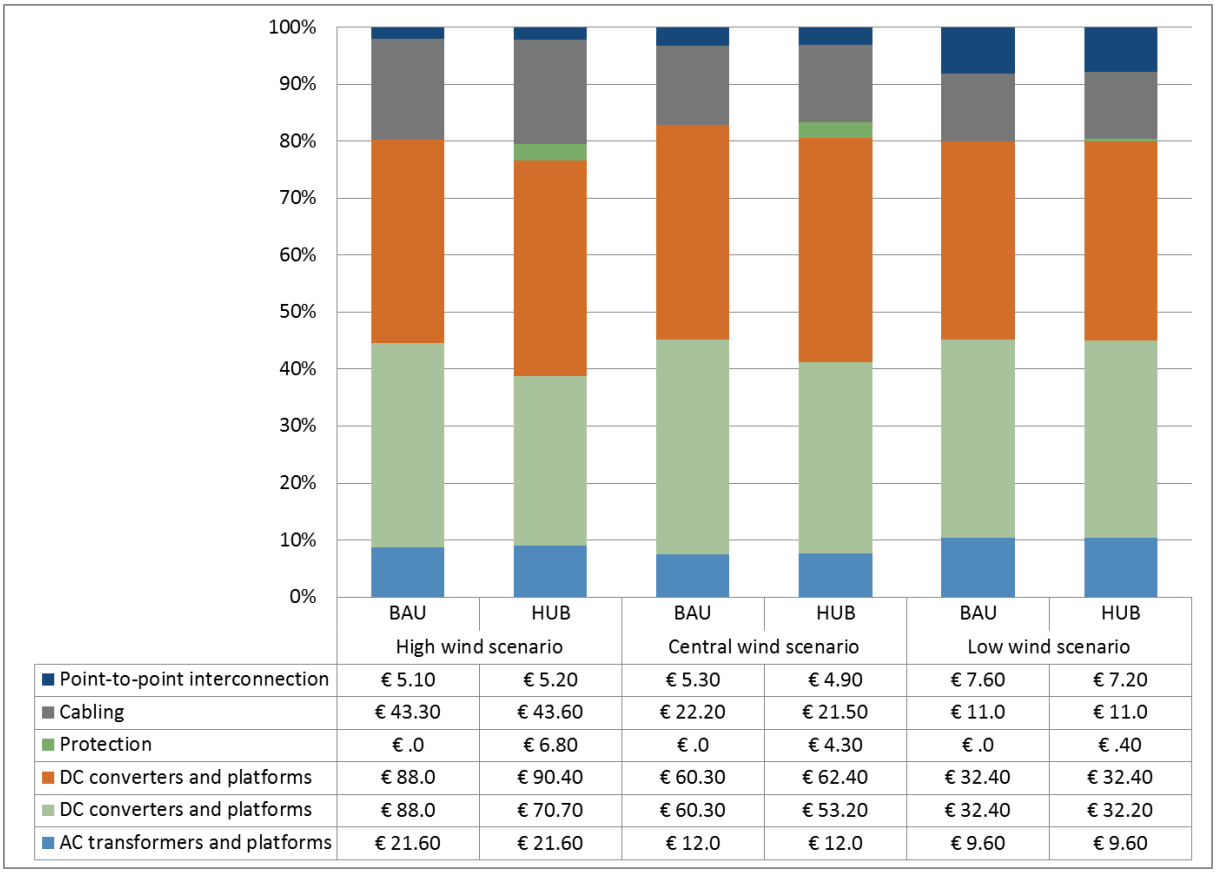


	BAU	NAT	BAU	NAT	BAU	NAT
	High wind scenario		Central wind scenario		Low wind scenario	
Onshore stations	€ 28.60	€ 27.20	€ 21.40	€ 20.20	€ 14.30	€ 13.60
Point-to-point interconnection	€ 5.10	€ 5.20	€ 5.30	€ 4.90	€ 7.60	€ 7.20
Cabling	€ 43.30	€ 43.60	€ 22.20	€ 21.50	€ 11.0	€ 11.0
Protection	€ .0	€ 6.80	€ .0	€ 4.30	€ .0	€ .40
DC converters and platforms	€ 88.0	€ 90.40	€ 60.30	€ 62.40	€ 32.40	€ 32.40
AC transformers and platforms	€ 21.60	€ 21.60	€ 12.0	€ 12.0	€ 9.60	€ 9.60

Figure 6-5 - Breakdown of cost of components in bn€ and relative to its total and to BAU in the NAT concept.

6.4.4 COSTS OF EUROPEAN CENTRALISED HUBS

A cost breakdown in the cumulative CAPEX over the whole period for the HUB concept can be found in Figure 6-6. As a large portion of the offshore DC platforms are replaced by islands, the large share of the DC platforms is no longer prevalent in the HUB concept. The total share of the DC stations is 39 - 48 %, down from ~50 % in the BAU concept. The AC components are of a larger influence in this concept than in the BAU concept, as the distance to a DC converter has changed. This is due to the locations of the island, which are more centralised and therefore, on average, further away than the DC platforms. The increase in AC component is offset by the decrease in costs for the converter sub-structures, except for the Low wind scenario. Several hybrid structures also emerge in the HUB concept, for which a protection system must be applied. The costs for his protection system remain quite low, however. In general, the costs of other categories are similar to that in the BAU concept. The HUB concept therefore illustrates well the application of islands in a densely populated area, where several OWFs could be connected to a single island. The Low wind scenario also proves that this only works for areas of a particular high density and that only a few OWFs do not offset the costs of the construction of an island, as the increase in AC component costs are higher than the decrease in DC station costs.

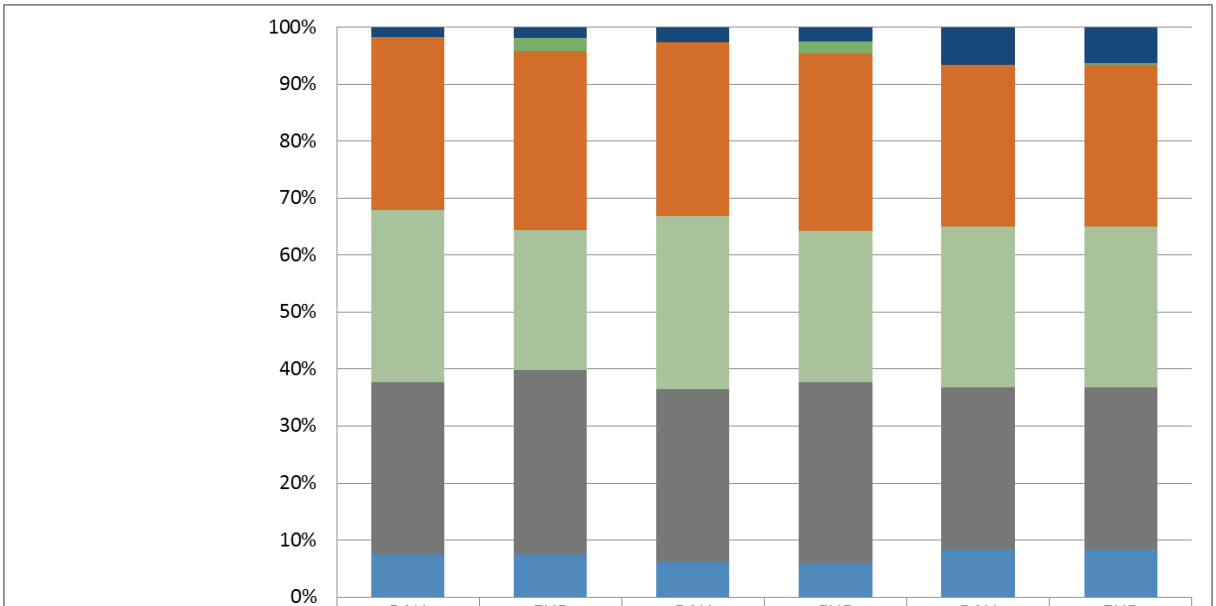


	BAU	HUB	BAU	HUB	BAU	HUB
	High wind scenario		Central wind scenario		Low wind scenario	
Point-to-point interconnection	€ 5.10	€ 5.20	€ 5.30	€ 4.90	€ 7.60	€ 7.20
Cabling	€ 43.30	€ 43.60	€ 22.20	€ 21.50	€ 11.0	€ 11.0
Protection	€ .0	€ 6.80	€ .0	€ 4.30	€ .0	€ .40
DC converters and platforms	€ 88.0	€ 90.40	€ 60.30	€ 62.40	€ 32.40	€ 32.40
DC converters and platforms	€ 88.0	€ 70.70	€ 60.30	€ 53.20	€ 32.40	€ 32.20
AC transformers and platforms	€ 21.60	€ 21.60	€ 12.0	€ 12.0	€ 9.60	€ 9.60

Figure 6-6 - Breakdown of cost of components in bn€ and relative to its total and to BAU in the HUB concept.

6.4.5 COSTS OF EUROPEAN DISTRIBUTED HUBS

For the EUR concept, a similar storyline holds as for the NAT concept. Due to the optimisation, the overall cable length is further optimised, but is offset by the clustering of OWFs. This is reflected in the cumulative CAPEX over the whole period for this category, as is presented in Figure 6-7. As was seen before in the BAU and NAT concepts, the largest share is still attributed to DC platforms at around 50 % of costs. The additional costs for protection and DC stations constitute the higher costs for the EUR concept compared to the BAU concept, as was also seen in the NAT concept. Again, the cabling is more expensive in the EUR concept due to the relaxed clustering method.



	BAU	EUR	BAU	EUR	BAU	EUR
	High wind scenario		Central wind scenario		Low wind scenario	
Point-to-point interconnection	€ 5.10	€ 5.20	€ 5.30	€ 4.90	€ 7.60	€ 7.20
Protection	€ .0	€ 6.80	€ .0	€ 4.30	€ .0	€ .40
DC converters and platforms	€ 88.0	€ 90.40	€ 60.30	€ 62.40	€ 32.40	€ 32.40
DC converters and platforms	€ 88.0	€ 70.70	€ 60.30	€ 53.20	€ 32.40	€ 32.20
DC converters and platforms	€ 88.0	€ 92.70	€ 60.30	€ 63.30	€ 32.40	€ 32.40
AC transformers and platforms	€ 21.60	€ 21.60	€ 12.0	€ 12.0	€ 9.60	€ 9.60

Figure 6-7 - Breakdown of cost of components in bn€ and relative to its total and to BAU in the EUR concept.

6.5 VALIDATION OF RESULTS

6.5.1 ANALYSIS OF EXISTING PROJECTS

In order to validate the approach taken in the costing model, an analysis of existing DC projects is made. The purpose of this analysis is to validate the choices that are made in the costing model to existing projects. Currently – in 2020 –, there are nine OWFs in the North Seas that are DC connected to shore, all of which in Germany. Two more DC projects are planned to be commissioned in Germany by 2023 and 2024 and another in the Netherlands, by 2027. An overview of these projects is made in Table 6-7, with their commissioning date, generation rating and length of connecting DC cables. For each of the projects, the rating and voltage output of the substation that would be constructed according to the costing model in PROMOTioN (P) and the substation that is actually constructed (A) is shown as well. From these columns it can be seen that most substations according to the costing model would match the actual constructed substation quite well. There are three exceptions to this. First, the BorWin1 OWF is a small windfarm which is connected through an equally small substation in reality. In the model the smallest DC substation option is 700 MW, which is why this substation would be constructed. In the topologies there are a few cases of OWFs that are smaller than 600 MW and thus have a significant overcapacity in their substation. As there are only a few cases, this has only a minor impact on the final cost figure. Second, the DolWin2 OWF is slightly over 916 MW, which in the costing model would require a 1000 MW, 525 kV substation. However, in reality a 320 kV substation is sufficient. For a 320 kV substation the choice of 900 MW would be too small in the model, while a rating of 1200 MW is too large. A choice of 1000 MW would fit better, but this option is 525 kV. In the model the OWF are generally well sized to fit the rating of available converters but there are certainly cases where there is some overcapacity of the substation compared to the OWF generation. The steps in costs for converters may be quite large, i.e. a few tens of million Euros, but in

the overall picture of ~200 bn€ in costs these cases will not be significant. Finally, the input voltage into the actual substation is given as well, where a definite progress in technology can be observed. Where the input in all existing windfarms is almost always 155 kV, the input in the latest planned OWFs drop to 66 kV. This means there is no requirement for an offshore transformer to transform the output voltage of the OWF to ~150kV. Although no data was found on the distance between the OWF and the substation, it has been noted that moving towards a 66 kV connection to the substation is only a recent innovation. It can therefore be assumed that transforming the input voltage used to be a standard step in the connection of the OWF, independent of the distance. The application of 66kV input voltage into the model therefore shows that the costing model is up-to-date with the current developments of technologies. All in all, the decision tree in Section 6.3.3 seems to allow for a correct choice of components and thus cost estimation of the topologies once compared with existing OWFs. It is also noted however that the analysis of the existing projects shows a significant progress in technologies in the span of ~15 years. This topic is covered in the discussion in Section 9.4.

Table 6-7 – Characteristics of existing and upcoming DC connected windfarms in Germany and the Netherlands.

NAME	DATE	RATING	LENGTH	SUBSTATION (P)		SUBSTATION (A)		INPUT	SOURCE
BorWin1, DE	2010	400 MW	200 km	700 MW	320 kV	400 MW	150 kV	170 kV	[23]
BorWin2, DE	2015	800 MW	200 km	900 MW	320 kV	800 MW	300 kV	155 kV	[24]
DolWin1, DE	2015	800 MW	165 km	900 MW	320 kV	800 MW	320 kV	155 kV	[25]
HelWin1, DE	2015	576 MW	130 km	700 MW	320 kV	576 MW	250 kV	155 kV	[26]
HelWin2, DE	2015	690 MW	130 km	700 MW	320 kV	690 MW	320 kV	155 kV	[27]
SylWin1, DE	2015	864 MW	205 km	900 MW	320 kV	864 MW	320 kV	155 kV	[28]
DolWin2, DE	2016	916 MW	135 km	1000 MW	525 kV	916 MW	320 kV	155 kV	[29]
DolWin3, DE	2018	900 MW	160 km	900 MW	320 kV	900 MW	320 kV	155 kV	[30]
BorWin3, DE	2019	900 MW	160 km	900 MW	320 kV	900 MW	320 kV	?	[31]
DolWin6, DE	2023	900 MW	90 km	900 MW	320 kV	900 MW	320 kV	155 kV	[32]
DolWin5, DE	2024	900 MW	130 km	900 MW	320 kV	900 MW	320 kV	66 kV	[33]
Ijmuiden Ver Alpha, NL	2027	2 GW	<100 km	2 GW	525 kV	2 GW	525 kV	66 kV	[34]

6.5.2 SENSITIVITY TO INPUT FACTORS

A change in input factors is made in order to evaluate the sensitivity of the cumulative CAPEX and OPEX figures by 2050. For the sake of clarity, the sensitivity is only applied to the results of the High wind scenario. An overview is presented in Figure 6-8. First, the minimum and maximum value of the cost of each component is applied in the model in order to evaluate the uncertainty that is already present in the cost values (indicated as *Range of uncertainty*). Noticeable here is that the calculated figures of the NAT and EUR topologies, using the average value for the cost of components, are within the upper range of uncertainty of the BAU concept. The uncertainty on the cost of components is not only dependent on the immaturity of the technologies but also on factors such as converter configurations for converters or water depth and structural weather conditions for platforms. These factors are not taken into account in the cost calculation but could alter the proportion of NAT and EUR to BAU, as there is only a marginal difference in costs. Additionally, the HUB concept shows a little more robustness to the input of cost data as significantly fewer platforms, with a high uncertainty range, are present in the topology. The highest value of HUB costs is also close to but still lower than the average value of the BAU concept, again

stressing the financial benefit of using artificial islands as support structures over the use of DC platforms in places of high wind generation density.

The sensitivity of the outcomes to four other factors are also analysed, namely the 66 kV AC cabling, the protection scheme, the cable connection cost to a platform and the cost of islands. Disallowing 66 kV AC cabling under 25 km (indicated as *66kV*) entails the use of 150 kV platforms and converters from the base of the OWF to the DC converter in all cases. It can be seen in Figure 6-8 that the change of 66 kV cabling to 150 kV cabling increases the total cost figure, but its overall impact remains marginal. Applying a partial selective protection scheme (indicated as *protection*) rather than a fully selective protection scheme does not impact the total cost figure much, which is also the case for having a 90 % decrease in cost for cable connection to a platform (indicated as *cable*). This shows again the minor impact of these factors on the overall cost figure. The sensitivity analysis of the island cost (indicated as *island*) has been done by assuming the constant cost figure to be applicable to a 10 GW island. This island is imagined to be a truncated cone, with its top having a power density of 8 m^2/ MW[29]. The radius of the base of the island is assumed to be three times the water depth, which is assumed to be 40 meters. With these factors the volume of the 10 GW can be calculated, with which the costs per m^3 for an island can be calculated. This value is assumed to be constant, which allows to calculate the costs of other islands based on their hosting capacity. This method allows for an estimation of the costs of an island without assuming a linear correlation between hosting capacity and costs. As almost all islands in the cost calculation are larger than 10 GW, the cumulative costs increase for the HUB concept, with three out of the six islands almost doubling in costs. However, this has only a marginal impact on the overall costs, showing that the applicability of artificial islands is not so much dependent on their costs but rather on their location with respect to wind energy generation, as was shown in the Low wind scenario.

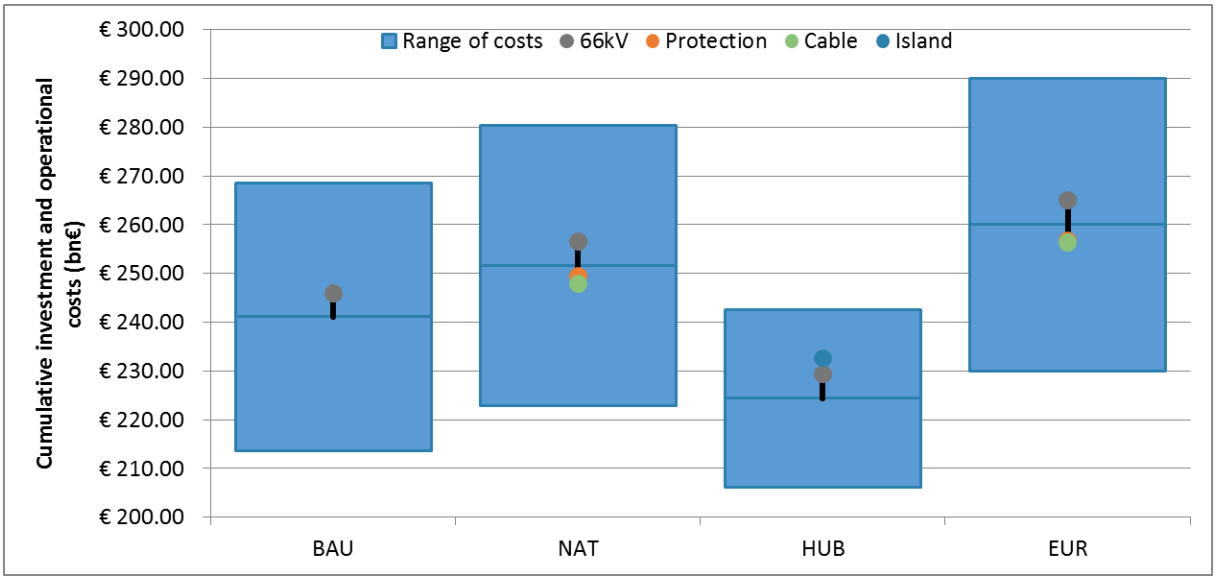


Figure 6-8 - Sensitivity of the outcome of the analysis to input factors.

6.6 CONCLUSION

Using the current assumptions, this preliminary analysis indicates that the reduction in cable length due to meshing will not offset the additional costs for cable connections and protection. The reasons for this are twofold.

[29] From DNV GL internal sources a value of 11 m^2/ MW was obtained for onshore converter stations while 5 m^2/ MW is used for offshore converter stations. An artificial island is assumed to not require the highly optimised power density of an offshore platform, but also to optimise such that it requires less space than onshore converter stations. An average of the two values is therefore assumed.

First, meshing a grid is mostly beneficial to create alternative pathways in cases of failures, but the analysis considers all cables to be in bipole configuration. A bipole configuration encompasses a natural redundancy in each connection and therefore decreases the need for meshing. Additionally, the cables used in the modelling have a very low outage rate and are sized to be equal or lower to the maximum reference incident of the onshore grid they are connected to. This means for evacuation only there is no real need for the meshing of the grid. Secondly, the point-to-point configuration in the BAU concept is already modelled quite optimally, where multiple windfarms are modelled and combined to reach a critical size of 2000 MW. Connecting windfarms to a larger, single cable connection to shore is a proven concept, so far being used for example in Germany and planned in the Netherlands and Belgium. Consequently, when the same windfarms are connected in another concept, this leaves little capacity on an evacuation cable to evacuate additional wind energy from yet another windfarm. The result is that many point-to-point connections in the topologies are modelled and few meshed structures are created. The decrease in cable length and costs is therefore minor, where the additional costs for cable connection on a platform as well as the protection system offsets these savings. A true point-to-point topology, however, would not combine windfarms to bring these to shore, which would result in a far higher cable length in BAU and thus a higher comparative reduction in NAT or EUR. The predominance of point-to-point connections masks the benefits created by meshing in the full picture. Focus on sections of the grid does generate material savings.

Many uncertainties are modelled that could influence the outcome of the analysis and therefore the attractiveness of the NAT and EUR concept:

1. The cost uncertainty in figures shows that the calculated figures of the meshed topologies are within the range of uncertainty of the BAU concept. The range of uncertainty is not only dependent on the immaturity of the technologies but also on factors such as converter configurations for converters or water depth and structural weather conditions for platforms. These factors are not taken into account in the cost calculation but could alter the proportion of NAT, HUB and EUR to BAU, as there is only a marginal difference in costs. The HUB concept shows a little more robustness to the input of cost data as significantly fewer platforms, with a high uncertainty range, are modelled.
2. A sensitivity analysis in Section 5.5 shows that changes to the topology input may largely influence the cable length in the concepts. Especially the NAT, HUB and EUR concepts may have a significant reduction in cable length (between 20 – 40 %) when the topologies are modelled with 4 GW cables and no onshore capacity constraint. This opposed to the BAU concept, which may reduce its cable length by ~10%. This shows that the BAU concept is close to its optimal cable length, while the other concepts may still be heavily influenced by innovations in the technologies.
3. The investment for the protection system used in the analysis is 8,7% which may be a high estimate given the range resulting from analysis. Additionally, the cost of an extra cable connection to a platform is purposely assumed to be relatively high, as there are still many uncertainties associated with these costs. These costs may therefore be much more reduced as technologies evolve.

Even with the current assumptions, the three major grid configuration options are always present in the (meshed) topologies and therefore all may be considered viable options.

First, most meshing can be found in interconnecting structures, where two close-by windfarms are connected so that their evacuation cables may be used to transport energy in times of low wind. In the topologies, it is seen most direct interconnector cables in BAU are replaced by these relatively low-cost structures in NAT and EUR.

Second, where generation is concentrated, a significant cost saving might be achieved. This is especially apparent where the HUB concept is applied. Aggregating the generation on large artificial islands replaces many expensive platforms, thereby significantly reducing costs. This is, however, as the Low wind scenario shows, not always the case for artificial islands below 10 GW. For such islands, it is important that OWFs that are within an optimal distance to the islands are connected to the island only. This optimal distance, as was found out in the cost calculation, is not fixed. When an OWF is positioned between the island and the onshore connection point, this optimal distance to the island is lower than when the OWF has an island located between it and the onshore connection point. This is not taken into account in the topology generation.

Third, point-to-point structures are prevalent in all topologies. Although relatively straightforward structures, connecting offshore windfarms to a largely sized cable is seen as an efficient way to connect offshore windfarms to shore, especially with the technology available to date.

7 BENEFITS OF THE TOPOLOGIES

7.1 SUMMARY OF THE CHAPTER

In order to compare and evaluate the topologies and operational strategies, a benefit analysis has been developed to evaluate the certain advantages and give a recommendation with which concepts to proceed. This benefit analysis is a system-wide study of the European electricity system in which the topologies develop as was described in the previous Chapters. Through this study several of the benefit KPIs of the CBA methodology can be quantified. The Chapter gives an overview of all relevant system components and their modelling within the benefit analysis. As the benefit analysis foundation is a load flow calculation, the whole examined system has to be represented as a steady-state model. The generation units base modelling is similar between all primary fuel types, some of them have additional constraints to get a more realistic representation. Furthermore, the load, converter stations and cables are introduced as well.

Afterwards the transfer of these models into an appropriate optimisation method is discussed, as well as a schematic overview of the whole simulation process given and explained. As a last step, the assessment of potential benefits is detailed with the technical calculation basis and needed input data to determine results.

The results per KPI are given for each of the concepts. Although benefits can be observed in all concepts, the biggest for all quantified benefits can be found in the NAT concept, followed by the EUR and HUB concept. As one of the main conclusions of the analysis is that the ability of the system to fully utilise its potential lacks. The installed capacity of hydro-pump storage is not sufficient anymore as the only storage option available and thus more flexible options should be considered. These could be, with the current research status in mind, either battery storage or power-to-X. Raising the capacity on strategic interconnectors could also be possibility, such as between Germany, Austria and Switzerland or Germany, Denmark and Norway. Less congestion on these interconnectors could mean a better utilization of hydro generation, but an overall view of the onshore system is needed to avoid bottlenecks within the meshed system.

The Chapter also highlights non-quantified benefits of the meshed concepts as opposed to the BAU concept. Additionally, the social KPIs are discussed, where a comparison is made between the concepts that apply only HVDC platforms and the HUB concept, which applies artificial islands. From these analyses the benefits of the concepts do not differ a lot, with some concepts scoring better on one KPI and scoring worse on another.

7.2 INTRODUCTION

The aforementioned four developed concepts were determined with different frameworks and resulting barriers in mind. Each concept is an optimal solution within their respective limitations. In order to compare and evaluate the different topologies of these concepts, a benefit analysis has been developed to evaluate the certain advantages and give a recommendation with which concepts to proceed. This benefit analysis is a system-wide study of the European electricity system in which the topologies develop as was described in the previous chapters. Through this study several of the benefit KPIs of the CBA methodology can be quantified. However, not all KPIs are possible to quantify and some are even deemed unnecessary to quantify. Therefore, in the following Section, the benefit analysis is firstly detailed, displaying results of the quantification of several KPIs. Afterwards, the other benefit KPIs are described qualitatively. Which KPI is described quantitatively or qualitatively can be found in Table 7-1 below. The residual impacts, which may well also be costs, are also described in this section.

In the following sections, first the benefit analysis is explained in detail, starting with the modelling of the European transmission system and followed by detailed models of system components. Afterwards the structure of the optimisation method and result evaluation is presented. This completes the quantification of the benefits. Then, this Chapter completes with a qualitative study of the remaining KPIs.

Table 7-1 - The KPIs and the method of describing them.

#	NAME	METHOD	COMMENT
B1	Socio Economic Welfare	Quantitative	This KPI represents the flexible generation costs and will be scored in €.
B2	RES Integration	Quantitative	As the amount of RES integration is the same throughout the concepts, this KPI is scored on the avoided RES spillage in MWh.
B3	CO_2 Variations	Quantitative	This KPI is scored in t
B4	Societal Well-being	Qualitative	The task of scoring this KPI is tedious and may lead to double counting of benefits. This benefit is therefore not evaluated.
B5	Grid losses	Quantitative	Analysis of DC grid losses only, in GWh
B6	Security of Supply – Adequacy	Quantitative	Calculation of Loss of Load Expectation, in GWh and h/a.
B7	Security of Supply – Flexibility	Qualitative	
B8	Security of Supply – Security	Qualitative	
B9	Security of Supply – Resilience	Qualitative	
S1	Environmental	Qualitative	
S2	Social	Qualitative	
S3	Other	Qualitative	

7.3 QUANTITATIVE ANALYSIS OF BENEFITS

7.3.1 SCOPE OF THE STUDY: RESEARCH ON EUROPEAN ELECTRICITY SUPPLY SYSTEM

For a full comprehensive study of the influence and therefore benefits of the developed HVDC offshore system on the existing European transmission and generation system a useful grid representation model is necessary. In an ideal scenario a full representation of the ENTSO-E transmission system with the available generation units would be used as the base for integrating the offshore topologies. This approach poses some problems:

1. The available ENTSO-E TYNDP 2018 transmission system is only available for one point in time. With the construction of an offshore grid, a joint expansion of the AC system is also necessary. Integrating an offshore topology beyond 2030 would probably lead to convergence problems during load flow calculations, as too much congestion on available lines and cables exist. As the AC system expansion plan is not part of the PROMOTioN project and would take too much time, a simplified node model for the AC system is used instead.
2. Specific generation unit data is not publicly available, only accumulated generation data per country and primary element. Therefore, only this accumulated generation data will be used together with the simplified AC node model and logical simplifications.

In summary, a European node model is used in which each market area of the ENTSO-E is represented by one node. This approach is in line with the development of the offshore topologies, with the exceptions that not only the North Seas adjacent states are portrayed, but also additional market zones in south and middle / east Europe.

To evaluate the offshore topologies and quantify the benefits of the different concepts, a simulation of a period over a longer timeframe is necessary. Finally, the benefit analysis simulates one whole year with a step size of one hour, which leads to 8760 system-use-cases within the optimisation. With that approach, seasonal variations of the generation can be considered and the analysis of the future energy sector with a high amount of RES could discover potential seasonal weaknesses.

The developed offshore topologies are represented in detail, only the determined offshore wind farms are not depicted as several single wind turbines, but as a summarised power injection instead.

7.3.2 MODELLING APPROACH AND VALUATION METHOD

This Section will give an overview of all relevant system components and their modelling within the benefit analysis. As the benefit analysis foundation is a load flow calculation, the whole examined system has to be represented as a steady-state model. The generation units base modelling is similar between all primary fuel types, some of them have additional constraints to get a more realistic representation. Furthermore, the load, converter stations and cables are introduced as well.

Afterwards the transfer of these models into an appropriate optimisation method is discussed, as well as a schematic overview of the whole simulation process given and explained. As a last step, the assessment of potential benefits is detailed with the technical calculation basis and needed input data to determine results.

7.3.2.1 SYSTEM COMPONENTS

7.3.2.1.1 GENERATION UNITS

The generation units as part of the degrees of freedom within the optimisation problem can be limited by technical restrictions. This includes the minimum and maximum output levels of active power ($P_{generation}$). Including the provision of reactive power is possible but not necessary for the basic node model of the European AC system. Modelling as conventional generation units include the ENTSO-E fuel types biofuel, gas, hard coal, lignite, nuclear, oil, other- and other non-RES. These generation units can be dispatched for each hour (*t*) of the simulated year and set to a value between the minimum active power and the specific installed capacity in that year for that country.

$$P_{min,\,generation} \leq P_{generation_t} \leq P_{max,\,generation} = P_{installed\ capacity} \tag{7-1}$$

Renewables (offshore/onshore wind, PV, Solar thermal) are always dispatched first during the simulation, as their marginal costs are the lowest of all generation units. An operation with the nominal installed power is not always possible, as the power output of these renewables is weather and time dependent. To simulate this behaviour, capacity factors are used. They represent the percentage of the nominal installed power that is available in a certain timeframe. The renewables can therefore operate in each simulated hour between a minimal active power value (which is zero in this case) and the time-specific maximum active power.

$$0 \leq P_{res_t} \leq P_{max,res_t} \tag{7-2}$$

Hydro-generation is supported in three variants taken from the ENTSO-E: hydro-pump-storage, hydro-reservoir and hydro-run generation. The first variant consists of two reservoirs with a certain height difference between them. To generate energy, water flows from the top reservoir to the lower one and drives a turbine. As the reservoirs only have a certain storage capacity, at one point in time water has to ascend from the lower to the top reservoir via pumps. To simulate hydro-pump-storage generation units, their turbine and pump are each modelled as a variable which are connected through several constraints and additional operational and decision variables within the linearized optimisation problem. The turbine (7-3) and pump (7-4) can operate between a minimum active power level and a maximal active power level, the latter one being country specific. It is not foreseen to operate the pumps and turbines of the generation unit at the same time. Binary variables (7-5) for the operating status are introduced and connected through constraint (7-6) to avoid simultaneous operation. A time-coupling constraint with the available storage capacity as upper and lower bounds ensures switches between turbine and pump operation.

$$P_{min,turbine} = 0 \leq P_{turbine} \leq b_t \cdot P_{max,\,turbine} \tag{7-3}$$

$$P_{min,pump} = 0 \leq P_{pump} \leq b_p \cdot P_{max,\,pump} \tag{7-4}$$

$$b_{turbine}, b_{pump} \in \{0,1\} \tag{7-5}$$

$$0 \leq b_{turbine} + b_{pump} \leq 1 \tag{7-6}$$

Hydro-reservoir units are classical dams with a reservoir, which is filled via a natural inflow. As this inflow is weather dependent and a weather simulation not available, a time-coupling constraint ensures that these units can only generate a certain amount of energy each month. The value is derived from the ENTSO-E Transparency platform and extrapolated with the installed hydro capacity of each simulated scenario year. By using monthly energy bounds, seasonal influences of the inflow can be modelled with sufficient accuracy.

The hydro-run units are modelled as a normal generation unit (see above). Derived from the ENTSO-E Transparency Platform are capacity factors for each hour and country. These are applied on the installed capacity per country. The result is the maximal generated power possible. By using capacity factor derived from historical data seasonal changes of the water level can be considered. Depending on the chosen year for the data, the influences of dry, wet or normal weather years can be simulated. It has to be noted, that the data taken from the ENTSO-E should be taken from the same year to ensure consistency.

7.3.2.1.2 LOADS

The aggregated loads of each European node are designed without a flexible component (demand side management). Therefore, the demand should equal the supplied energy at one node in each simulated hour. The supplied energy could come from generation units onshore or offshore via HVDC connections and from market trading via interconnectors between the country nodes. The balancing constraint (7-7) for each country *c* ensures

this behaviour during the simulation. The slack variable P_{slack_c} ensures that the equation is always solvable, even in hours without enough supply. By giving the slack variable a high cost coefficient, the usage is minimised. When used, the missing energy on that node is an output in the results as *Loss of Load Expectation* (LOLE).

$$\sum P_{generation,onshore_c} + \sum P_{conv,onshore_c} + \sum P_{trading_c} + P_{slack_c} = P_{load_c} \tag{7-7}$$

$$0 = P_{slack_c} = \infty \tag{7-8}$$

7.3.2.1.3 CONVERTER TECHNOLOGY

Converters between the HVAC and HVDC system are modelled as injections into that specific system (Figure 7-1). The technical restrictions are therefore similar to generation units, with a minimum and maximum output level of active power.

$$P_{min,conv_i} \leq P_{conv_i} \leq P_{max,conv_i} \tag{7-9}$$

The active power injection of the offshore converters, connecting an OWF to the offshore HVDC system, is linked to the active power output of the OWF. That way the setpoints of the converter changes accordingly with the OWF it connects. When several wind farms are connected through one converter, they are included in the constraint as well.

$$P_{res,offshore} = -P_{conv_i} \tag{7-10}$$

7.3.2.1.4 HVDC-CABLES

The DC cables technical restrictions are depicted by their thermal design, which means limitations of the transferred power or current. The maximum allowed current $I_{branch,DC_{ij,max}}$ between the two nodes *i* and *j* without overloading the cable could be higher for a short period of time, which leads to $I^a_{branch,DC_{ij,max}}$ for short outage situations.

$$I_{branch,DC_{ij,min}} \leq I_{branch,DC_{ij}} \leq I_{branch,DC_{ij,max}} \tag{7-11}$$

$$I^a_{branch,DC_{ij,min}} \leq I^a_{branch,DC_{ij}} \leq I^a_{branch,DC_{ij,max}} \tag{7-12}$$

$$I_{branch,DC_{ij,min}} = -I_{branch,DC_{ij,max}} \tag{7-13}$$

Connections are modelled as bipolar. This has advantages in outage situations, as not the full transfer capacity of a connection fails. A failure on one cable leads to a remaining transfer capacity of 50 % nominal transfer capacity.

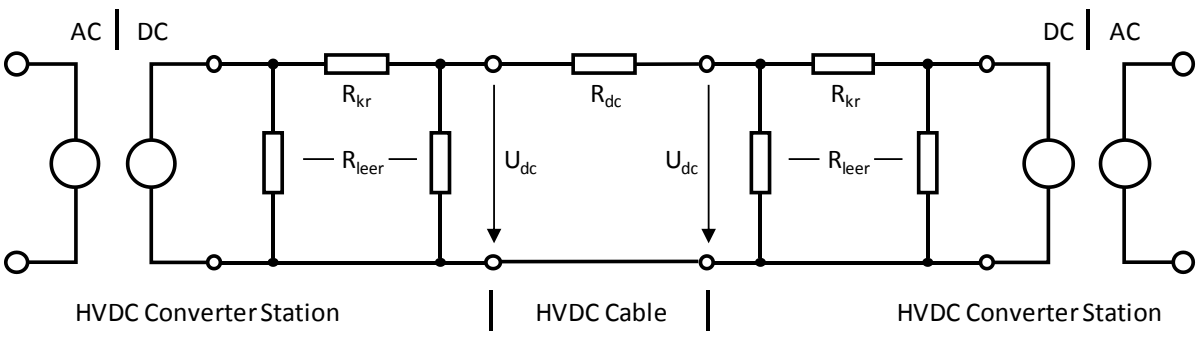


Figure 7-1 - Model of converter station and HVDC cable.

7.3.2.1.5 NET TRANSFER CAPACITY

AC-connections between the country nodes are not modelled in detail as a line or cable but considered as input data in form of available NTC. NTCs are determined bilaterally between two market areas without considering congestion induced by other interconnections. As no detailed AC onshore grid exists in the simulation, this approach is applicable. As the NTC between two market areas can be different depending on the direction, an upper and a lower limit exists.

$$-NTC_{B\rightarrow A} \leq P_{A\leftrightarrow B} \leq NTC_{A\rightarrow B} \tag{7-14}$$

7.3.2.2 OPTIMISATION METHOD

As discussed in the previous Section, the variables in the optimisation problem are all linear or binary. Therefore, the application of a mixed-integer linear programming (MILP) makes sense. Several ways exist to solve these problems, exact algorithms or heuristic methods. As the complexity of the optimisation problem is manageable and enough computing power available, an exact solver is recommendable. To achieve a fast and reliable solution, an external solver module is used. To use this solver, the optimisation problem has to be formulated:

$$min\, z = \vec{c}^{\,T} \cdot \vec{x} \tag{7-15}$$

$$\vec{b}_l \leq \boldsymbol{A} \cdot \vec{x} \leq \vec{b}_u \tag{7-16}$$

$$\vec{x}_l \leq \vec{x} \leq \vec{x}_u \tag{7-17}$$

The objective function (7-15) contains the relevant variables introduced in the section “system components” with their cost coefficients. These cost coefficients are derived from the marginal costs for each generation unit and fuel type specific. Each scenario and scenario year have specific marginal costs, as different CO_2 costs are taken as a basis. This results in a minimisation of the European generation costs, as the generation units are picked on a basis of a Merit Order curve. Generation units with high marginal costs will be picked last, when energy trading with cheaper neighbouring market areas is not sufficient enough to meet the demand.

Some variables, for example converter stations, have very small cost coefficients even when changing their setpoints does not produce costs in reality. This is necessary to avoid unnecessary changing of these setpoints which could result in loop flows on some parts of the system.

The constraints (7-16) in the formulated optimisation problem are the previous introduced operational constraints from “system components” and additional constraints with slack variables that secure a realistic result. In this case, the limits are not modelled as hard constraints, but can be violated with the help of those slack variables that should have very high penalty costs compared to the other penalty cost in terms of the objective function. These surplus variables are always non-negative and usually have no upper bound.

These are needed, as in real transmission grid operation it cannot be guaranteed that the transmission grid can always be operated (N-1)-secure. This can lead to infeasible optimisation problems, as it might be impossible to fulfil individual constraints. To deal with the problem of infeasible constraints, slack variables are introduced as additional degrees of freedom. For any network component violating any constraint prior to the optimisation procedure, a slack variable is introduced. This enables solving of the optimisation problem even if several physical constraints cannot be satisfied. Additionally, it penalises the remaining violations of constraints with high costs. Slack variables are required for branch current limits (for normal operation $\Delta I_{branch,slack}$ (7-18) and in contingency situations $\Delta I^{a}_{branch,slack}$ (7-19)).

Additionally, each market area has a slack variable within the balancing constraint to ensure feasibility of supply and demand. This is necessary, as the ENTSO-E input data could contain scenario timeframes, in which this generation-load balance is not guaranteed and therefore the LOLE has to be calculated (7.3.2.1.2).

$$0 \leq \Delta I_{branch,slack} < \infty \tag{7-18}$$

$$0 \leq \Delta I^{a}_{branch,slack} < \infty \tag{7-19}$$

$$I_{branch,\,DC_{ij}} \leq I_{branch,\,DC_{ij,\,max}} + \Delta I_{branch,DC,slack} \tag{7-20}$$

$$I^{a}_{branch,DC_{ij}} \leq I^{a}_{branch,DC_{ij,max}} + \Delta I^{a}_{branch,DC,slack} \tag{7-21}$$

Finally, all the variables and constraints are structured into the optimisation problem (Figure 7-2) and transferred to the MILP solver. The solver determines the cost optimal setpoints for the whole system in each simulated hour.

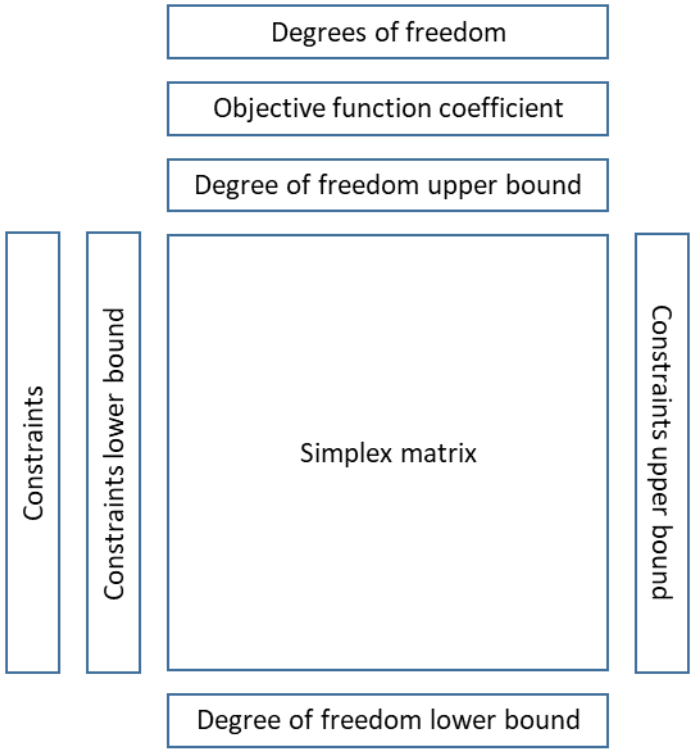


Figure 7-2 - Structure of the optimisation problem.

Key indicators

After each simulation the results are calculated and prepared for an easy-to-read output. The results contain, beside the setpoints of generators and converters, the loading on lines, voltage levels, CO_2 output of generation units, marginal costs per market area, the ENS and losses of the HVDC system. The main indicators to evaluate the concepts are the KPIs explained in more detail in the following. These KPIs resulting from the benefit simulation are:

- B1: Socio-economic welfare
- B2: RES integration
- B3: CO_2 variation

- B5: Grid losses

At the end of each KPIs theoretical background, a detailed explanation is given how these values are determined in the benefits analysis.

7.3.2.2.1 B1: SOCIO-ECONOMIC WELFARE

A MOG would potentially provide a large amount of interconnection capacity, connecting different European countries using power links with vastly higher capacities than available today. This will result in price convergence (through market coupling). This price convergence results in a direct effect on socio-economic welfare, which consists of the sum of consumer surplus, producer surplus, and – in the case of limited interconnection capacity – congestion rent. This is illustrated by Figure 7-3 below. The allocation of this socio-economic welfare to either consumers or producers is not relevant for the evaluation of total benefits, but could of course impact social acceptance or political support. The welfare gain of a project is then the socio-economic welfare, minus the cost of items considered in the CBA. This means that although any additional interconnection increases socio-economic welfare, the marginal gains of every additional interconnector may decrease. This could result in additional interconnector capacity not being worth the construction and/or operation costs (diminishing returns).

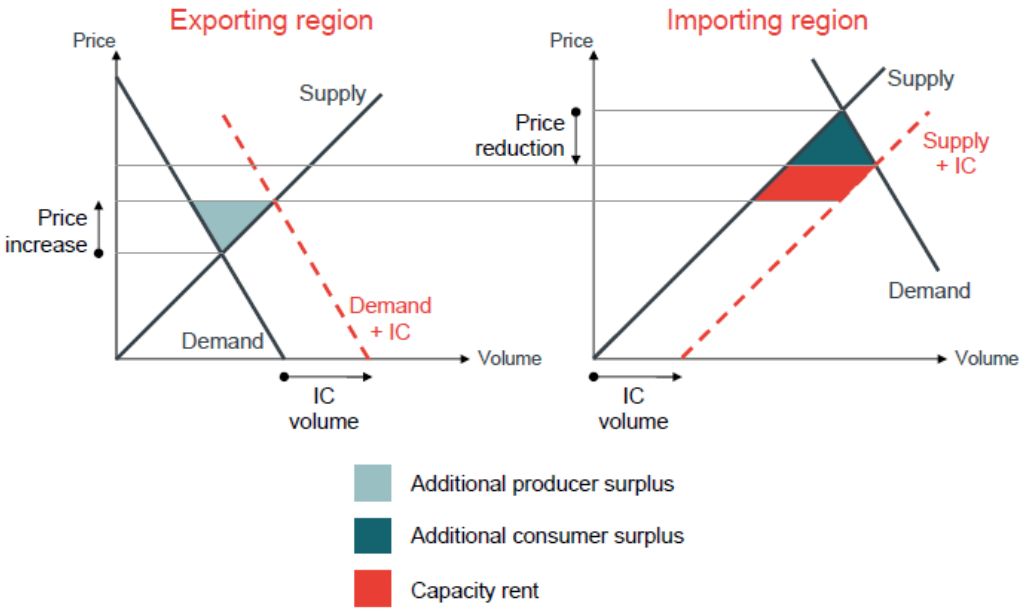


Figure 7-3 - Illustrative example of increase in socio-economic welfare due to an increase interconnection capacity, resulting in a producer surplus, consumer surplus and congestion (capacity) rent [35].

The concept of diminishing returns could be applicable in the development of an offshore grid: the optimal amount of interconnection capacity for socio-economic welfare may be different than the optimal amount of interconnection capacity for other benefits, such as renewable energy sources integration. In principle, these would lead to similar outcomes if the electricity market would function perfectly and all externalities (i.e. global warming due to CO_2-emissions) would be included within the market. However, the existing electricity market although it internalises many costs (such as emission, pollution security of supply, etc.), does not represent a perfect market since it does not include all of the externalities [36]. Therefore, other benefits than socio-economic welfare can be considered to be relevant to the development of an offshore grid as well.

The increase in market coupling due to an increase in interconnection would also reduce the quantity volatility in the market due to a larger volume of the market. This increase in interconnection will increase predictability of the market for the wind developers and therefore decrease their risk. Although some aspects of this benefit are

included in the direct socio-economic welfare calculations, the decrease in risk uncertainty due to a larger market can be considered to be a separate benefit. Decreasing risks has two major effects: wind farm developers can apply a smaller risk margin in the design of their business case and these developers can attract large amounts of capital at lower interest rates due to the lower uncertainty of the project. As a result, subsidy schemes become cheaper or superfluous and wind farm development is stimulated due to a decrease in barriers to development.

Furthermore, the electricity market considered actually consists of different markets. The aforementioned benefits apply to the commodity trading of electricity (all timescales). However, there is also a market for balancing services provided to the TSO. Due to an increasing share of variable renewable energy sources, balancing might become even more important in the future. Balancing of supply and demand can be achieved by increasing or decreasing the local supply and demand of electricity within one region (bidding zone), but also through increasing or decreasing the amount of energy transferred over interconnectors with other countries. Increasing the capacity of interconnection will result in more efficient international access to different suppliers of balancing services. This will result in a cost decrease for the relevant TSOs, which ultimately impact end-consumer transmission charges. As a result, prices between different bidding zones may converge generally and shorter or even real-time pricing may become more relevant.

Moreover, a MOG could result in less congestion management, which would result in lower redispatch costs. Congestion management is necessary if there are technical constraints to the desired flows resulting from the electricity market. Within one bidding zone ('market'), it is assumed that the grid is perfect ('copper plate') while matching demand and supply curves. This is, however, not always the reality. The transmission grid has technical constraints and the market optimisation does not take the geographical dimension of such grid constraints into consideration. If this leads to problematic situations, the TSO will require power generation to move from one area to another area within the same bidding zone. These 'redispatch' procedures come at high costs, since the original power supplier needs to be compensated for not being able to deliver power and another power supplier needs to be compensated for being required to deliver power. Preventing redispatch can thus save costs. If a grid is more interconnected, it resembles a copper plate more closely, resulting in less congestion management necessary and thus lower redispatch costs. This benefit is however strongly dependent on future bidding zone configurations.

The benefit simulation, as described before, considers no flexibility of the load. Because of this characteristic, the investigation and comparison of the socio-economic welfare uses the generation cost approach. In that approach the generation costs for the different offshore topologies for all involved and affected market areas are compared. Lower generation costs are preferred from a socio-economic standpoint, as these would translate to lower energy prices for the consumers in the simulated markets.

7.3.2.2.2 B2: RES INTEGRATION

A MOG could enable the enhanced integration of renewable energy sources into the power system. A first benefit with regards to the integration of RES is the provisioning of alternative pathing for wind evacuation. Even without applying a strict N-1 security criterion, a MOG would provide some redundancy for wind evacuation. As the availability of the offshore grid is not perfect, there is a significant benefit to having an alternative path for wind electricity available. This increases the amount of renewable energy integrated into the system, but also saves costs in compensation for downtime of the grid. The three-year (2015-2017) average offshore grid availability of TenneT was 94,21% compared to an onshore availability of 99,9987% [37]. This difference is due to the current absence of any redundancy in the offshore grid. Having a MOG could increase the redundancy and thus the net

availability of the offshore grid. Although this benefit alone may not be sizeable enough to justify the development of a MOG, it could still be a significant potential benefit to the development of the grid.

A second benefit with regards to the integration of RES is the improved access to storage due to more interconnection capacity. With an increasing share of variable renewable energy sources in the power system, the need for storage will most likely increase in the future. Storage can help balancing the variable production of renewable energy and help match this supply with consumer demand. As a MOG would increase the amount of available interconnection capacity, there will be improved access to storage. For example, the Netherlands already makes use of (virtual) storage of renewable energy by means of the NorNed interconnector to Norway [38]. This enables the Norwegian hydro power plants to act as a (virtual) storage for Dutch (wind) production. An increase in interconnector capacity would enable improved access to such storage facilities. This is valid regardless of the type of storage technology being used: more interconnection capacity would facilitate improved access and use of the storage facility in any case. This thus forms a second benefit of a MOG with respect to the integration of renewable energy sources.

Furthermore, a MOG could lead to more efficient use of wind production facilities as the curtailment of wind production could be decreased. Curtailment of (offshore) wind infeed is necessary when the grid is not capable of transporting all the intended electricity production to the load centres. For example, in 2016, 4.4% of German wind energy production was curtailed [39]. In Germany, offshore wind production is located in the Northern most part of the country whereas the Southern part represents the most important load centre. The transmission grid is not at all times capable of transmitting all wind power infeed from the North to the South. This results in the need for redispatch and curtailment: wind infeed is limited (curtailed) while conventional generation units in the south start producing electricity (redispatch). This results in alleviation of the grid constraints, but also in high redispatch costs and increased CO_2-emissions. A MOG could result in a decrease of curtailment and redispatch by having an overall higher capacity available. Assuming a slight overdesign in the offshore grid, offshore wind production could be exported directly to other countries in such a case, disburdening the onshore grid. This would lead to a more efficient use of wind production facilities as curtailment would not be necessary anymore. 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. As the rejection of power (curtailment) also leads to disturbances in the power quality, a decrease in curtailment would further improve the power quality offered in the system.

Fourthly, large amounts of wind power generation with strong reciprocal correlation can lead to marginal wind prices approaching 0 €/ MWh. This is due to the fact that wind power generation has low marginal costs, and at times of peak production a lot of wind power will suddenly become available. Of course, a marginal wind price approaching 0 €/ MWh is harmful for wind farm developers since it endangers their profit margins. A MOG would increase demand opportunity by having a larger market available for the accommodation of the wind power without having very strong reciprocal correlation between the wind parks. This is a contrast with the current – national – approach where the power generation of wind parks is usually quite strongly correlated. The improvement in demand opportunity would thus lead to less moments in time where the marginal wind infeed price approaches 0 €/ MWh. This both leads to better profit margins – an incentive for wind farm development – as well as to lower risks associated with wind farm development. Both effects would stimulate the integration of larger amounts of renewable energy sources into the power system.

Finally, a meshed gird could result in lower connection costs of OWFs. The MOG would enable a more coordinated approach to grid development and wind park connection, resulting in lower costs than a business as usual approach. This coordination refers to an international approach to spatial planning, assuming that countries

collectively decide on what is built where and when (both wind evacuation and interconnection capacity), including an optimisation on total system costs, synchronised timing of construction and proper incentives in place [40]. The cost-reduction potential is also a key argument used for the advancement of the North Sea Wind Power Hub: the development of such a hub would result in significantly lower grid connection costs than connecting each wind park individually to shore [41].

However, the cost-reduction potential depends heavily on the assumptions used, most importantly with respect to the dimensioning of the grid. If one assumes an equal amount of wind evacuation capacity and interconnector capacity for each different topology, a MOG topology in which wind evacuation transmission assets are combined with interconnection use will be cheaper than a pure radial solution with separate point-to-point interconnectors. This difference in costs is due to less transmission assets required, as illustrated in Figure 7-4 below.

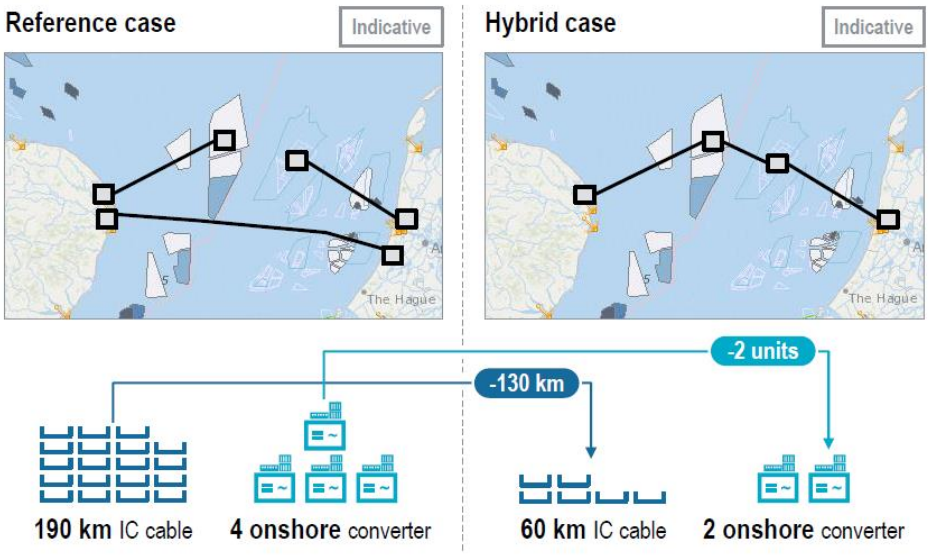


Figure 7-4 - Illustrative comparison between separate wind evacuation transmission assets and point-to-point interconnector compared to a hybrid approach, combining the two types of assets [42].

A grid topology in which wind evacuation transmission assets are combined with interconnection use will thus be cheaper. However, it is questionable whether this is a realistic assumption, since it is unlikely that an equal amount of interconnection capacity will be realised in such a scenario. Therefore, in a fair comparison, it is assumed that a MOG topology will not result in reduced costs but rather in more interconnection capacity available. This assumption is still based on the cost-reduction potential, but takes a different scenario as the reference. Thus, the working assumption is that for the same amount of costs, a MOG topology would offer more interconnection capacity than a pure radial (business-as-usual) topology would realise. Put differently; if part of the costs of the transmission assets is paid for by its interconnection use, this results in lower connection costs for offshore wind farms.

In short, the KPI analyses the curtailment of renewables in the power system [MWh/a] and includes the generation types of PV, wind onshore and offshore. Lower values are preferred.

With a high proportion of renewables in the system it could be necessary to upgrade existing interconnectors between market areas or build new ones. That would enable an exchange of energy at any time and could also better include storage facilities like hydro-pump-storage generation within the European power system.

Future research could also include additional flexibility in the form battery storage, demand side management or hydrogen production and their influence on curtailment.

7.3.2.2.3 B3: CO_2 VARIATION

A MOG could result in a net decrease of CO_2-emissions. The most significant impact on the amount of CO_2 (equivalent) greenhouse gas emissions will come from the development of renewable energy sources. However, within this project, the amount of renewable energy production is fixed within a scenario (205 GW of offshore wind in 2050 for the High wind scenario). Nonetheless, the total amount of CO_2-emissions emitted can still be dependent on the type of grid topology chosen to connect the windfarms.

Firstly, a MOG will result in an increase in the capacity credit of the offshore wind generation. The capacity credit refers to the total amount of *certain* wind generation. As wind power is a variable source, wind electricity output varies. The average of this varying wind output defines the capacity factor of a single wind turbine. The capacity credit is a measure of the total amount of generation power that is constantly produced by wind turbines in the system. This effectively entails the amount of conventional generation that can be completely displaced by wind generation. A MOG increases this capacity credit. This is due to 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 [43].

As wind production depends on wind speed – a local parameter – a larger geographical area thus entails a larger amount of wind power that is always available. This only holds, however, if this production can also be transmitted to the desired place: which is true in a MOG, but not in a radial grid topology. For example, if there is hardly any wind in the Dutch and German parts of the North Sea (assuming therefore high electricity price), but there is a large amount of offshore wind production in the seas surrounding Northern England (assuming therefore a low electricity price), a MOG would enable this wind production to be transmitted to the continental European system. For the continental European system, this would increase the total amount of wind production that is certain to be produced at all times, hence it increases the capacity factor. This displaces conventional (fossil fuel) power generation, resulting in lower CO_2-emissions.

Secondly, a MOG would increase coupling between different time zones, contributing to a better spread of total system peak load and hence a reduction of the maximum system peak load ('load-flattening'). The peak of the power demand usually occurs in the evening. If regions have different time zones, this usually means that the peak load of region A will not coincide with the peak load of region B. By interconnecting these time zones, the burden of satisfying these peak loads can be spread over multiple countries. By means of the interconnection, the peak load of the total system can be reduced. 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 entail a reduction in the amount of gas-generated power required, hence a decrease in CO_2-emissions. However, as a future energy system is envisaged to become more supply-driven rather than the current demand-driven approach, it is unclear to what extent this benefit will be a significant factor in 2050.

Thirdly, a MOG can contribute to a better utilization of the (potential of) different renewable energy sources within the European system. A better interconnected grid allows countries to focus on their specific comparative advantages with respect to different renewable energy sources. For example, a country that is very suitable for a high penetration of PV electricity generation could make use of wind energy generated in other countries throughout the night using a MOG (and vice versa). By doing so, the countries would not need to rely upon

conventional power plants to provide power throughout times in which their domestic renewable energy production supply is not large enough to satisfy demand. In doing so, a MOG decreases overall CO_2-emissions.

Finally, as a MOG leads to an increase in market integration, it could also lead to more efficient production plants. Less-efficient (in monetary terms) generation plants will be pushed out of the market by economic forces due to enhanced market integration. This move towards more efficient generation plants would also decrease the total amount of CO_2-emissions. This benefit only holds however if a sufficiently high price for CO_2-emissions is set (either via ETS-system or direct tax) and some generation would still be fossil fuel based. Only then would it result in less-efficient (in terms of CO_2-emissions) power generation plants being pushed out of the market.

In the benefit analysis, for each generation fuel type specific conversion values are given to calculate the CO_2 emissions (EM_G) in tonnes per year [t/a]. These conversion values are the standard efficiency in NCV terms (SE_G) [%] and the CO_2 emission factor (EF_G) [kg/Net GJ]. After the operational simulation determines the power dispatch of each generation unit, equation (7-22) is used to calculate the CO_2 emission for each hour.

$$P_G * \frac{1}{SE_G} * 3.6 * EF_G = EM_G \tag{7-22}$$

7.3.2.2.4 B5: GRID LOSSES

An important differentiator between different kinds of grid topologies is the quantity of grid losses associated with the grid topologies. Lowering the grid losses has been an important motivator for HVAC meshing: the grid losses for HVAC lines and cables are directly related to the square of the current transmitted over the connections. As meshing decreases the current strengths, it decreases grid losses. This benefit would in principle also apply to a HVDC MOG: meshing decreases the current strengths applied and decreasing these current strengths decreases the grid losses.

However, HVDC systems also require the use of converters. Although for longer distances – or underground or subsea systems – HVDC have lower losses than HVAC systems, HVDC systems still have losses. These losses occur in both the cables as well as the converters, where the latter are dominant in the amount of losses. HVDC meshing could reduce cable losses, but could also increase converter losses since more converters would be operating at power levels below their nominal capacity, which has a negative impact on their relative efficiency. The variation in grid losses thus depends on the relative predominance of cable losses versus converter losses and the relative efficiency of HVDC converters compared to their nominal power rating.

Nevertheless, an HVDC MOG could reduce grid losses in another way. The existence of a meshed HVDC grid could reduce grid losses in the onshore HVAC grid. This is heavily dependent on the specific interaction between the HVDC offshore and the HVAC onshore system. For example, HVDC facilitates better controllability of power flows which enables system operation strategies which optimise towards the lowest amount of grid losses possible. As a result, an HVDC MOG could reduce the amount of loop flows in the onshore grid since power flows can be actively steered. Reducing the occurrence or size of these loop flows could reduce grid losses. However, the exact effects of the HVDC MOG on the onshore grid losses remain unclear until different operational strategies have been modelled in more detail.

In the benefit analysis, the losses of DC lines and converters are calculated for each hour of the simulated year. The result from each offshore topology is compared afterwards. This is different to the ENTSO-E methodology, in which the simulations are performed of the system with and without the new project. Lower losses are an advantage of a topology, as this could result in less overall generation and therefore less generation costs.

The losses of the AC system are not calculated, as it is only available as a node model and interconnectors are modelled as lossless connections. An exception is the HUB concept, the offshore AC connections are modelled with all parameters to calculate the losses. This approach leads to some problems of comparability between the offshore concepts. While power flows from OWFs to other markets in the EUR, NAT and HUB concept can happen entirely on the offshore system, their exchange in the BAU concept can be accomplished by either using the AC interconnectors (modelled by NTC values) or available HVDC interconnectors. Only the latter counts towards the loss calculation. This results in an advantage for the BAU concept when using this approach and will lead to significant lower losses for the concept. It is therefore advised to neglect the difference in grid losses between he concepts and qualify the amount.

7.3.2.2.5 B6: SECURITY OF SUPPLY - ADEQUACY

The adequacy of the power system refers to the existence of sufficient facilities within the system to supply demand. It evaluates whether the system is adequately equipped to supply demand, also in case of (unscheduled) outages of transmission equipment. In order to do so, there needs to be sufficient generation capacity available as well as adequate transmission and distribution networks with sufficient capacity. A MOG could significantly improve the adequacy of the system compared to radial wind evacuation connections. As a MOG would create alternative paths for power evacuation, an outage of the primary connection to shore would have no or smaller effects compared to the radial approach.

The valuation of the adequacy benefits can be done by computing the difference in adequacy levels between the four concepts. The generation adequacy levels are usually expressed with the two metrics LOLE and the ENS. The LOLE represents the expectation that the available generating capacity cannot meet the load and is usually expresses in hours per year. The ENS on the other hand represents the expected amount of electricity that cannot be delivered per year, expressed in GWh per year.

As the computation of the ENS is not possible with the current status of the developed operational dispatch simulation, only the metric for LOLE can be used to quantify the adequacy. Additional to the LOLE expressed in h/year, the accumulated missing energy is also given.

7.3.2.3 OVERVIEW SIMULATION AND VALUATION METHOD

The operational simulation is an iterative process, containing different modules with each having a specific purpose (Figure 7-5). Following the operational simulation is a benefit analysis module that calculates the KPIs from values determined as a result of the operational simulation. Each module and its function are described in the following.

The complete transmission system with all the information available is stored in the *Internal Grid Module*. This module contains different classes for each component of the electrical system and is able to store data necessary for load flow, short circuit, reliability calculations and more. This module stores also all SUCs, which represent each one hour of the year and contains the specific maximum active power of each generation unit as well as the load to cover in each market area. Furthermore, the SUCs are grouped into months for easy access during the optimisation process.

As the data stored in the *Internal Grid Module* contains too much information for the operational simulation, has some necessary values not directly available and others dispersed over several classes, a *Grid Data Module* collects only the necessary information for the operational simulation. Additional information obtained from load flow calculation is also prepared and stored in the module, as well as specific information regarding the offshore

system or NTCs that have to be considered during the optimisation. This information is stored in a so-called *GridDataModel* and updated for each SUC every time after a load flow calculation. These are necessary to test for convergence of the grid and obtain the most current load flow dependent values.

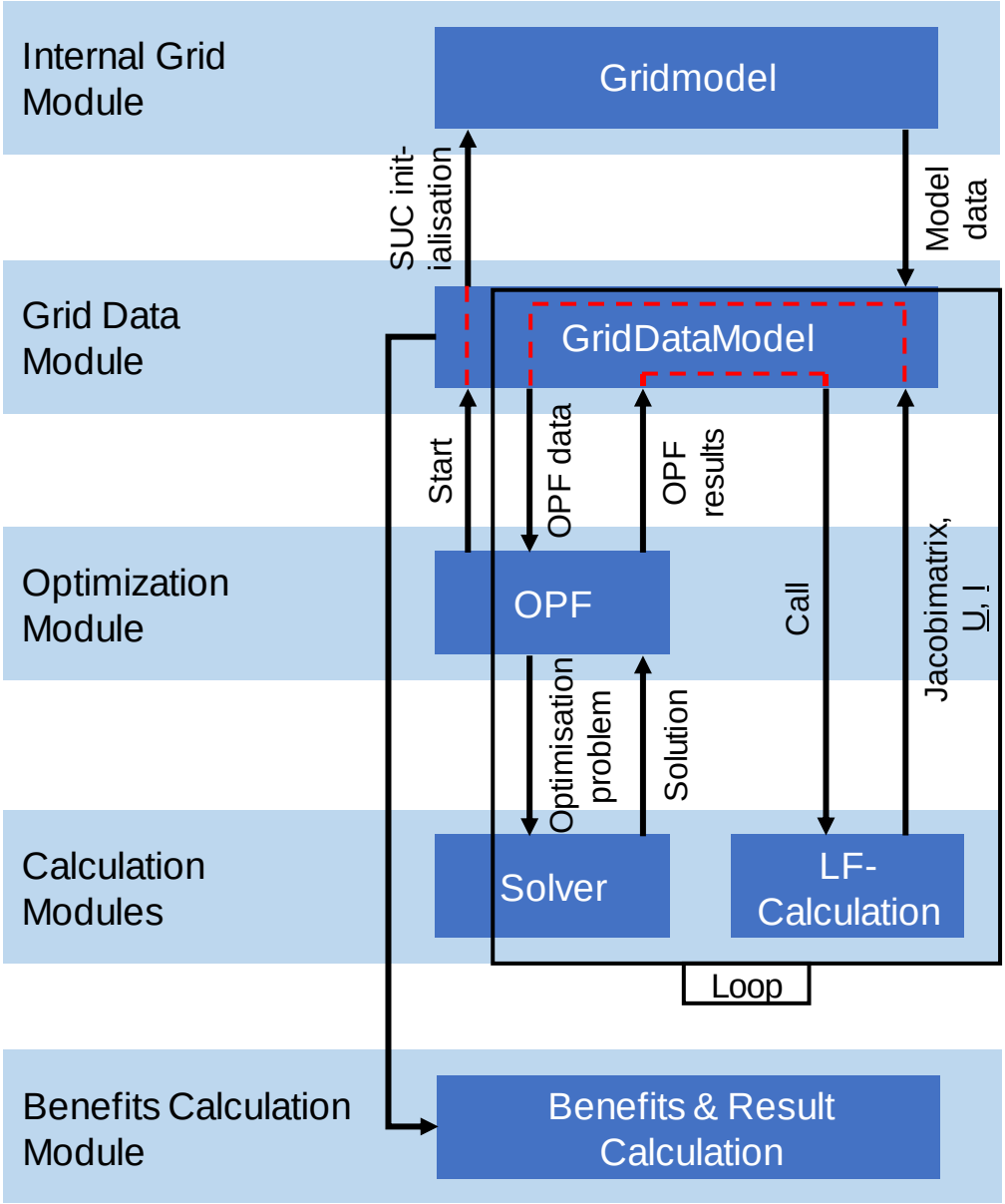


Figure 7-5 - Overview operational simulation and benefit valuation process.

The optimisation module is coordinating the operational simulation and can access all the data of the *GridDataModel* to construct the mathematical optimisation problem for the solver. Depending on the topology, different constraints have to be included and termination criteria have to be defined for an optimal status. The solver module is external in order to make switching between different solver software solutions easier. The optimal solution of the solver is processed in the OPF module and written to the *GridDataModel*. A new LF-calculation is carried out with these new setpoints and the load flow dependent data is again written into the GridDataModel and prepared by the optimisation module for a new iteration. The optimal status is achieved when the change of generation costs between iterations is below a defined threshold and no thermal limit violations on equipment occur.

In the end a benefits calculation module determines all the CBA relevant values and exports these for further analysis into sorted files. These exported files contain the converter and generation unit setpoints, utilization of lines and cables, NTC utilization between market areas, losses and market area specific values such as prices and LOLE for each hour of the year. By exporting the initial values before the operational simulation, final values and the potential left unused, other KPIs can be calculated, such as the curtailment of renewables.

7.3.3 DESCRIPTION OF INPUT DATA

In order to run the benefit analysis and obtain usable results, time has to be spent on preparing input data for the years to simulate. The more detailed this data, the better the results. This leads to the first obstacle: predictions of the future European power plants are getting more vaguely with each year into the future. A trusted source for this data is the ENTSO-E, as the institution performs every two years market simulations within the TYNDP for the future European transmission system. The input data should be developed together with the member TSOs and include country-specific political driven changes. The data contains predictions for the years 2025, 2030 and 2040 and is openly available on the internet.

That data contains the basic information needed to calculate the marginal costs for each year, which includes the efficiency per fuel type, O&M costs as well as CO_2 costs for different scenarios. Also available is the predicted installed generation capacity for each European market area per fuel type, time series of the aggregated load per market area node, as well as planned NTC values for bilateral interconnections between market areas.

The AC node models used in the simulation are the same for all four concepts. As described before, each market area is represented as one node with a generation unit attached for each fuel type. Whereas for the development of the offshore topologies only the North Seas adjacent countries are considered, the benefit analysis uses a wider European scope (seen in Figure 7-6). A simulation of the whole EU28 has not been adopted because of two main reasons:

- Some parts of the Eastern European system are electrically too far away to take advantage of the additional infeed of renewable energy into the system. The market exchange will be limited to the neighboring countries of the North Seas neighbors. The selected market areas are already sufficient and could be reduced. This has especially an influence on the computation time, as each node leads to additional variables and constraints.
- Another realization was the slim availability of input data for market areas in Eastern Europe. Whereas the ENTSO-E TYNDP provides the same basic data for all countries, additional data derived from the ENTSO-E Transparency Platform was not always available and made a simulation impossible with such an extensive observation area.

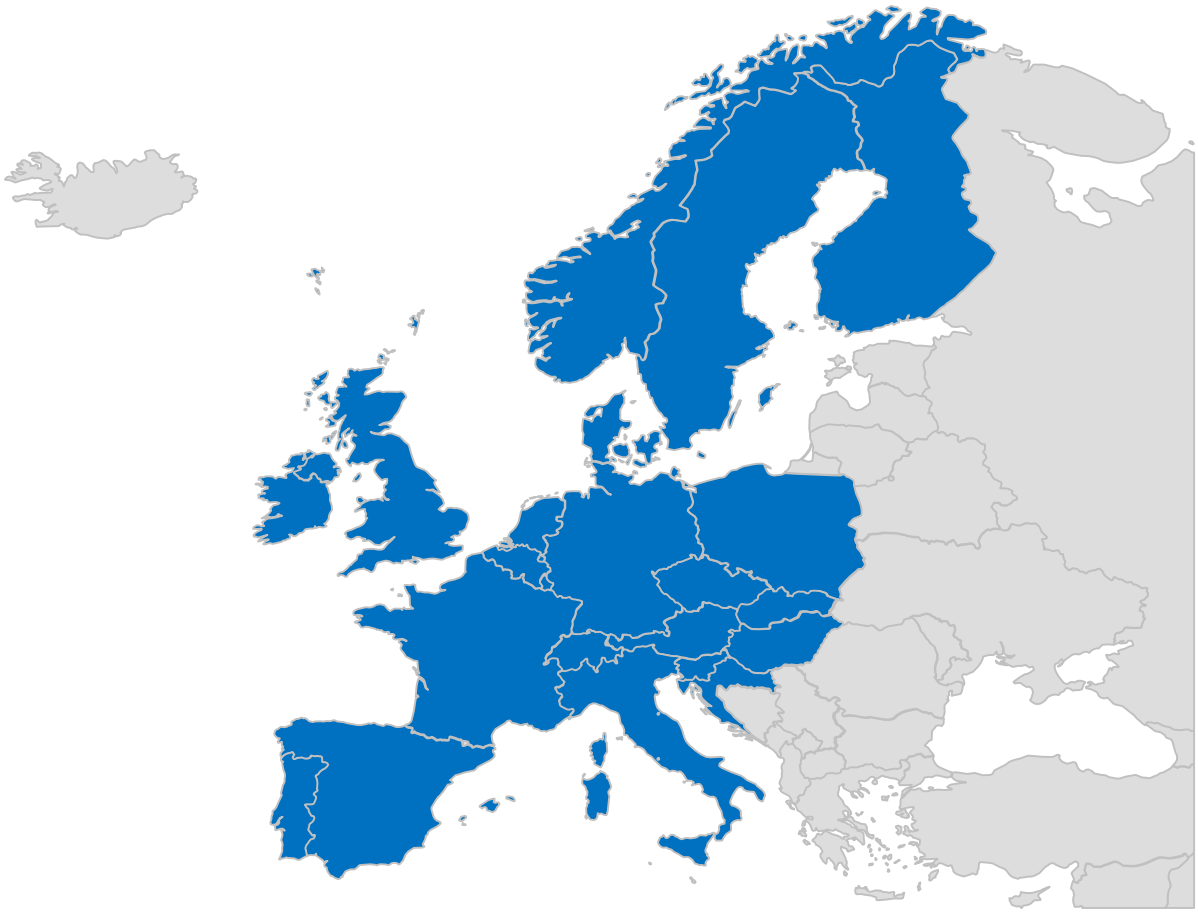


Figure 7-6 - Countries included in benefit analysis (some countries are split into market areas).

Within these AC node models for each scenario year, the developed offshore topologies are imported. The onshore converter stations connect to the AC nodes. For each offshore node an AC busbar is created, which connects a generation unit (the offshore wind farm) and the offshore converter station to the DC system.

7.3.3.1 ASSUMPTIONS AND DATA PREPARATION

The data provided by the ENTSO-E does not contain all the information necessary to perform the operational simulations for the benefit analysis. One of the reasons according to the ENTSO-E is the outsourcing of certain TYNDP steps to external partners. NDAs and licensing restrict publishing the results of the partners work.

In order to overcome this obstacle, certain assumptions have to be made. These are fully described in the following.

7.3.3.1.1 WEATHER YEAR

The ENTSO-E divides weather-dependable input data into three possible climate years: wet, dry and normal. The classification depends on the rain and snowfall during the year in the European countries and is given in the yearly reports.

In the following simulations a wet weather year has been taken into account. The ENTSO-E defined 2007 as a year with above average rainfall within the TYNDP2018 load data; examples given for the dry and normal weather year are further back. As 2007 is the only year where wind and generation data are available, it was chosen as the background for the simulations. The decision influences the load, availability of PV and wind generation, as well as the natural inflow of hydro generation.

7.3.3.1.2 DATA FOR MISSING SCENARIO YEARS

The ENTSO-E TYNDP 2018 dataset contains data for the years 2025, 2030 and 2040 only. As the data for the years 2035, 2045 and 2050 is missing, an interpolation and extrapolation approach has been used.

The missing data for the year 2035 has been interpolated with 2030 and 2040 being the base years and referenced by the three different scenarios. The GCA (High) scenario differs in this interpolation slightly, as 2030 has no GCA scenario. In that case, the ST scenario in 2030 is the basis for the interpolation.

For the years 2045 and 2050 a linear increase or decrease of installed generation capacity as in the years before has been assumed. An exception is made with the increase of hydro generation. The installed generation capacity of these fuel types is locked to the level of 2040, as a further increase would be somehow unrealistic with respect to the hydro potential determined in several studies.

7.3.3.1.3 AVAILABILITY OF RENEWABLES

The ENTSO-E TYNDP dataset contains only the installed generation capacity for each fuel type. Whereas most conventional generation units could always operate in theory up to this level when needed, renewables are dependent on wind and solar radiation. In order to simulate this weather dependent fluctuation, country and fuel type specific capacity factors are used. These are MERRA-2 data and are available for several years back in time, which makes it possible to collect data of one consistent weather year.

The derived capacity factors, which have a value between 0 % and 100 %, are then multiplied with the installed generation capacity. The results are weather dependent maximal generation setpoints of these renewables.

7.3.3.1.4 AVAILABILITY OF HYDRO GENERATION

The hydro generation is divided into three types: hydro-pump-storage, hydro-run and hydro-reservoir (description in Section 7.3.2). Each generation type is modelled differently and needs therefore different input data.

Similar to renewables, the ENTSO-E TYNDP provides only the installed generation capacity of the turbines as well as the installed pump capacity of hydro-pump-storage. As the hydro-generation is also weather-dependent, additional data has to be obtained to simulate a realistic dispatch.

Additional research has been carried out to obtain the storage capacity of the hydro-pump-storage generation per country. This is needed to simulate the operation of the turbines and therefore draining of the upper water reservoir and ensuing filling via the pumps. The storage capacity is the limit in which turbine and pump operations are possible. Additional inflow of water into the system because of the weather is not modeled for this generation type.

Hydro-run generation is dependent on the weather, e.g. how much it has rained or it had been snowing during the winter season. The ENTSO-E Transparency platform provides for some countries the past generation output values per fuel type. When taken from a specific year, e.g. a wet or dry year, and divided by the installed generation, capacity factors can be derived which are then multiplied with the scenario years installed generation capacity. This resulting maximum generation capacity then contains the seasonal differences in generation.

The generation of hydro-reservoir is limited by a maximal monthly energy budget. In order to simulate the seasonal behavior of natural inflows, the generated energy per month in each country is extracted from the ENTSO-E Transparency Platform and then extrapolated with the installed generation capacity in the specific scenario year. This results in a monthly limit for how much energy can be generated. As the natural inflow of

water is higher in the spring, the energy budget could allow a higher generation, whereas in dry summers the energy budget avoids emptying the complete reservoir.

7.3.4 RESULTS PER KPI

The results of the operational simulation are presented in this section with an analysis and interpretation of the KPIs described in section 7.3.2. As an analysis of the results per topology would not be beneficial, the four concepts are viewed together and compared to each other per KPI. The reasons behind the different operational outcomes are explained in detail, which are most likely because of the specific topology and their basic design principles explained in this document in Chapter 5.

The following Sections for each KPI are mostly two-part. The first part has a look in detail at the North Seas countries, which are Belgium, Denmark (West and East), France, Germany, Great Britain, Ireland, Netherlands and Norway. The second part considers all simulated countries (see Figure 7-6) in the result analysis. This structure is useful in order to show the effects of the directly involved countries when building an offshore system, but also the interaction with other countries interconnected via a strong onshore system.

The following KPI results will only show the benefits of the developed High wind scenario in this version of the document. The results of the Central and Low wind scenario are presented in Appendix VII.

7.3.4.1 B1: SOCIO-ECONOMIC WELFARE

The generation costs of the four concepts are calculated by multiplying the cumulated generation per fuel type of the whole year with their specific marginal costs (Table 7-2). These flexible generation costs should be as low as possible in order to achieve a maximum societal benefit. As the marginal costs are derived from the cost of the fuel as well as the CO_2 costs of the corresponding scenario year, the marginal costs of conventional thermal generation are becoming more and more expensive until 2050 in the High wind scenario. This results in the dispatch of as much RES as possible, followed by hydro and nuclear generation.

Table 7-2 - Marginal costs per fuel type in the High wind scenario.

		2025	2030	2035	2040	2045	2050
Marginal costs [€/ MWh]	Biofuels	162.73	162.73	227.53	194.61	160.67	189.47
	Gas	64.15	86.05	92.18	98.32	108.25	116.49
	Hard Coal	59.46	86.45	98.26	110.08	129.80	146.00
	Hydropump	3.00	3.00	3.00	3.00	3.00	3.00
	Hydrorun	2.50	2.50	2.50	2.50	2.50	2.50
	Hydroturbine	6.00	6.00	6.00	6.00	6.00	6.00
	Lignite	54.59	78.54	95.02	111.50	136.48	157.88
	Nuclear	14.13	14.13	14.13	14.13	14.13	14.13
	Oil	68.08	92.39	109.12	125.85	151.20	172.70

		2025	2030	2035	2040	2045	2050
	Other non-RES	77.29	101.24	117.72	134.20	159.18	180.36
	Other-RES	62.00	62.00	62.00	62.00	62.00	62.00
	RES (Solar & Wind)	0.00	0.00	0.00	0.00	0.00	0.00

The generation costs of the four concepts are illustrated in Figure 7-7, which shows that in 2025 these are almost the same at 40.5 bn €. This value slightly increases in 2030, with the HUB concept reaching 41.1 bn €. The reason behind this behaviour is the increase in CO_2 emission costs with not enough RES capacity as an alternative to thermal generation to offset these costs. This generation switch is possible from 2035 onwards. The generation costs then decrease every 5 years and reach almost 40 % of the initial costs in 2050.

These determined generation costs are quite similar to each other, with the NAT concept costing 411 million € less than the EUR concept. The HUB concept is also slightly better than the EUR concept at 15,63 bn €. The BAU concept has the highest marginal generation costs of the four concepts in the simulated scenario year 2050.

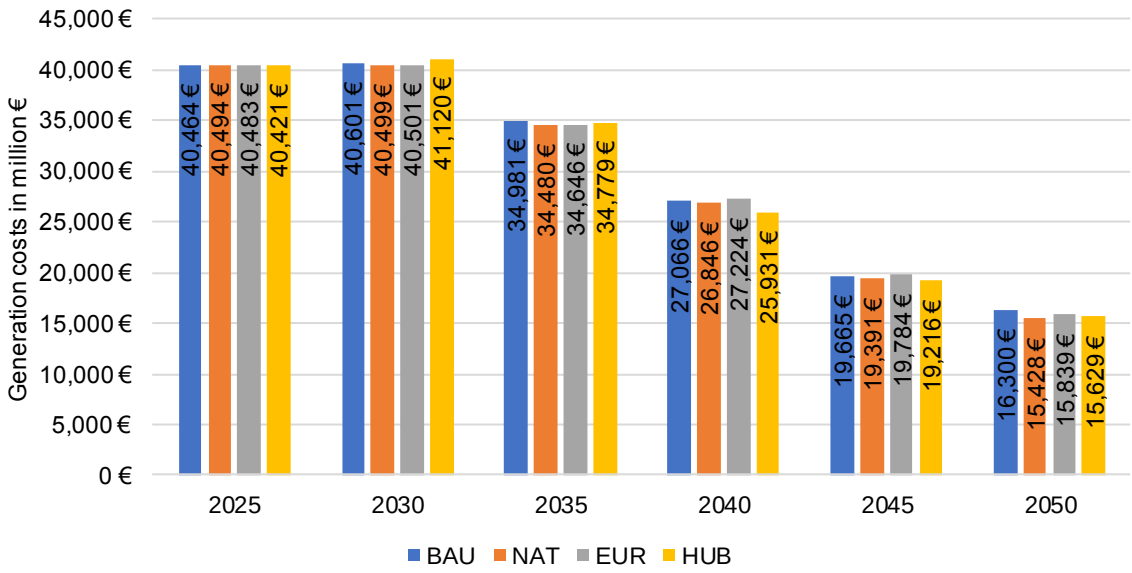


Figure 7-7 - Generation Costs of North Seas Countries for all concepts and scenario years.

These numbers and rank order are only valid when looking at the North Seas countries. When considering all simulated European market areas, the rank order slightly changes, as shown in Figure 7-8. The topology of the NAT concept results in 44.53 bn € yearly generation costs, followed by the HUB concept and EUR concept with ~313 million €, respectively 461 million € more. The BAU concept is the costliest again with more than 1.2 billion € more than the NAT concept in accumulated marginal generation costs.

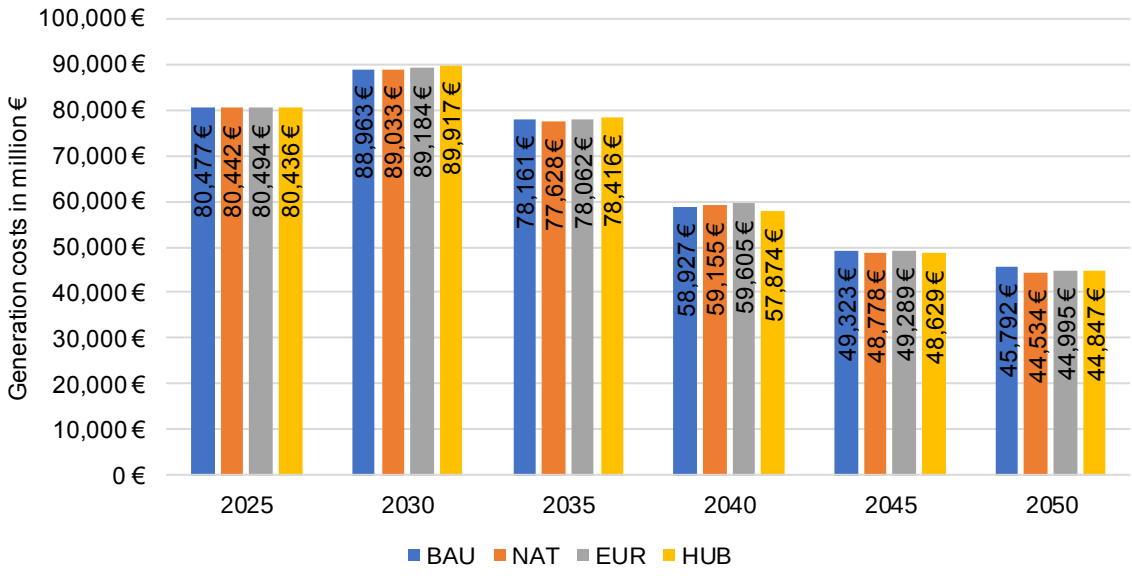


Figure 7-8 - Generation Costs of all simulated countries for all concepts and scenario years.

When taking the BAU concept in each scenario year as the base case and illustrating the deviations of the NAT, EUR and HUB concepts to this base case, the low differences in marginal generation costs between the concepts become even more obvious (Figure 7-9). The generation costs are almost the same in 2025 between the four concepts, with the highest deviation of almost -3 % occurring in 2050 with the NAT concept. However, this generation costs advantage is not in all simulated scenario years available. A cumulative value for the generation costs of all four concepts is therefore necessary to obtain an overview of the benefits over the whole simulated period.

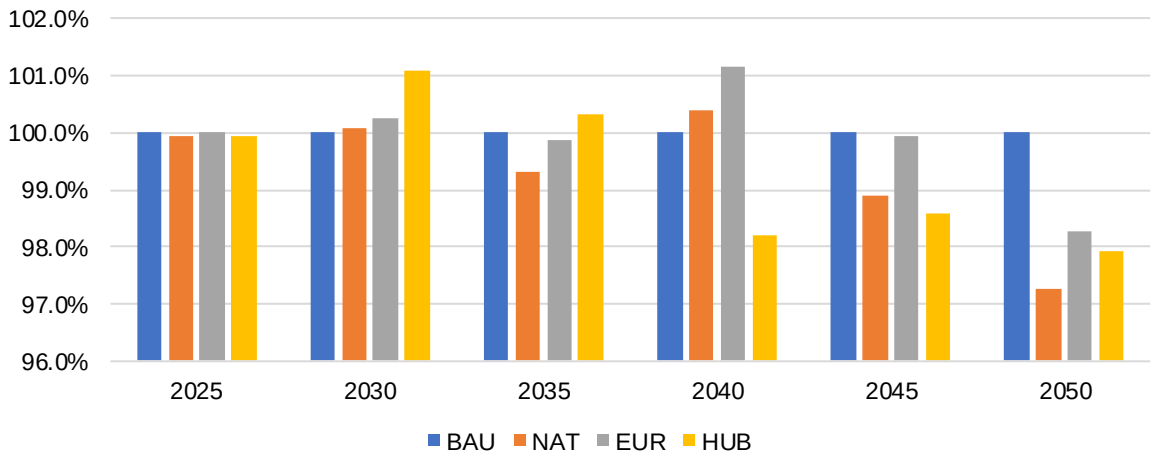


Figure 7-9 - Deviation of NAT / EUR / HUB scenario per scenario year.

When looking at the deviation per concept in each North Sea country, different interactions can be seen. An exemplary result of the scenario year 2050 is seen in Figure 7-10. Whereas Germany's (DE) and Great Britain's (GB) generation costs vary widely between the four concepts, the rest of the countries' costs stay similar. The NAT and EUR concepts result in the lowest generation costs in Germany and on the other hand the highest costs in Great Britain. These results show the difference in onshore connection capacity between the concepts and in which direction the generated energy can be evacuated.

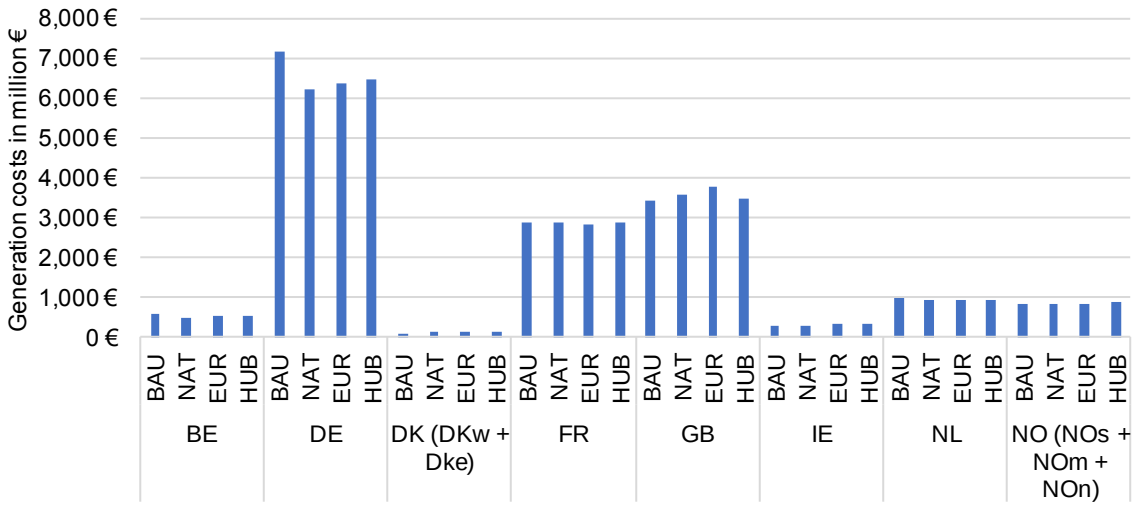


Figure 7-10 - Country-specific generation costs per concept in 2050.

The final values of the socio-economic welfare are calculated by taking the BAU concept as the base case and determining how much better the NAT, EUR and HUB concepts compare against it. For this final evaluation the cumulated marginal generation costs are calculated, with the assumption that the state of the topology from each scenario year is fully existent for the five-year period. While it is not the most accurate calculation method, it is in line with the method used in Chapter 6.

The results in Table 7-3 show that the NAT concept has by far the highest socio-economic welfare, with 10.4 billion € saved over the 25-year period compared to the BAU base concept The Hub concept has a benefit of over 7.6 billion € in the same period. The fully meshed EUR concept on the other hand has only a slight advantage, with around 70 million € saved compared to the BAU concept. Together with the installation costs, the socio-economic welfare offers a better understanding of which concept has the better return value for the European society.

Table 7-3 - Socio-economic welfare of the simulated concepts in the High scenario.

CONCEPT	SOCIO-ECONOMIC WELFARE
NAT	10.37 billion €
HUB	7.62 billion €
EUR	0.07 billion €

7.3.4.2 B2: RES INTEGRATION

The analysis of the curtailment gives an insight into the interconnection of market areas. The installed generation capacity is in all four concepts similar; less curtailment is therefore a result of an optimised energy exchange to markets where renewable energy is not sufficient enough to cover the load. The low marginal costs of renewable generation in the simulation make curtailing the last option. Less curtailment could also lead to lower generation costs but has to be weighed against the installation costs of additional interconnection. It could also be possible to use some kind of storage or Power-to-X instead of curtailment. These options are not integrated in this operational simulation, as developing scenarios for these new technologies is part of other projects and can differ substantially.

When looking at the results in Figure 7-11, the HUB concept shows rising curtailment as early as 2030. Whereas the other concepts stay below 2 TWh of curtailed RES, the HUB concept is already at 11 TWh. The increasing generation of renewables up to 2050 is accompanied with rising curtailment in all four concepts. The NAT and the EUR concepts meshed topologies allow for a better evacuation to shore and market exchange, with a slight advantage of the NAT concept in 2045 and 2050. The BAU and especially the HUB concept on the other hand have to curtail more RES.

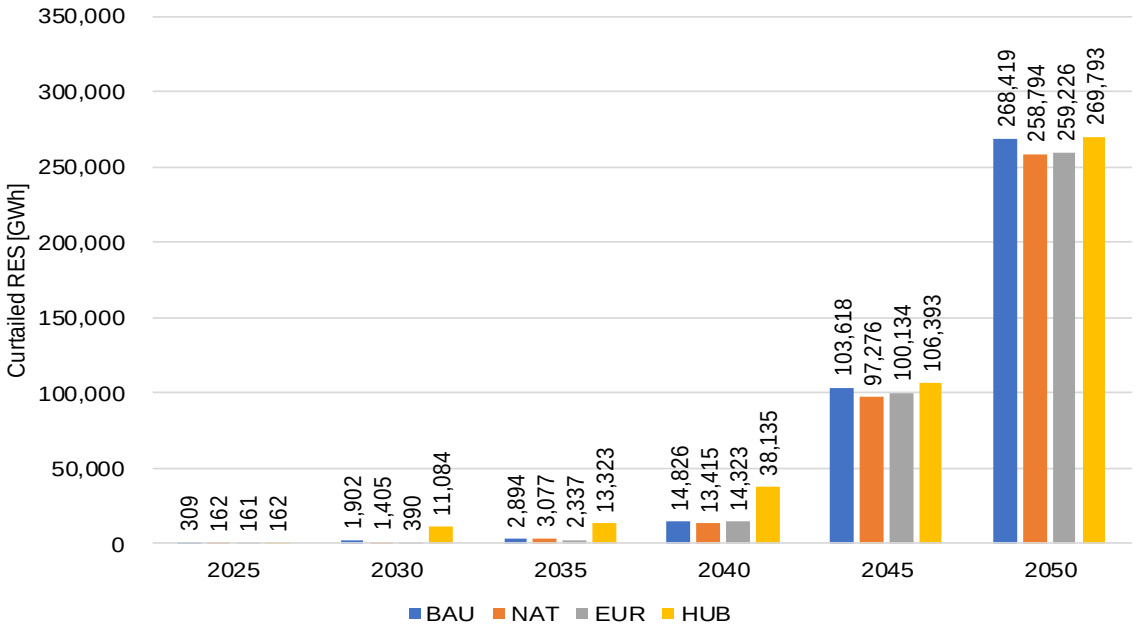


Figure 7-11 - Curtailed RES of North Seas Countries per concept and scenario year in GWh.

When looking at all countries included in the operational simulation, the margins between the four concepts and the ranking order stays similar. Refer to Figure 7-12. The NAT concept has now the lowest sum of curtailed RES with 391 TWh, followed by the EUR concept with a similar result. The radiant topology of the BAU concept leads to higher curtailment of 400 TWh in 2050 and the HUB concept has the highest curtailment in 2050 at 401.5 TWh.

Operational simulations with only the North Seas countries have shown different results for the four concepts. The missing flexible hydro generation in markets such as Austria or Switzerland lead to disadvantages for the EUR and NAT concepts with higher curtailment than the BAU concept. The comparison shows that a holistic analysis of the European transmission system is necessary to fully simulate the interaction of flexibility options in different market areas. Considering the political will towards a European domestic market which will lead to the upgrade of the available NTC between (onshore) market areas, certain geographical advantages could play a bigger role in the future with a growth in installed generation capacity (e.g. hydro-pump storage in Norway).

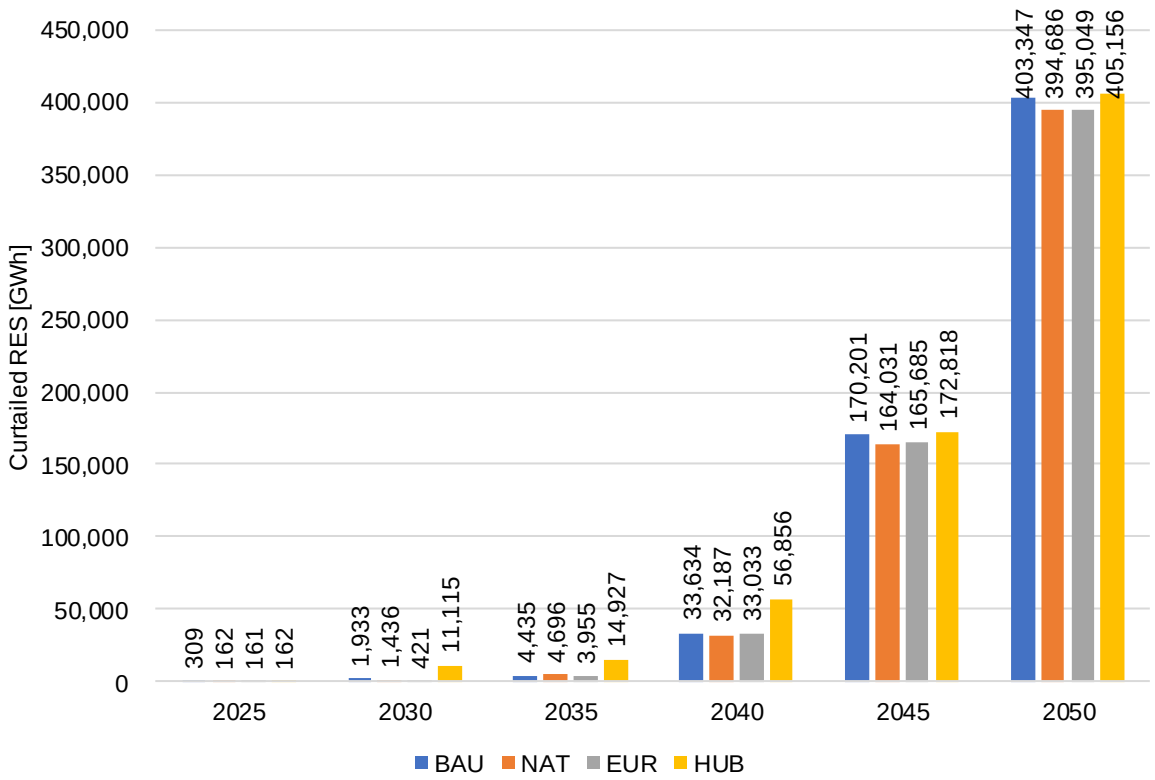


Figure 7-12 - Curtailed RES of all simulated countries per concept and scenario year in GWh.

A deeper analysis of the curtailed generation of renewables in the North Seas bidding zones shows that up to 2035 only the offshore generation is being curtailed. The following years the installed generation capacity of onshore generation (PV and Wind-onshore) as well as Wind-offshore in other areas than the North Seas is rising to an amount that curtailment of these generation types becomes also necessary. An example is given in Figure 7-13 which shows the curtailment of North Seas bidding zones in 2050. More than 22 % of the possible offshore generation in the Baltic and North Seas has to be curtailed in that simulated year in the BAU concept. A conclusion is therefore, that in order to avoid this costly curtailment additional research and the installation of flexibilities is necessary. The research into energy storage options like battery storage or power-to-X should be concentrated right now to have the right technology available in 10 to 20 years when needed. This high increase of renewables has to be linked with the flexibilities or problems could arise when classical thermal generation units are also decommissioned (see Section 7.3.4.5).

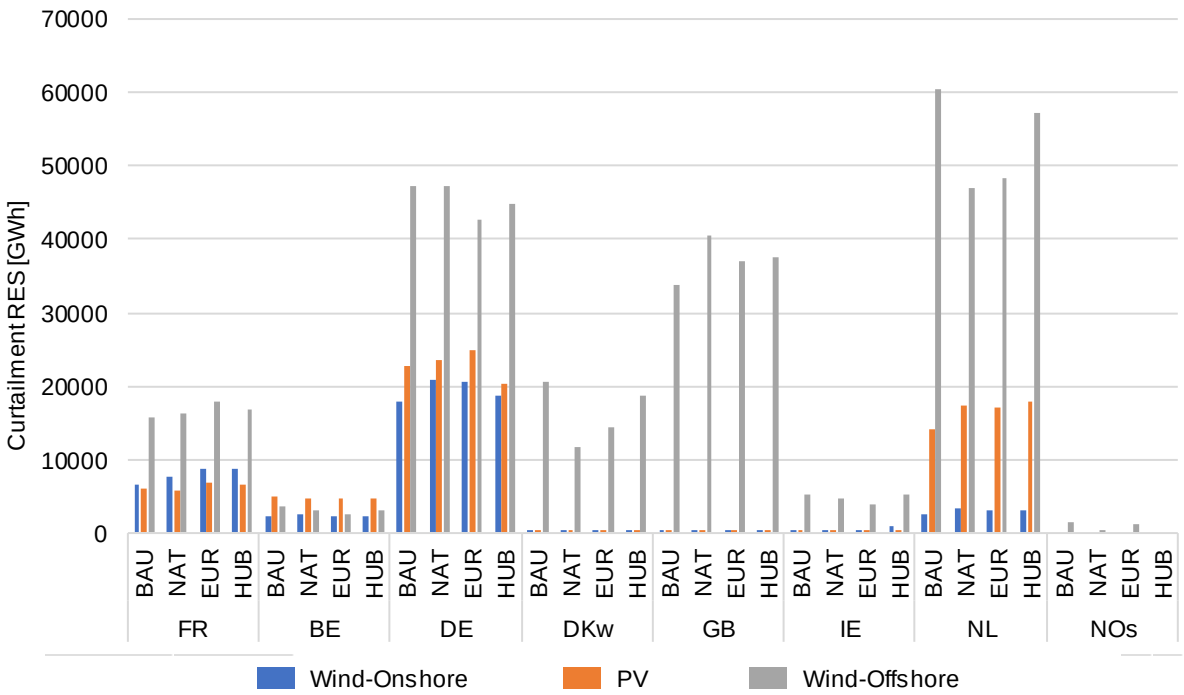


Figure 7-13 - Curtailed RES per fuel type and bidding zone in 2050.

7.3.4.3 B3: CO_2 VARIATION

The results of the CO_2 emissions show in all four concepts a steady decline until the scenario year 2050. Less than 12 % of CO_2 emissions of the original 2025 values remain in 2050. As no storage and other flexibilities, such as Power-to-X, are considered in the operational simulation, curtailment of renewables increases up to 2050. If additional storage options would be utilised, even lower emissions could be possible. These additional storage options could also be hydro-pump storage in countries like Norway and Austria. Additional interconnectors could result in an increased utilization of these hydro generation units, as for example an energy exchange between Norway and Germany in both directions for pump operation or turbine operation would occur almost all the time. If these additional interconnectors make sense from an economic perspective is a different topic and has not been analysed yet. On the other hand, if the European Union tries to further reduce the CO_2 emissions, not all interconnections could be economic driven but ecologic instead.

The difference in CO_2 emissions between the four concepts is in all scenario years marginal, as illustrated in Figure 7-14. The NAT concept has in 2050 the lowest CO_2 emissions with 28.6 million tonnes, the BAU concept as the base case has the highest with 31.3 million tonnes. Furthermore, the NAT concept has lower CO_2 emissions than the BAU concept in the other scenario years after 2025 as well.

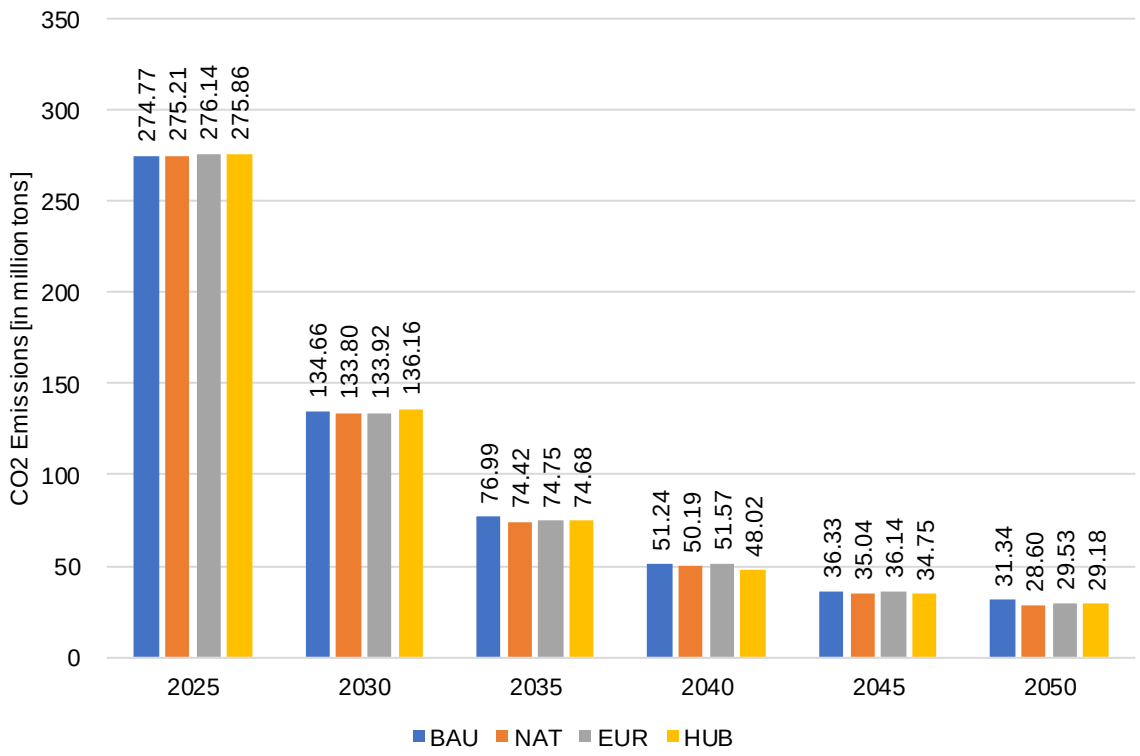


Figure 7-14 - CO_2 emissions of North Seas countries for each scenario year and concept in tonnes.

The evaluation of CO_2 emissions in all simulated countries (Figure 7-15) shows no change in order of the four concepts in 2050. The BAU concept still results in the most CO_2 emissions with 103.07 million tonnes, whereas the EUR concept is the third best option in 2050 with an output of 100.87 million tonnes. A further improvement would be the HUB concept with a slightly better 100.68 million tonnes. The best concept in the scenario year 2050 would be again the NAT topology, because CO_2 emission can be as low as 100.05 million tonnes.

These determined numbers are quite similar, the differences of the NAT, EUR and HUB concepts being less than 3 % compared to the BAU base case. The absolute difference of 3 million tonnes on the other hand is a value which is probably an appreciated reduction within the European Union, especially when considering a CO_2 price of 184.4 €/tonne in 2050.

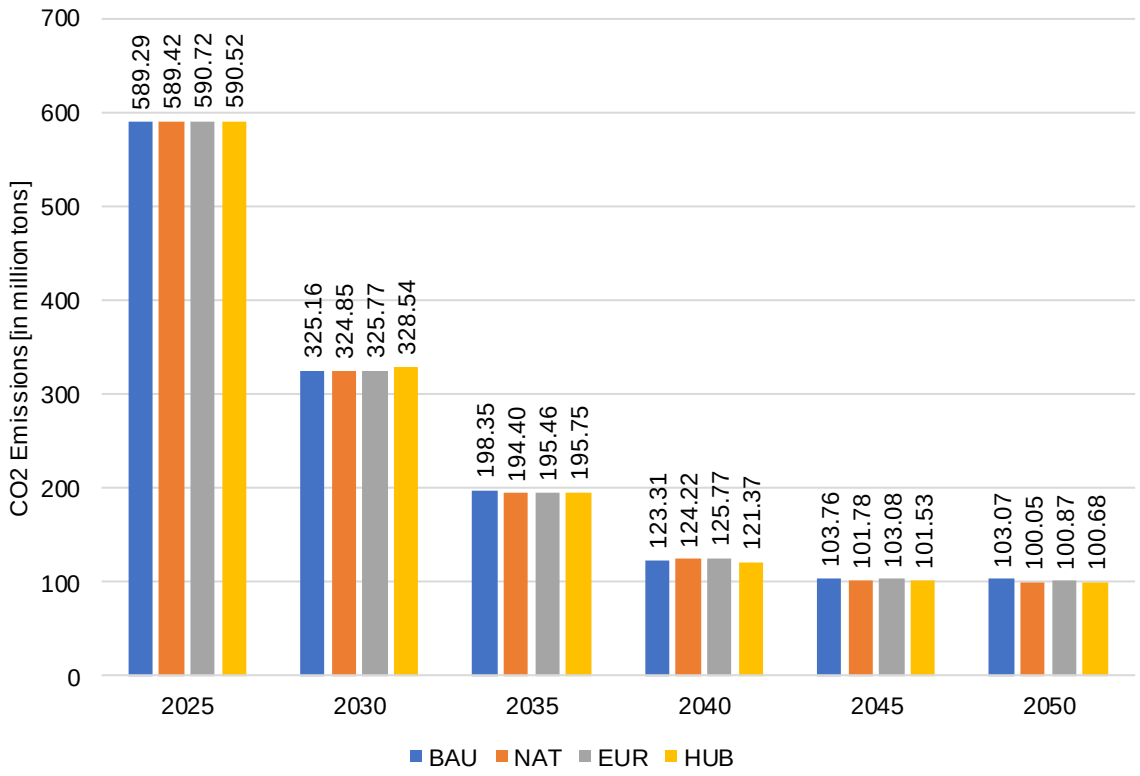


Figure 7-15 - CO_2 emissions of all simulated countries for each scenario year and concept in tonnes.

7.3.4.4 B5: GRID LOSSES

The comparison of the losses is an analysis of the estimated system losses in the offshore system. As the onshore system is modelled with ideal components in the operational simulation, only losses of converters, cables and offshore transformers of the offshore topologies are being taken into account. The problem with this method is that a comparison of the four concepts with each other is not possible. The BAU concept uses the shortest distance to shore for evacuating the generated energy. The exchange with other bidding zones is then coordinated from the onshore bidding zone node and can happen via offshore or onshore interconnections, the latter option being without losses. This results in incomparable losses because in the BAU concept the energy exchange could happen on lossless onshore interconnections, e.g. between Germany and Denmark West, whereas in the EUR concept the offshore connection from the German OWF to the Danish shore is being used and losses occur. These discrepancies show that a comparison makes only sense within a concept and not between the different developed concepts. Furthermore, Deliverable 7.11 advises to neglect the difference in grid losses in the practical CBA.

Nevertheless, the determined losses per concept for each scenario year are shown in the following Figure 7-16 to give a better overview.

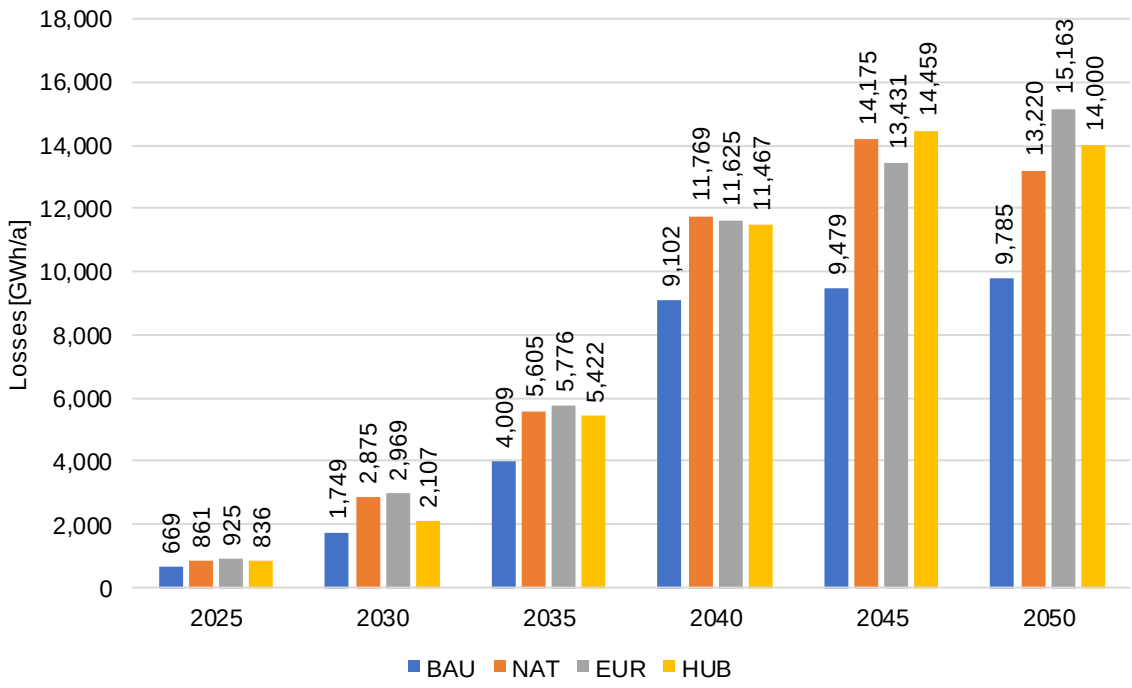


Figure 7-16 - Accumulated losses of the four concepts for each simulated year.

Figure 7-16 shows the accumulated losses of the four concepts in each simulated scenario year. Quickly apparent are the lower losses of the BAU concept in all six scenario years and the nearly stagnating values in 2040 to 2050. This behaviour can be attributed to the aforementioned factor.

The NAT, EUR and HUB concepts on the other hand have substantially higher losses in all scenario years. As mentioned before, a comparison between the concepts should not be carried out. Noted should be that the EUR concept has longer transportation distances from generation to load which could result in higher transmission losses in the cables.

7.3.4.5 B6: SECURITY OF SUPPLY – ADEQUACY: LOSS OF LOAD EXPECTATION

As described in previous Chapters, the operational simulation can determine hours of the simulated years, in which not sufficient generation potential and NTCs are available to cover the existing load in each market area. The missing energy difference is defined as *Loss of Load Expectation* (LOLE). The amount depends on the generation input data for the future generation park, available NTC between market areas and the offshore topology. As the used input data is taken from the ENTSO-E TYNDP 2018, already insufficient generation is transferred to this operational simulation. The developed offshore topology implemented into the European node model can however improve the available insufficient supply with additional interconnection capacity.

The results can be seen in Figure 7-17 for the North Seas countries. The lower interconnection capacity of the BAU concept leads to higher LOLE at 67.3 GWh in the scenario year 2050. On the opposite side is the NAT concept with only 17.4 GWh. The HUB concept has a slightly higher LOLE with 21.5 GWh, followed by the EUR concept with 23.4 GWh.

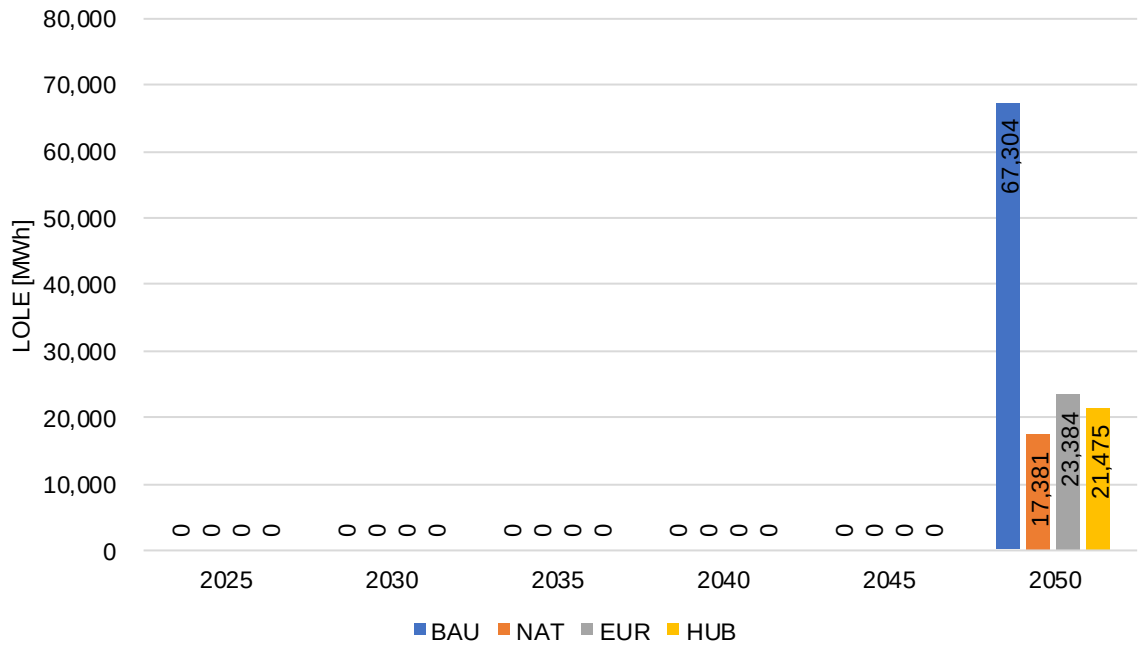


Figure 7-17 - LOLE of North Seas Countries per concept and scenario year in MWh.

The reason for LOLE occurring in the simulations only in 2050 is the high penetration of renewable generation and even lower installed generation capacity of classical thermal generation. Rare occurrences of low wind speeds and no solar radiation ("*Dunkelflaute*") in winter can no longer be absorbed with gas turbines and hydro generation through interconnections. One example is Denmark (East and West), with 22 hours of LOLE in the NAT concept and up to 2.6 GW in power shortage during 2050 (Figure 7-18). The installed capacity of hydro-pump storage is not sufficient anymore as the only storage option available, more flexible options should be considered. These could be, with the current research status in mind, either battery storage or power-to-X. Further discussion on this topic was already carried out in Section 7.3.4.2. Raising the NTC on strategic interconnectors could also be possibility, such as between Germany, Austria and Switzerland or Germany, Denmark and Norway. Less congestion on these interconnectors could mean a better utilization of hydro generation, but an overall view of the onshore system is needed to avoid bottlenecks within the meshed system. A sensitivity analysis performed in chapter 7.3.5.1 gives more insight into this topic.

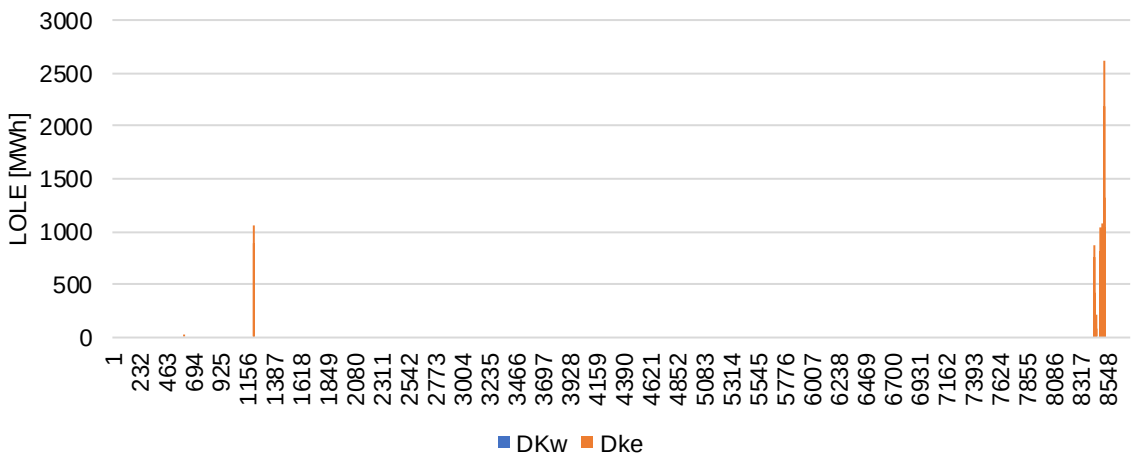


Figure 7-18 - Yearly overview of LOLE for Denmark in NAT concept in 2050.

The problem of insufficient energy occurs in the North Seas countries only in the scenario year 2050 in all four concepts. This changes when looking at all simulated countries, with LOLE appearing as early as 2030 in all four concepts in Finland. After consultation with members of ENTSO-E, it had been announced that the problem is known and part of the TYNDP data. As no additional interconnection including Finland (directly or indirectly) exists in the created offshore topologies, the LOLE value stays the same in all four concepts carried over from the TYNDP 2018, as shown in Figure 7-19.

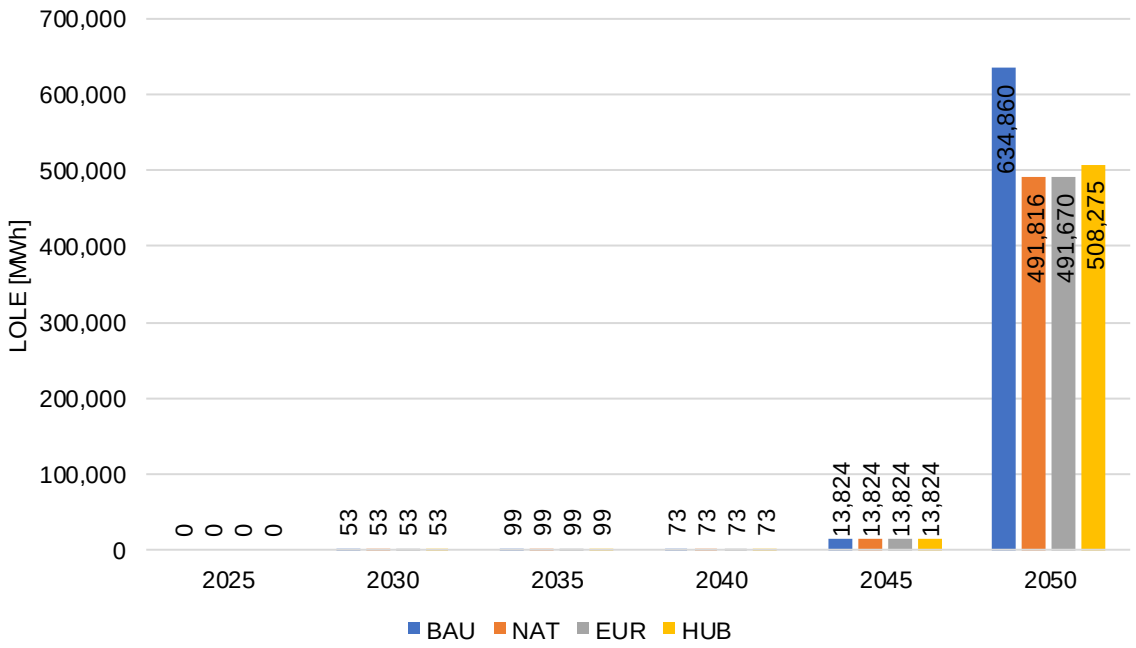


Figure 7-19 - LOLE of all simulated countries per concept and scenario year in MWh.

When analysing the absolute numbers for LOLE in hours per year in Table 7-4, the Czech Republic, Finland and especially Hungary stand out with very high values. This could be related to the linear extrapolation used to compile the generation input data for the scenario years 2045 and 2050. If the RES development had been slow up to 2040, the same rate of expansion continues to be used for the following ten years. This in turn might not be sufficient enough to compensate for the decrease in installed generation capacity of thermal generation. Together with the not sufficient interconnection capacity this could lead to loss of load, particularly pronounced in the countries mentioned above.

Depending on the offshore topology, the LOLE can also be decreased, which can be seen in Germany and Poland. The additional connection capacity to Germany because of the meshed offshore systems could (almost) completely avoid load shedding and even supply additional energy for the polish market to decrease the LOLE by 50 % in the NAT and EUR concepts compared to the base BAU concept. These results show very well why a benefit simulation should not be limited to the adjacent states only, as there may be further benefits for other markets as well.

Table 7-4 - all markets with LOLE in h/a per concept in 2050.

	Loss of Load Expectation [hours/year]									
	CZ	DE	DKe	DKw	FI	HU	NL	PL	SE3	SE4
BAU	115	11	15	0	84	215	2	22	0	4
NAT	115	0	22	1	83	223	0	13	0	2
EUR	117	2	12	1	84	226	2	11	1	5
HUB	137	1	19	0	84	240	1	16	0	2

7.3.5 ADDITIONAL SENSITIVITIY ANALYSIS

This chapter presents the additionally performed calculations of the operational benefit simulation to get a better understanding of the used input data. By doing this, better recommendations can be given to improve the utilisation of the renewable energy within the system.

7.3.5.1 RAISED NTCS BETWEEN ALL MARKETS

For this sensitivity analysis, all the available NTC values between the simulated markets are being raised to 10 GW in the EUR concept in the scenario year 2050 in the high scenario. This study investigates whether the additional interconnection could lead to less curtailment of renewables as well as a lower LOLE in certain markets. The idea is that a jointly developed European offshore concept would not just result in a higher collaboration offshore but also an improved integration onshore. The high increase of onshore installed RES generation capacity would make a case for additional interconnectors to take advantage of the temporal and geographical feed-in of renewables. Markets that showed still more than average amounts of thermal generation in 2050 (i.e. Poland or Czech Republic) could benefit from using renewable energy generated somewhere else and lower as a result their CO_2 emissions and market prices.

In order to better evaluate the results, a comparison between the original and the modified system in the EUR 2050 concept is carried out and the differences are highlighted.

Firstly, the sum of the CO_2 emissions of all simulated countries decreases by 54 million tons, which is more than 50 %. A reduction is in all markets achieved except in France, Spain and Switzerland, who have a slight increase in emissions. The greatest influence on the improvement have Italy and Poland, followed by Germany and the Czech Republic. They account for around 85 % of the saved CO_2 emissions. By using the integrated transmission system, Italy could decrease the production from gas power plants by 74 TWh and import more energy from neighbouring markets, such as Austria, France and Switzerland. These countries could function as transit market within the simulation for energy generated in Germany or the North Seas. Additionally, Italy can improve the utilisation of hydro-pump-storage power plants as well as PV and supply energy to other markets as well.

The overall generation costs of the whole year can also be decreased by 15.7 billion Euros. This is mainly achieved by a decrease in production of fuel types with high marginal costs, such as “othernon-RES”, oil, gas and “other-RES” and a higher utilization of renewables (Table 7-5). This of course also means less curtailment (Table 7-6). Longer operating hours can also be observed with hydro-pump-storage in all markets where available, as well as run-of-river power plants.

Table 7-5 - Delta of yearly generation [%] between normal simulation and simulation with raised NTCs for EUR concept in 2050.

	Biofuels	Gas	Hydro-Pump-Storage	Run-of-river	Hydro Reservoir	Lignite	Nuclear	Oil	Othernon-RES	Other-RES	Solarthermal	Solar-PV	Wind-Onshore	Wind-Offshore
Change in yearly generation [%]	-100	-45	+16	+4	+9	-13	+7	-87	-93	-19	-28	+3	+2	+8

Table 7-6 - Delta of yearly curtailment for RES [%] between normal simulation and simulation with raised NTCs for EUR concept in 2050.

	Solarthermal	Solar-PV	Wind-Onshore	Wind-Offshore
Change in curtailment [%]	+32	-21	-17	-34

The additional transfer capacity between the markets also results in no LOLE within the whole simulated year (for determined values before: chapter 7.3.4.5). All markets who have high amounts of hours with load shedding in the simulation with forecasted NTCs such as Finland, Hungary and Czech Republic are now able to import the needed energy from other markets. With the high concentration of RES in certain areas in Europe, becoming an import-oriented market could be a viable option for some. Therefore, the main focus in the future could be on developing interconnections instead of generation capacity. Depending on the development of pricing for storage, their development could also be a viable option to avoid loss of load in the future.

In conclusion, this sensitivity analysis shows benefits over all KPIs. Increasing the NTC values of the interconnectors could also be thought as a European copper plate and resembles a transmission system without bottlenecks. Even without transmission restrictions, curtailment of RES cannot be avoided, as sometimes the generation exceeds the load. Flexibility in the form of storage is therefore unavoidable in the future horizon of 2050 to effectively further decreasing the curtailment and CO_2 emissions within the European energy system.

7.4 QUALITATIVE ANALYSIS OF BENEFITS

The following Section describes qualitatively the benefit and residual factors that were not quantified in the Section before. For each separate benefit KPI a short description of the KPI is first given with the potential impacts of the MOG described. Then, an evaluation of the concepts on the KPI is performed where possible. A similar structure is applied in the residual factors, although a more in-depth study has been conducted for these KPIs. These Sections will therefore go into more detail regarding the methodology of this research, as well as a high-level comparison between the BAU concept and the meshed concepts.

7.4.1 B4: SOCIETAL WELL-BEING

The development of a MOG could result in benefits to society which are not fully captured by the indicators on socio-economic welfare (B1), renewable energy sources integration (B2) and variation in CO_2-emissions (B3). For example, the project could be valued on its contribution to sustainability. This has its effect on the society, without being directly captured by the other KPIs.

A MOG might have a positive impact on the preservation of the onshore landscape and could also reduce costs by mitigating the need for onshore grid reinforcement. This is because development of the MOG could replace the need for onshore grid reinforcements since new interconnection capacity would be created without disturbances in the onshore landscape. For example, the German onshore grid is required to facilitate power exchange between The Netherlands and Denmark. Since this grid is quite constrained – due to the high amount of offshore wind power infeed in the North of Germany – facilitating these exchanges would require onshore grid reinforcements in the future. Such onshore reinforcements have a spatial impact, since new power line corridors would need to be created. However, the construction of the offshore interconnector COBRAcable – linking the Netherlands with Denmark directly – reduces the need for onshore grid reinforcement in Germany, thereby having a positive impact on societal well-being [44]. It prevents new onshore power corridors to be created, which would permanently alter the landscape and could even endanger social acceptance. Furthermore, due to scaling effects,

MOG development may become cheaper than onshore grid reinforcements in the future. In doing so, the development of a MOG can have a positive impact on the preservation of the onshore landscape and potentially reduce costs as well. HVDC interconnection links can thus serve as 'bootstraps' for further grid development [45].

Secondly, a MOG could have spatial planning benefits over an uncoordinated approach in which the seabed would be transformed into a 'spaghetti' of power cables. The coordinated approach which would be used in the development of a MOG can benefit from improved spatial planning and reduce the overall grid length needed. For example, multiple corridors to shore could be created to bundle power cables from different wind parks on their route towards shore, as opposed to each wind park having a separate route towards shore. This decreases the impact of the power grid on the marine environment and can be regarded as an increase in societal well-being.

7.4.1.1 EVALUATION OF THE KEY PERFORMANCE INDICATOR

Scoring the societal well-being is a tedious task, as it includes the societal benefits that have not been taken into account by the SEW (B1). This is also acknowledged in Deliverable 7.11, where it is even stated that there is a risk of double counting the effects. It is therefore decided not to further evaluate the concept on this KPI in order to avoid possible double counting.

7.4.2 B7: SECURITY OF SUPPLY - FLEXIBILITY

Apart from the adequacy of the system, measured with the EENT, another aspect of security of supply is the flexibility of the system to cope with fast changes in energy output from variable RES. A MOG offers two benefits with respect to system flexibility: an increase in flexibility in operation of the grid and the (partial) levelling out of uncertainties.

Firstly, the MOG would enable larger flexibility in operation than a radial grid topology. This is due to the fact that there are more alternative paths available for the required power flows. This is an advantage for the system operation, as a larger set of alternatives offers better operation opportunities as it would entail an increase in the degrees of freedom for system operators. This enhances the desired flexibility in dealing with outages, maintenance, congestion management and balancing. Furthermore, the use of HVDC also enhances the controllability (and thus flexibility) of the grid. HVDC technologies enable power flows to be steered actively, thereby offering more freedom for system operators. HVDC systems can behave like grid-forming components rather than grid-following components. System operators would be able to use HVDC technologies to support or alleviate the onshore HVAC power system when necessary. As the integration of 90-205 GW of offshore wind into the onshore HVAC power system is no sinecure, the capability to actively steer power flows would probably become necessary. An HVDC MOG would offer this capability.

Secondly, variable RES are less predictable in their behaviour than conventional power plants. This means that their power production will be constantly deviating from the submitted production plan. These deviations would normally require the use of balancing mechanisms such as Frequency Containment Reserve or automatic Frequency Restoration Reserve. The MOG would connect a larger amount 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 less interdependent and more random, enabling the MOG to level out a large portion of these deviations. This improves the business case for OWFs and facilitates the integration of RES into the power system without disturbances. The MOG would thus enable an organic form of imbalance netting of OWFs [46].

7.4.2.1 EVALUATION OF THE KEY PERFORMANCE INDICATOR

As described above, alternative pathways, increased interconnection in the offshore grid and the smoothening of deviations are the main drivers of the flexibility of the grid. To be valued highly for this indicator, a concept must therefore have a high amount of interconnection and redundancy as well as a lot of OWFs connected to each other in one way or another. Therefore, the more alternative pathways the concept has the better flexibility this concept can offer. As can be found in Appendix VIII, the impact of the flexibility is rated medium/high and its likelihood high in the assessment. Therefore, the flexibility of the grid is considered an important benefit of concepts that have more alternative pathways.

For the concepts the values of hybrid interconnection are presented in Table 7-7 below. As can be seen, the NAT concept offers the highest amount of hybrid interconnection and therefore alternative pathways. The HUB concept and EUR concept offer a similar amount, while the BAU concept logically offers none.

Table 7-7 - Hybrid interconnection in GW by 2050 for each of the concepts.

	2050
BAU	0
NAT	29.2
HUB	13.4
EUR	12.6

7.4.3 B8: SECURITY OF SUPPLY - SECURITY

A third aspect of security of supply is the ability of the system to cope with disturbances applied to the system and to what extent the system is able to maintain power quality and stability under these disturbances. As part of the N-1 security criterion that is applied within PROMOTioN, it is assumed that all concepts can adequately cope with disturbances in the system as a consequence of the loss of a component. However, related to power quality and stability, a MOG would have benefits associated with Power Oscillation Damping, provision of synthetic inertia, black-start (assisting) capability, reactive power compensation and active voltage stability support to the onshore HVAC system.

Firstly, a MOG could contribute to Power Oscillation Damping. A key characteristic of the HVAC onshore system is that large regions are coupled electromechanically. This coupling provides advantages, such as more stable grid frequencies, but also disadvantages. The electro-mechanic coupling entails that oscillatory disturbances can spread throughout the system; a local disturbance can have wider impact due to this power system oscillation. As HVDC systems only couple power systems electrically (and not electro-mechanically), HVDC converters behave like Power Oscillation Damping devices and can thus improve power quality.

Secondly, an HVDC MOG could provide synthetic inertia to contribute to a stable grid frequency. With increasing penetration of power electronic devices enabled generation (of which HVDC is part of), the rate of change of frequency (RoCoF) also increases leading to a less stable grid frequency because the system has a lower overall rotational inertia [47]. This development could require further investments in primary frequency control capabilities as well as the provisioning of more system inertia (rotating mass). However, HVDC converters could also provide such functions and could be a major contributor to power system stability [47]. Although it has been shown that the provision of synthetic inertia by HVDC is technically feasible, the use of it still needs to become more mature

and requires further improvement of complex control schemes [48]. HVDC systems have the advantage they can be very responsive and have a higher ramp-up rate than conventional generators or conventional storage systems.

However, an HVDC system in itself does not provide inertia: generation is required to generate inertia. HVDC systems can subsequently transform, transmit and provide this inertia to demand areas when needed. Meshed HVDC systems would thus facilitate the quick transfer of inertia from one supply area to a demand area, but would in itself not provide the inertia. The delivering area would thus encounter a frequency drop as a result of the delivery of inertia to another power system. In that way, the burden of stabilizing a grid frequency can be shared over a larger area using HVDC systems. Current HVDC systems also already support over-frequency support in which they quickly downregulate their power delivery. Another advantage of HVDC systems is that they can be grid-forming rather than grid-following in the operational control and can thus significantly contribute to the stable operation of weak grids.

Thirdly, a MOG could provide black-start (assisting) capability to the onshore grid(s). A black-start facility is needed to be able to start up the power grid after a black-out; the black-start facility needs to provide electricity to other power plants in order to start up. Such black-start capabilities are usually provided by conventional fossil fuel power plants [49]. An HVDC MOG could, however, also provide the necessary electricity to facilitate the start of other power plants and in that way provide black-start (assisting) capabilities. Compared to a radial approach, a MOG would increase the reliability of this service due to an increased capacity credit of offshore wind. Therefore, a MOG could reliably offer this service, whereas a radially developed offshore wind grid would be less capable of doing so. Therefore, the ability to provide black-start (assisting) capabilities is another benefit of a MOG with respect to system stability.

Fourthly, the MOG could offer large-scale reactive power compensation and active voltage stability support. This is due to the large-scale implementation of HVDC converters in a MOG. The power supply characteristics of HVDC converters can be easily adapted 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 also avoids investments in equipment that would have otherwise been necessary for these functions. For example, the reactive power compensation capability of HVDC converters renders the need for shunt capacitor banks void, avoiding investments in that type of equipment.

7.4.3.1 EVALUATION OF THE KEY PERFORMANCE INDICATOR

Additional benefits of the MOG measured under this KPI can be found in the coupling of synchronous areas to have an overall higher access to the restoration and stabilisation capabilities of these areas. It is therefore assumed that a significant amount of interconnection, in particular point-to-point interconnection, influences the evaluation of this KPI. According to the assessment of this KPI, given in Appendix VIII, not all benefits addressed above have a large impact, although their likelihood is assessed to be high. Therefore, it is concluded that the benefits mentioned under this KPI increase when interconnection increases in the MOG.

Similar to the previous KPI, the interconnection capacity for the concepts are given in Table 7-8 below. The NAT concept has a slightly higher overall capacity than the BAU and EUR concept and a significant higher capacity than in the HUB concept. The BAU scenario, however, has the overall highest amount of regular interconnection capacity, thereby offering the highest benefits in this KPI. The HUB concept offers the lowest benefits.

Table 7-8 - Regular, hybrid and total interconnection capacity for each of the concepts in 2050.

		2050
Regular interconnection capacity (GW)	*BAU*	47.1
	NAT	24.2
	HUB	18.3
	EUR	30.1
Hybrid interconnection capacity (GW)	*BAU*	0
	NAT	29.2
	HUB	13.4
	EUR	12.6
Total interconnection capacity (GW)	*BAU*	47.1
	NAT	53.4
	HUB	31.7
	EUR	42.7

7.4.4 B9: SECURITY OF SUPPLY - RESILIENCE

A MOG could increase the resilience of the power system. It would offer an 'overlay' grid on top of the conventional onshore power system and it would make use of a different kind of technology (HVDC vs. HVAC). Both of these features make the overall power system more resilient, since it becomes less dependent on one type of grid or one type of technology. Furthermore, a completely MOG would entail a high degree of decentralization of offshore wind power evacuation and interconnection capacity. This decentralization makes the overall grid less vulnerable to terrorist threats and natural disasters. It also offers the capability of 'islanding' the grid, 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. A highly centralised MOG concept would be more vulnerable to terrorist threats and natural disasters since the impact of such disturbances would be more significant than in case of the decentralised concept.

7.4.4.1 EVALUATION OF THE KEY PERFORMANCE INDICATOR

In the BAU concept, different parts of the grid would be perfectly operational in case disruptions occur in a certain part of the MOG. It is assumed that scoring on this KPI decreases when the concept becomes more centralised: a single disruption in part of the grid could then have a large impact in the overall operation of the grid. This is also the case, albeit with a smaller impact, when more interconnectivity is established and parts of the grid are more optimally scaled. This could lead to generation shedding, as a loss of part of the grid will mean that not all generated wind energy can be evacuated. In the assessment in Appendix VIII, the impact of this benefit is considered low, although its likelihood is quite high. This is mostly due to the frequency of such disturbances on the grid. It must not, however, be completely discarded. It is therefore assumed that a more centralised MOG concept performs worse on this KPI than more distributed MOG concepts. Therefore, the HUB concept offers the least benefits for this KPI, while the other concepts offer the most.

7.4.5 S1: ENVIRONMENTAL IMPACTS

In May 2019, the Intergovernmental Science-Policy Platform on Biodiversity and Ecosystem Services (IPBES) published a summary for policymakers stating that the global pursuit of economic growth significantly alters life on Earth. The report concludes that 75 % of the planet's land surface is significantly altered, 66 % of the ocean area is experiencing increasing and cumulative impacts, over 85 % of wetlands area has been lost and approximately half the live coral cover on coral reefs has been lost since the 1870s with accelerating losses in recent decades.

The report raises awareness that about one in eight of the planet's plants, insects and animals are at risk of extinction because of human activity, many within decades. It is highlighted that biodiversity is 'declining faster than at any time in human history'. By 2016, 559 of the 6190 domesticated breeds of mammals used for food and agriculture had become extinct and 1,000 more are threatened. The report highlights the direct drivers of change in nature with the largest global impact, being in descending order: changes in land and sea use; direct exploitation of organisms; climate change; pollution; and invasion of alien species. For marine ecosystems, direct exploitation of organisms (mainly fishing) has had the largest relative impact, followed by land and sea use change.

The IPBES report adds to a growing consensus of how human activity impacts the environment and life on Earth. Lately there has also been an increased focus on how the energy transition with a rapid growth in renewables may negatively impact land areas and ecosystems, posing a challenging trade-off between climate and nature. The growing consensus increases the importance of conducting a proper analysis of the environmental effects of building an offshore grid in the North Sea. A proper analysis would require detailed information about each individual platform or island, as location is important to define the environmental impact. However, a proper analysis is also considered too detailed for the CBA. This Section therefore aims to give a high-level illustration of the differences between the BAU concept and meshed concepts without taking the specific location of each individual platform or island into account.

7.4.5.1 METHOD

Environmental impact characterises the project's impact on the (local) environment affected by the project. OSPAR guidance [50] states that national and international legislation will likely require an Environmental Impact Assessment (EIA) to be undertaken prior to any OWF project. The construction of a MOG is expected to be covered in a similar manner as OWF projects in international legislation and is hence assessed in the same way with respect to environmental impact in this Section.

An EIA should cover all four aspects of the project's life history: construction, operation, decommissioning and the removal phase. The EIA should be a systematic assessment of a project's likely significant environmental effects. The purpose of the EIA process is to ensure that all the potential effects of a project are fully understood and communicated to relevant stakeholders. As a minimum, the assessment must include a detailed description of:

- Area specific valued ecological components (VECs) and ecological and biological significant areas (EBSAs)
- Environmental stressors/factors
- Overlap/impact analysis between stressors and VECs/EBSAs
- Conclusions in line with a precautionary approach, and an overview of knowledge gaps
- Clear statements of what effect these might have on the certainty by which environmental effects can be predicted.

The area of the PROMOTioN project is in one of the busiest maritime areas in the North East Atlantic; OSPAR Region I (Greater North Sea – shown in Figure 7-20). Region I opens into the Atlantic Ocean to the north and, via the English Channel, to the south-west, and into the Baltic Sea to the east. Depths do not exceed 700m. The seabed is mainly composed of mud, sandy mud, sand and gravel. The variety of marine landscapes is substantial: fjords, estuaries, sandbanks, bays and intertidal mudflats. Major activities in the area include fishing, extraction of sand and gravel and offshore activities related to oil and gas reserves.

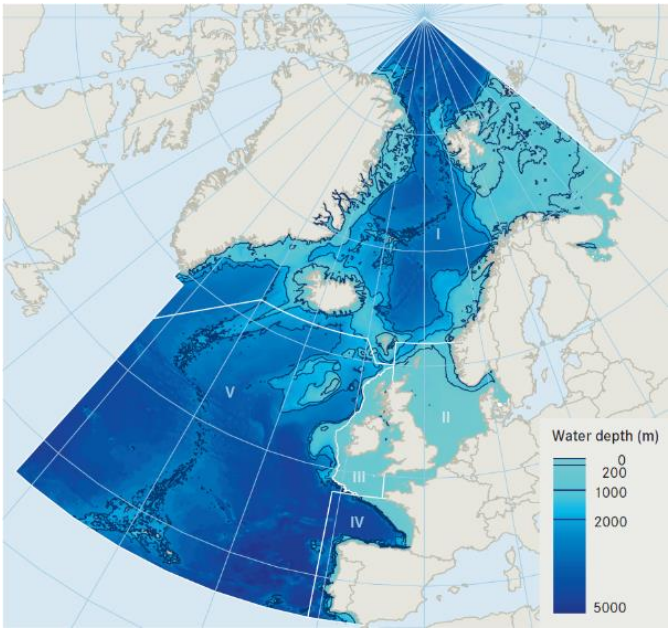


Figure 7-20 - OSPAR Regions. Region I, the Greater North Sea, within the North East Atlantic [51].

Biological systems in the Greater North Sea are rich, complex and highly productive [52]. The Quality Status of Region I, assessing the pressures and threats to the area is described in the OSPAR Greater North Sea Quality Status Report 2010 [51]. According to the International Council for the Exploration of the Sea [53], there are 10 threatened or declining habitat types in the greater North Sea. Threatened or declining species are accounted for by invertebrates (3), seabirds (3), fish (17) and marine mammals (1) [54].

Data obtained regarding environmental value and extent of habitats or species of concern should be used as input to the EIA. Environmental impact on habitats or species should be assessed taking into consideration effects from the various stressors from the different phases, from construction to operation and decommissioning. Based on the individual environmental risk assessments the overall impact from the planned operations should be presented. Depending on expected environmental impact there might be a need for mitigating the environmental impacts and for environmental monitoring and follow up studies during the construction, operation and decommission phases of the projects.

There are different environmental stressors that could be triggered by construction, operation and decommissioning of HVDC installations in the North Sea. These environmental stressors as well as an illustration of what ecological factors/living species they may affect are illustrated in Figure 7-21. These environmental stressors will be further discussed in the analysis of the different concepts.

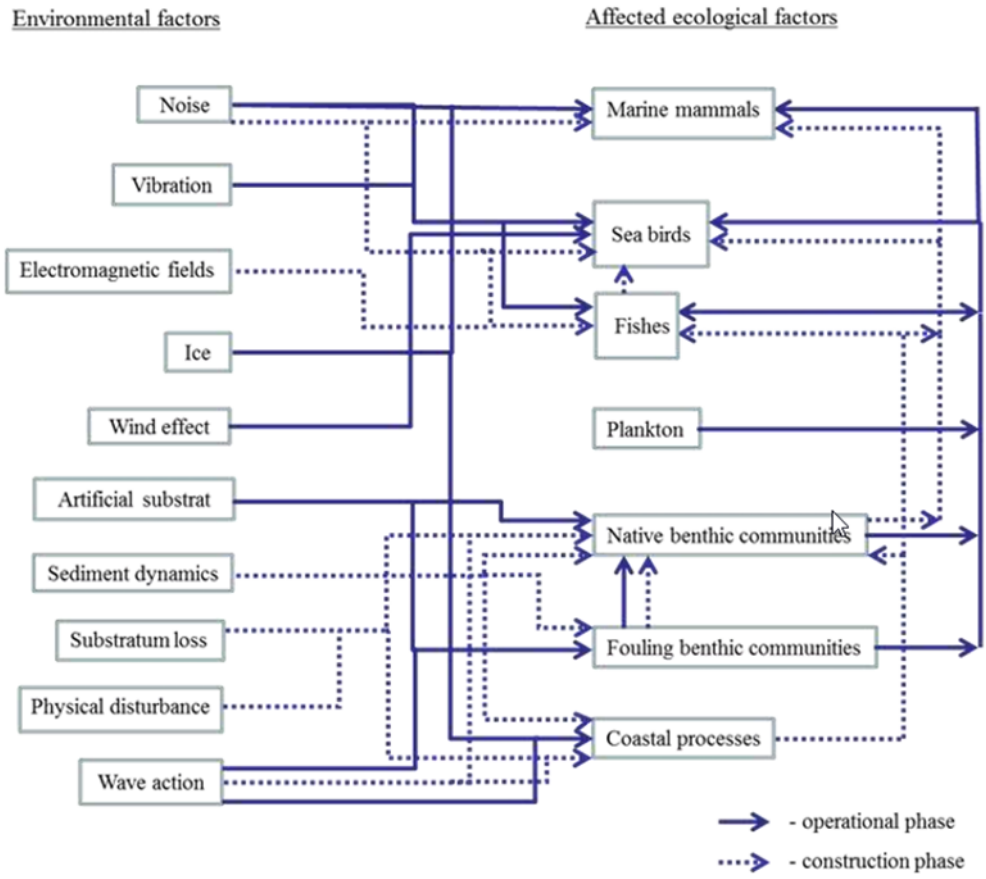


Figure 7-21 - Diagram illustrating possible impact of different stressors related to the operation and construction of offshore wind park to different components of marine ecosystem [2].

The environmental stressors' impact on ecological factors will be affected by the specific locations of the installations. Before planning the establishment of HVDC installations, the suitability of the locations therefore needs to be considered and any potential conflicts with the environment should be documented. An important element of the planning should be to make sure any nature conservation areas, areas of biological or ecological interest or value (e.g. habitats of rare or threatened/red listed species) are avoided. To assess the suitability of e.g. a platform location with respect to the biological features that need to be protected, the relevant basic information (e.g. spatial distribution and temporal variability) should be made available for benthos (epifauna, infauna, macro algae), fish, mammals as well as resident, migratory, resting or feeding birds. Information on critical habitats, such as spawning grounds, breeding, moulting and feeding habitats, and migration routes also needs to be gathered [54].

The described methodology should be used to assess the environmental impact of each island and platform when the specific locations in various cases are known. As the specific locations are not known, it is not possible at this stage to perform detailed EIAs to illustrate the difference in impact in the base case (the BAU concept) and the meshed cases. Below follows a high-level discussion of the environmental differences known at this stage.

7.4.5.2 COMPARISON OF THE BASE CASE AND THE MESHED CASES

Three meshed cases are under development in addition to the base case: Natural Distributed, European Centralised and European Distributed. For simplicity, Natural Distributed and European Distributed are averaged under the name Meshed Distributed[30] in this Section as they are very similar.

The environmental impact from choosing A) base case, B) Meshed Distributed or C) European Centralised is defined by how the installations impact the environmental factors listed in Figure 7-21. How the environmental factors are impacted is in turn influenced by the amount of necessary installations in the different cases. Table 7-9 therefore aims to give an indication of the number of various components in the base case and meshed cases.

Table 7-9 - High level comparison of the base case and the meshed cases in terms of components.

	BASE CASE	**MESHED DISTRIBUTED**	**EUROPEAN CENTRALISED**
Submarine cables (km)	27 500	29 500	25 500
Wind Turbines (unit)[a]	=	=	=
Offshore HVAC Platforms	0	0	0
Offshore HVDC Platforms[b]	135	150	68
Island (power hub)[b]	0	0	6
Onshore Grid (MW)	287 700	248 000	226 900
Onshore Grid (number of stations)	231	185	169

[a] It is assumed that the total amount of offshore wind power will be identical, hence the total number of offshore wind turbines will be the same for the compared cases. In reality it is possible that the MOG might be able to integrate higher amount of offshore wind power due to increased connectivity.

[b] Here the assumption is 2 GW and 22 GW average capacity per platform and island respectively, as is in line with the maximum size of an offshore platform and the average size of the islands in the concepts.

According to Table 7-9, one significant difference between the three cases is related to the trade-off between platforms and islands. In the alternative C) European Centralised, 6 islands replace 67 and 82 platforms compared to A) base case and B) Meshed Distributed case respectively. Approximately one artificial island therefore replaces eleven to thirteen platforms, this ratio agrees well with the power rating ratios of an island (22 GW) and an average platform (2 GW). There is certain level of difference with respect to the total cable length, but this is considered not significant enough to differentiate between the cases. However there are also substantial differences among the three cases in Table 7-9 with respect to the required onshore connection, illustrated both in the total power rating and in the number of landing stations. The assumption is made here that each individual landing station will be designed and constructed reserving prevailing environmental regulation.

[30] This as opposed to the base case, which is also distributed but not meshed.

The difference in total number of landing stations will therefore not result in substantial differences among the three cases.

The difference between the A) base case, B) Meshed Distributed case and C) European Centralised case could hence be simplified to comparing the environmental impact of eleven platforms and one island, where A) base case and B) Meshed Distributed case will be considered analogous for the sake of easier comparison.

An important driver for the environmental impact resulting from eleven platforms and one island is the area occupied by the structures as well as the circumference. A comparison of the area and circumference for eleven platforms and one island is shown below in Table 7-10.

Table 7-10 - Illustrating the difference between eleven platforms and one island.

	ELEVEN PLATFORMS	ONE ISLAND
Power - GW	22 (11x2 GW)	22
Area (top) - m^2	110 000	176 000
Area (bottom) - m^2	110 000	400400
Circumference (top) - m	4400	1490
Circumference (bottom) - m	4400	2243

One important observation from Table 7-10 is that one island will occupy the sea bed with an area four times as large as eleven platforms aggregated and the sea surface with an area 1,6 times as large. Table 7-10 also shows that one island creates a new artificial shoreline (circumference) of 1490 m, while eleven platforms will give a total circumference of 4400 m. The area and circumference will impact the environmental factors in Figure 7-21.

7.4.5.3 DESCRIPTION OF ENVIRONMENTAL FACTORS

The environmental factors as shown in Figure 7-21 are applied to the two cases that are compared, thereby creating an overview of which concepts have higher environmental impacts. In addition to the factors as shown in Figure 7-21, two additional factors are considered: the stepping stones effect (migration of species due to constructed structures) and operational discharges.

7.4.5.3.1 NOISE

The factor captures the noise from eleven platforms and one island in construction-, operation- and decommissioning/removal phases. The impact in the construction phase will be larger for one island than eleven platforms due to the solid seedbed construction for the island. This will also hold true for the operation phase, due to the larger operational area of the island. Decommissioning of the island is not considered, but the impact of noise during decommissioning of platforms is also considered nearly negligible.

7.4.5.3.2 VIBRATION

This factor captures the vibration from eleven platforms and one island in construction-, operation- and decommissioning/removal phases. The impact will be higher for platforms, as the platforms rely on firmly installed legs for stabilisation whereas islands rely mainly on gravity. The seabed drilling activities will be more significant

in the case of platforms in the construction phase. Due to these solid legs, vibration is also considered to be transmitted more easily by platforms than by islands in the operational phase.

7.4.5.3.3 ELECTROMAGNETIC FIELDS

The submarine power cables can emit electromagnetic fields (EMFs) in three ways [55]: the electric field produced by the voltage applied to the cables, the magnetic field produced by current flow on the cable, and an indirect AC electric field induced by alternating magnetic fields or movement within the field, as illustrated in Figure 7-22. In modern power cables, the electric field from voltage applied to the cable are well confined within the cables with the help of metallic sheaths and armouring. However, the magnetic field is only slightly attenuated by the cable wrapping and transmitted well beyond the cable surfaces. There are varying types of evidence to indicate that a subset of marine organisms can detect EMF within the range of frequencies associated with the operation of AC and DC power cables.

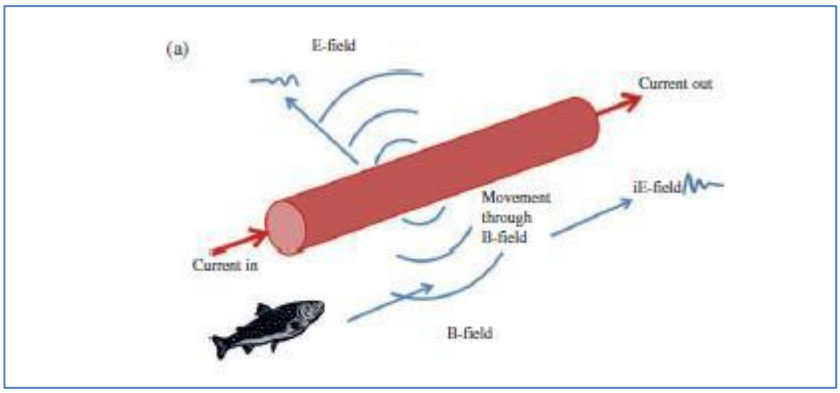


Figure 7-22 - Illustration of Electromagnetic fields emitted from a power cable [55].

Studies including [56] found the EMF characteristics of power cables to be a function of cable design (materials, and cable separation in dual cable designs), voltage, orientation to the Earth's geomagnetic field (DC cables), frequency (AC cables), and burial depth. In general, fields were at a maximum directly above cables and declined rapidly with both vertical and horizontal distance from the cable.

In this analysis, it is assumed that the EMF from the individual cable systems to be well below prevailing environment regulations in the open sea. The challenges are most likely to occur where multiple cable systems are laid in the vicinity of each other and the aggregated EMFs are expected to be substantially higher. The critical interface is around the structure circumference at the seabed, where all power cables are connected to the platforms or island and the cables are placed close to each other, as is illustrated in Figure 7-23.

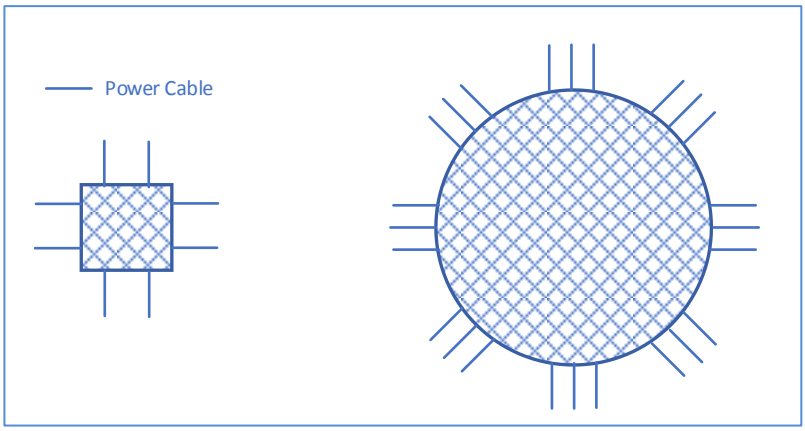


Figure 7-23 - Illustration of power cable interfaces of platform (left) and island (right).

Detailed electrical designs for the platforms and islands are not available and will change substantially from case to case. Therefore, a high-level assessment is adapted where it is assumed that all connected power cables have identical power and voltage ratings and they are distributed evenly around the circumferences. The number of connected cables will therefore be proportional to the total power rating of the platform or island. The concentration level is calculated as the ratio of total power ratings over seabed circumference. The ratio eventually determines how tight the power cables will be placed in the surrounding of the islands and the platforms. EMFs will increase with a higher value for MW per meter of circumference. Following the assumption, the ratio is 5.0 MW/m for platforms and 9.8 MW/m for islands, thus the electromagnetic fields will be higher for islands than platforms.

7.4.5.3.4 WIND EFFECTS

The factor captures the effect eleven platforms and one island will have on wind patterns. Although there will be an effect on wind patterns during the construction phase, this effect is deemed similar for both alternatives. The effect during operation will be higher in the case of platforms as the topside of a platform will be at least 20-30 meters above the sea surface. The island will be not higher than 10 meters above the sea surface and the tallest building should not exceed 30 meters[31].

7.4.5.3.5 ARTIFICIAL SUBSTRATE

This factor captures the amount of artificial substrate created from eleven platforms and one island in construction-, operation- and decommissioning/removal phases. Although there is an impact from both alternatives on this factor during construction, this is assumed to be equal. In the operation phase, there will be differences due to three factors. First, one island will occupy 400400 m^2 of the seabed, compared to 110 000 m^2 for eleven platforms. Second, the island will be a solid structure, while the platform allows water to flow through. Third, an island will create a new artificial shore line with a circumference of 2243 meter while no artificial shore line is created by platforms. The island will therefore be considered to have a higher influence on this factor.

7.4.5.3.6 SEDIMENT DYNAMICS

Sediment dynamics [57] refers to the motion of sediment particles during their formation, transport, and settling processes. Sediment dynamics in coastal and marine environment is an extremely complicated and not fully

[31] The converters on the island will probably be the largest structures on the island, which are approximately 25 meters high.

understood process. Movement of sediment particles is subject to the influence of many environmental factors and processes occurring at different temporal and spatial scales.

The change in the factor is captured by the change in the ocean current from eleven platforms and one island in construction-, operation- and decommissioning/removal phases. The factor will be lager for an island than for eight platforms as islands are bigger and more solid structures than platforms. In addition to the actual structure, the area surrounding the structure will be also impacted. This additional area will also be greater for one island compared to eight platforms. Also, water can flow through the platform structure, implicating less impact on ocean current. This is not the case for islands.

7.4.5.3.7 WAVE ACTIONS

Factor captures the effect of change in wave patterns from eleven platforms and one island in construction-, operation- and decommissioning/removal phases. An island will have a larger effect on wave dynamics as a new shoreline is created. Platforms will not create a new shore line and are therefore assumed to have less impact on wave patterns.

7.4.5.3.8 STEPPING STONES EFFECT FOR INVASIVE SPECIES

The structure provided by platforms and artificial islands offer novel habitat to marine organisms, which may use these sites to spread further to new areas. This is often referred to as the “stepping stones effect”, which is illustrated in Figure 7-24. In the context of the North Seas, multiple offshore structures in relatively close distance to each other will increase the stepping stone effect and hence spreading of invasive species.

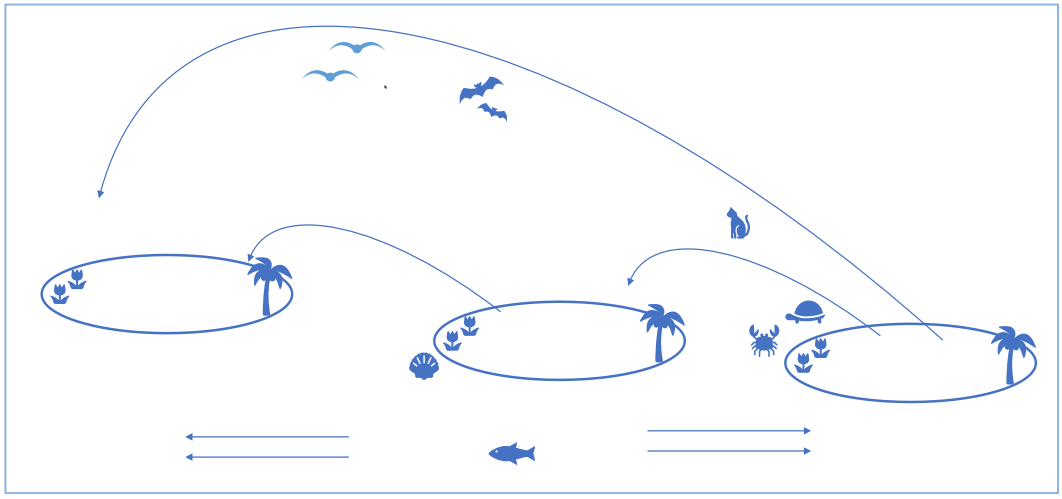


Figure 7-24 - Illustration of stepping stones effects for the spreading of invasive species.

7.4.5.3.9 OPERATIONAL DISCHARGES

This factor captures the effect of operational discharges from eleven platforms and one island in the operation phase. No or negligible operational discharges in the case of platforms, but for islands there will be a more prominently present staff and hence higher operational discharges.

7.4.5.4 EVALUATION OF THE KEY PERFORMANCE INDICATOR

Table 7-11 summarises which environmental factors are impacted during the construction, operation or decommission phases and highlights the anticipated highest overall impact when comparing eleven platforms (P11) and one island (I1).

As shown in Table 7-11, when comparing one artificial island with eleven offshore platforms, the island has more severe impacts on noise, EMFs, artificial substrate, sediment dynamics, wave actions and operational discharges, while the platforms will have a more severe impact on vibration, wind effects and spreading of non-indigenous species. As explained earlier, this conclusion can then be applied when comparing European Centralised base with the base case and Meshed Distributed cases.

It is difficult to give a conclusive comparison on the difference between the base case and meshed cases without knowing the exact location of the different installations. This Section has however identified the main differences between European Centralised case and base case by identifying how environmental factors are impacted in the two cases by simplifying the analysis to a comparison of one island (Centralised case) and eleven platforms (base case and Meshed Distributed cases). The results show that in the construction and operation phase, the European Centralised case will have the most severe impact on noise, electromagnetic field, artificial substrate, sediment dynamics, wave actions and operational discharges, while the base case and Distributed case will have a more severe impact on vibration, wind effects and spreading of non-indigenous species.

Table 7-11 - Possible environmental stressors during construction, operation or decommissioning phases. Bold font, when applicable, indicates anticipated highest overall impact when comparing eleven platforms vs. one island.

ENVIRONMENTAL FACTOR	CONSTRUCTION	OPERATION	DECOMMISSIONING
Noise	P (11), **I (1)**	P (11), **I (1)**	P (11)
Vibration	**P (11)**, I (1)	**P (11)**, I (1)	P (11)
Electromagnetic fields		P (11), **I (1)**	
Wind effects	P (11), I (1)	**P (11)**, I (1)	
Artificial substrate	P (11), I (1)	P (11), **I (1)**	
Sediment dynamics	P (11) , I (1)	P (11), **I (1)**	P (11)
Wave actions	P (11), I (1)	P (11), **I (1)**	
Spreading of non-indigenous species	**P (11),** I (1)	**P (11),** I (1)	
Operational discharges (sewage etc.)		P (11), **I (1)**	

7.4.6 S2: SOCIAL IMPACTS

Social impact characterises the project's impact on the local population affected by the project. Some negative social impact will arise as the project involves investments in the onshore grid where there is local population present. The concept known as 'not in my backyard' is likely to apply; the population supports the project if they

are not being directly influenced by it. The negative effects on the local population will likely be threefold and related to the following:

- **Space consumption**. Increased onshore grid will demand space consumption as landfall area cannot be used for other purposes such as residential, recreational or industry.
- **Visual contamination**. Overhead lines and converter stations will lead to visual contamination onshore. Further, the offshore wind parks might be visible from coastal communities and might alter the physical appearance of the landscape.
- **Negative health effects**. There are still some uncertainties related to the health effects of being close to high voltage equipment. Some people claim they experience negative health effects as result of being exposed to electromagnetic fields over a sustained period.

In addition, some countries may even experience a 'not in my country' type of resistance. Especially in some countries that are blessed with low power prices, there is a fear that more transmission capacity towards other countries will align the power prices in Europe and hence increase the power price in the home country. The fear is not necessarily rational, but politicians may take advantage of it in political campaigns against interconnectors which could postpone investment decisions and/or project execution. The direct effect on the consumers from higher power prices is covered in the CBA in the socio-economic welfare analysis.

To some extent, the project will also have a social impact offshore. Fishing activities may be prohibited in some areas to avoid damage to subsea cables. Navigation may also be impacted by the project, meaning that ships must take alternative routes. The visual contamination as result of platforms and artificial islands will probably be limited as there is no population offshore. It is assumed that offshore workers will not be affected by visual contamination.

In general terms, the social impact of this project will depend on how much equipment that is built, i.e. the number of equipment in each concept, which are repeated in Table 7-12 below for clarity.

Table 7-12 - High level comparison of the base case and the meshed cases in terms of components.

	BASE CASE	MESHED DISTRIBUTED	EUROPEAN CENTRALISED
Submarine cables (km)	27 500	29 500	25 500
Wind Turbines (unit)	=	=	=
Offshore HVAC Platforms	0	0	0
Offshore HVDC Platforms	135	150	68
Island (power hub)	0	0	6
Onshore Grid (MW)	287 700	248 000	226 900
Onshore Grid (number of stations)	231	185	169

As observed in Table 7-12, one major difference between base case and the meshed cases is related to the trade-off between platforms and islands. As the impact on the local population is not significantly influenced, the social impact resulting from this trade-off is hence considered equal in the three different cases.

On the other hand, there are substantial differences among the three cases in Table 7-12 with respect to the required onshore connection, illustrated both in the total power rating and in the number of landing stations. The base case has the highest number of landing stations, whereas European Centralised case has the lowest number of landing stations. The landing stations are normally placed close to the shore area, which in many countries are also densely populated. The negative impact of space consumption and visual contamination will increase with the increasing number of landing stations. Additionally, the total rating of the onshore stations also indicates the rating of the onshore grid reinforcements directly related to the creation of the offshore grid. Although these direct reinforcements are also confined to the coastal areas, this further increases the impacts of space consumption and visual contamination on the same population. In this sense one can conclude that the base case will have worst social impact, whereas the European Centralised case will have the most benign social impact. The Meshed Distributed case will have slightly worse social impact than the European Centralised case but significantly better than the base case.

7.4.7 S3: OTHER

Apart from the benefits included in the adapted CBA-methodology, the development of a MOG could have several other benefits as well. These benefits include the ability for gradual development, support for the European high-tech industry, geopolitical advantages and enhanced European integration. Like other benefits, these are extremely difficult to quantify. Instead, these offer additional benefits to the concepts, rather than decisive benefits.

In comparison with the large-scale centralised concept, a distributed MOG would be constructed with a more incremental and gradual development of smaller sub-sections of the grid. This modular construction approach entails lower upfront investments costs. This enhances the attractiveness of the project, since lower upfront investment costs decreases the risks associated to such investments. This decrease in risks would also lead to lower financing costs, since it would translate into lower interest rates compared to the more risky centralised project. The modular approach of a MOG thus entails that it will not have to be built at once, but rather over a longer period of time. Apart from the decrease in risk, this also leads to easier financing because lower amounts of capital need to be provided at a single point in time. As the provision of large amounts of capital would be difficult and expensive in itself, this is another advantage of a more distributed MOG.

Secondly, the development of a MOG would also offer support for the European (high-tech) industry. The MOG would require large amounts of HVDC cables as well as HVDC converters. Important manufacturers of HVDC equipment include ABB, Siemens and Alstom (converter suppliers) and Nexans and Prysmian (cable suppliers). These are all European companies that compete on a global level with manufacturers such as General Electric, Mitsubishi and Hitachi [58]. The development of a MOG could thus offer important support to European manufacturers active in the high-tech industry. This would increase competitiveness and research & development initiatives employed in Europe, as well as provide a large amount of jobs for the development, construction and operation of the MOG. The support for the European high-tech industry could also result in lower cost prices of HVDC equipment because of the positive incentives for research & development.

Thirdly, the development of the MOG would offer geopolitical advantages. The increase in the capacity credit due to the MOG would decrease the dependence on fossil fuels and thus the geopolitical dependence on the supply of fossil fuels from non-European countries. As energy dependence has been an important geopolitical factor for a long period of time already, this provides an important argument for the development of a MOG. Furthermore, the development of the grid could support the European industry (see preceding paragraph). This would result in

an important security advantage, since European equipment could be used for critical offshore and onshore infrastructure. Given increasing cyber security concerns, this would offer another advantage of the development of the European offshore grid.

Finally, the MOG would be another example as well as another catalyser for further European integration. The grid can only be constructed if there would be large-scale cooperation between different European countries. It would require significant amounts of coordination efforts to align the European Union, European countries, Transmission System Operators, investors, manufacturers and other stakeholders in order for them to cooperate effectively on the development of the offshore grid. By doing so, the offshore grid would be another example of far-reaching European integration. It is not unlikely that this enhanced integration can have 'spill-over' effects and lead to other beneficial developments. In that way, the offshore grid could serve as a catalyser for enhanced European integration. The offshore grid would also contribute to a better functioning internal market (socio-economic welfare) and the price convergence leads to a more equal playing-field for power producers and more equal electricity prices for consumers. This enhances the functioning and societal and political support for the European internal market and hence the European Union.

8 COST-BENEFIT ANALYSIS OF THE TOPOLOGIES

8.1 SUMMARY OF THE CHAPTER

To understand the economic and social consequences of undertaking the development of an offshore grid in a particular region, it was necessary to perform a CBA to assess the costs and value of the MOG to society. However, the CBA does not merely involve the calculation of costs and benefits of each concept. For each concept there are differences in costs and benefits, but there is of course also the question how these costs weigh up against the benefits.

Although quite a number of benefits have been quantified, this is not always expressed in monetary terms. As such, the analysis cannot be done only on an economical basis. Instead, this Chapter aims to provide a comprehensive overview of the costs and benefits as presented in previous Chapters, refraining from assigning value to each and thus also electing a 'best' concept. To do so, first an economic evaluation of the concepts is carried out in order to be able to compare the costs of the concepts. Afterwards, an overview of these costs and the benefits, both quantified and qualified, is given.

8.2 INTRODUCTION

The following chapter is a combination of the results from Chapter 6 and Chapter 7. In Chapter 6, the results of the cost analysis was given for each of the concepts under each of the wind scenarios in Section 6.4.1 and Appendix VI. This was done for two KPIs - C1: CAPEX and C2: OPEX. For both these KPIs, the cumulative figure was given for the entire period, for all different wind scenarios. These figures are used in this Chapter.

For each of the benefit KPIs that were quantified, the results as were presented in 7.3.4 and Appendix VII are aggregated and displayed. In describing the qualitative benefits, a distinction was made between concepts where it was apparent a distinction was possible (e.g. environmental impacts). These benefits are also valued in comparison with each other by giving their relative impact. If no distinction was possible, the benefits were counted for all concepts. Whether or not a distinction was possible is based on the analysis performed in Section 7.4.

8.3 EVALUTION OF FINAL TOPOLOGIES

An overview of the costs and benefits is presented below in Table 8-1 for the qualitative KPIs and Table 8-2 for the qualitative KIPs. In terms of CAPEX and 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 amount of HVDC platforms displaced by the artificial islands is too low to create a cost advantage. This is further described in Section 6.4.4. The NAT and EUR concepts have higher CAPEX and OPEX costs than BAU. This is due to the fact that the reduction in cable length is only minor. However, the additional protection system costs increase due to the meshing of the grid. This has a large influence on the grid. A more in-depth analysis of this influence is given in Section 6.4.3. Note that the CAPEX and OPEX figures have a 30 % uncertainty.

All concepts show some benefits compared to BAU, although some of the concepts score worse. For example, the HUB concept scores worse in all three wind scenarios on B2: RES integration. As one of the main conclusions of the benefit analysis is that the ability of the system to fully utilise its potential lacks. The installed capacity of

hydro-pump storage is not sufficient anymore as the only storage option available and thus more flexible options should be considered. These could be, with the current research status in mind, either battery storage or power-to-X. Raising the capacity on strategic interconnectors could also be possibility, such as between Germany, Austria and Switzerland or Germany, Denmark and Norway.

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

Table 8-1 - Overview of quantitative costs and benefits of the concepts. Note: B4 and B5 are not evaluated.

Key Performance Indicator	Concept	Cost or benefit			Unit
		High wind scenario	Central wind scenario	Low wind scenario	
C1: CAPEX	*BAU*	186.60	121.20	74.80	bn€
	NAT	194.90	125.30	74.10	
	HUB	171.90	114.80	74.10	
	EUR	200.70	130.00	75.10	
C2: OPEX	*BAU*	54.50	36.30	23.40	bn€
	NAT	56.70	38.30	23.20	
	HUB	52.20	35.90	24.30	
	EUR	59.30	39.70	23.80	
B1: Socio-economic welfare	*BAU*	-	-	-	bn€
	NAT	10.37	0.71	3.62	
	HUB	7.62	-6.72	2.14	
	EUR	0.07	1.03	4.93	
B2: Renewable Energy Sources (RES) integration	*BAU*	0	0	0	MWh
	NAT	83,300,000	600,000	-4,700,000	
	HUB	-235,900,000	-139,800,000	-41,200,000	
	EUR	77,800,000	10,500,000	-5,700,000	
B3: Variation in CO_2-emissions	*BAU*	0	0	0	t
	NAT	41,000,000	10,000,000	26,300,000	
	HUB	22,700,000	-61,600,000	15,900,000	
	EUR	6,300,000	-17,100,000	25,500,000	
B6: Security of supply: Adequacy to meet demand	*BAU*	0	0	0	MWh
	NAT	720,000	0	470,000	
	HUB	630,000	0	480,000	
	EUR	720,000	0	90,000	

Table 8-2 - Overview of qualitative costs and benefits of the concepts. Note: B4 and B5 are not evaluated.

KEY PERFORMANCE INDICATOR	CONCEPT	COST OR BENEFIT	IMPACT
B7: Security of supply: System flexibility	*BAU*	Increased flexibility in operation and levelling out uncertainties and variations in wind production.	None
	NAT		High
	HUB		Medium
	EUR		Medium
B8: Security of supply: System stability (security)	*BAU*	Improved power oscillation damping, provision of synthetic inertia and black-start (assisting) capabilities and reactive power compensation and active voltage stability support	High
	NAT		Medium
	HUB		Low
	EUR		Medium

KEY PERFORMANCE INDICATOR	CONCEPT	COST OR BENEFIT	IMPACT
B9: Security of supply: resilience	*BAU*	Increase in resilience of power system	High
	NAT		High
	HUB		Low
	EUR		High
S1: Environmental impacts	*BAU*	Effects of the concepts are described according to their impact on environmental factors.	Vibration, wind effects and spreading of non-indigenous species
	NAT		Vibration, wind effects and spreading of non-indigenous species
	HUB		Noise, EMFs, artificial substrate, sediment dynamics, wave actions and operational discharges
	EUR		Vibration, wind effects and spreading of non-indigenous species
S2: Social impacts	*BAU*	Space consumption, visual contamination and negative health effects	High
	NAT		Medium/low
	HUB		Low
	EUR		Medium/low
S3: Other	All	Possibility of gradual development	High
	All	Support for European industry	High
	All	Geopolitical advantages	High
	All	Increased European integration	High

9 DISCUSSION

9.1 SUMMARY OF THE CHAPTER

During the PROMOTioN project, several aspects that are of interest to the research were discovered. Although many of these have been taken into account, several were left out of scope. As with any research, not all aspects could be taken into account due to their increased complexity, required preceding research or simple finance or manpower constraints. Therefore, several aspects for further research are suggested in this Chapter. This includes the impact of the offshore grid on the onshore grid, the use of flexibilities in the grid and the development of technologies over time. Finally, the interpretation of results is discussed.

9.2 ONSHORE GRID

As a first suggestion is the research into the integration of the offshore grid and the onshore grid that is not considered within the project. Only the direct near-shore onshore grid reinforcements are captured in the CBA by assuming the reinforcement of existing onshore connection points with converters and transformers. However, this will not be sufficient in reality. Bringing the amount of wind energy to shore as is imagined within the PROMOTioN project would require several more adaptations to the onshore grid as well.

First, the lines originating from the onshore connection point will have to be reinforced, as these are simply not capable of transporting the additional power. However, these may not have to be scaled up with the exact same capacity as is brought to shore by the offshore grid. The onshore connection points are currently existing substations and are therefore intended already for the distribution of energy generated onshore. With the increase in offshore wind capacity, but certainly also the onshore renewable energy generation, incoming connections to these substations might in turn become obsolete, as these currently connect non-renewable generation to these substations. Factoring in distributed energy storage onshore would even add another impact on the substations, completely altering the onshore grid. It is for these reasons of additional complexity that the onshore grid was not considered within PROMOTioN.

Secondly, from these onshore substations the energy will have to be transported to the areas where the demand is located. This may require the reinforcement of existing substations or even the establishment of new substations further inland, also again possibly requiring the increase in capacity of exiting circuits. Especially relevant would be research into the transportation of offshore wind energy directly to 'centres of consumption'; areas where energy consumption is particularly high and renewable energy generation is still low. For example, the German Ruhr area could be such an area, which is located in the south-west of Germany, close to the border with the Netherlands and thus far away from shore. Taking into account demand areas could even potentially influence the development of the offshore grid, as then the entire route from offshore generation to onshore consumption will have to be considered. This could mean a route with a longer offshore section but shorter onshore section is economically more optimal, thereby affecting the topology generation. The influence of not taking into account energy demand in the development of the topologies can already be clearly seen in the benefit calculation, where the curtailment is higher in the topologies which are better optimised to evacuate wind to shore. If the demand centres would be taken into account, the topologies would be influenced by this.

Thirdly, as consumption and onshore area competition increases, onshore grids might reach reinforcement costs that become far too unfavourable for consumers. Creating additional pathways offshore might then even become

an option, utilising the established offshore grid. This would again influence the generation of the topologies, even potentially creating additional value for offshore wind areas that are now deemed unfavourable in the current research.

Fourthly, it was suggested by WP2 that more research was needed 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.

Research into the onshore grids would therefore definitely add value to the research into the offshore grids. However, such a research requires a tremendous effort that was considered infeasible within the original scope of PROMOTioN. In order to properly carry out such a research, the onshore grids of the North Seas countries would have to be modelled in detail, also adding assumptions on the development of this onshore grid into the model. 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. A research that large would necessitate a multitude of the current project´s consortium members, thereby making it an infeasible research to be carried out within PROMOTioN. It is recommended, however, to further explore the synergies between the modelling of an offshore grid and the modelling of an onshore grid. For applications in reality, it is recommended to coordinate the offshore development and the onshore development simultaneously. Especially considering the amount of coordination necessary to establish large artificial islands or meshing of the grid offshore, such coordination should also be applied in expansion of the onshore grid.

9.3 FLEXIBILITIES

Not completely unrelated to the previous Section is the possibility to add power to gas or technologies such as batteries as a means of electricity storage offshore. Within the research it is considered that all energy that is generated by the OWFs will have to be directly transported to shore and used onshore. This means that at times of full production, the cables to shore will have to be capable of transporting this energy to shore. Additionally, as described in the previous Section, this also entails the reinforcement of the onshore grid to a similar extent. As wind power tends to fluctuate throughout time, this may seem unlikely to be optimal. Power to gas facilities or other flexibilities would be able to exploit these fluctuations of wind energy generation to store energy at times of high energy production and release this energy at times of low energy production. This does not only entail the better utilisation of the cable connections to shore, which can then be scaled more optimally, this also adds value to the operation of the onshore grid, as then wind energy would be a far more stable energy supply[32]. Especially a large centralised concept such as the HUB concept could benefit from flexibilities, as the wind energy is already collected in a central point and distributed from there. This means that an offshore flexibility facility could be of a large scale and provide its benefits for a lot of capacity at once.

Flexibilities onshore could also be a viable option in the future for similar reasons. Additionally, power to gas facilities onshore could be beneficial for the industry, where the gases could be further used for production when these are not necessary for energy generation. This could increase the flexibility of the power to gas facilities. This would not impact the offshore grid as directly as the offshore flexibilities, other than that this could cause the

[32] 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.

use of higher rated equipment that would currently defy the N-1 security criterion used within PROMOTioN. This means corridors of large capacity could be connected to a single onshore station, where flexibilities are situated to provide back-up when necessary.

Flexibilities, both on and offshore, would also be an answer to the high curtailment in the HUB and EUR concepts, as the generated wind energy that would otherwise have to be curtailed could be then be stored for later use. However, currently power to gas and other flexibility options are an immature technology and full-scale tests are limited to a very small capacity. The impact of flexibilities on the offshore grid is therefore assumed to be bounded only to later stages of offshore grid development. The high uncertainties in the costs and the development of the technology have are the reason for PROMOTioN to be unable to take into account the use of the technology in the project. However, if research into the technology produces more favourable and more tangible results, the technology is considered promising for the aforementioned reasons.

9.4 TECHNOLOGIES

Apart from the progress made within PROMOTioN on the technologies used in the offshore grid, further progress of the development of technologies is not assumed. Components will be produced on a large scale when the offshore grid develops towards tens or hundreds of GW and will therefore improve significantly throughout the periods. Generally, components may become more efficient which has its impacts on the total energy transported throughout the grid. Also, components may become of a smaller size, which has large impacts on the total costs of the components. Although some cost developments are taken into account in the CBA, these factors are not.

Additionally, components of a larger size or different configuration have not been taken into account. The current limiting capacity of a converter and cables is 2 GW. However, the reference incident for mainland Europe is 3 GW. Even within the currently defined limits of PROMOTioN, converters and cables of 3 GW could be an option when they become available. Taking into account onshore flexibilities, these could even develop further into higher capacities. Also not taken into account are certain technologies that might seem more unconventional, such as overhead DC lines offshore.

Within PROMOTioN, however, it has been decided to conduct the research with currently available, or nearly available, technologies that are applied nowadays. The HVDC market is a quite competitive market which is still much under development. Therefore, information on the development of current technologies or new development of technologies is not (publically) available. Any data linked to this carries large uncertainties, which impacts the ability to conduct proper research. Especially where new technologies are concerned, the demonstration of these technologies is still required before practical application may occur.

Further progress will also have to be made concerning the standardisation of the technologies. The topologies are generated technology-agnostic; that is, a DC platform will host *an* AC/DC converter. More correctly, however, a DC platform will have to host an AC/DC converter with specific characteristics according to specific standards in order for the other components of the grid to be able to work with this converter and communicate with it. According to WP4, this specifically is a problem with DCCBs and converters. However, interoperability between components is usually not an issue when components are made by the same manufacturer, but might lead to problems between different manufacturers. Standards will therefore have to be defined for the technologies in the grid. Any open interpretation of these standards may lead to issues with components operating with each other. Therefore, standardisation of the technologies will have to be carefully done with specific research into the technologies and their standards. WP11 is involved in mapping the groups that require harmonisation of standards and the analysis of contributions from PROMOTioN to these standards. Several topics where

standardisation may be required that are not dealt with in PROMOTioN will be passed on the relevant harmonisation bodies by the end of the project to further advance the standardisation outside the project.

9.5 RESULTS

The results that are given in PROMOTioN add much to the current knowledge of HVDC offshore grids, even without the aforementioned aspects. As was discussed in Section 2.2, the PROMOTioN project is one of the first projects that incorporates many aspects of offshore grids into a single project, thereby also progressing the technologies that are used within the research. This has a direct effect in the application of these technologies and the progress of these technologies from a concept to an existing technology.

However, the pioneering character of PROMOTioN has its drawbacks, as was already discussed in the preceding Sections of this Chapter. Although the PROMOTioN project brings together theoretical research and practical application, its theoretical basis is still very much prevalent within the research and therefore the results. Aspects that were mentioned in the previous Sections would improve this practical nature of the research, but the theoretical basis cannot be neglected. Therefore, it was considered to bring in as much practical research where possible, but this is not always considered feasible. Especially in a project where the time horizon within the research is towards several decades in the future, the theoretical basis will remain strong.

PROMOTioN never set out to predict the future. The project has always aimed to describe possible routes towards offshore wind and corresponding grid development, without it claiming to model the truth. This means that the offshore grid will probably never have the exact characteristics of the concepts, as was already described in Chapter 4. Any actual offshore grid topology will more likely be a combination of the concepts. This is already seen in the topologies, where large sections of the offshore grid remain to be connected radially instead of through meshing, or through central hubs. The results for each of the concepts will therefore also not become reality. This, as stated, was never the intention of PROMOTioN. The purpose of the concepts was to show the differences in the approaches to constructing an offshore grid so that recommendations can be distilled from this. Several recommendations have already been stated in the preceding Sections and these are also brought into Deliverable 12.4.

10 CONCLUSIONS

As was stated in the introduction of the document, the purpose of this Deliverable was to give insight into the development of the concepts and development scenarios that are used in the analysis of the potential for offshore wind in the North Seas. As each of the concepts represents different challenges as well as different design philosophies, it was deemed important to assess the costs and benefits of each concept. For this, the PROMOTioN CBA methodology was applied, as was described in Deliverable 7.11. This Deliverable started with detailing the need for a CBA and the approach to assessing different grid concepts. For this, first the offshore wind generation scenarios were constructed, which first constructed three macro-scenarios for the North Seas, which were in line with existing scenarios for offshore wind. The wind energy generation potential was then allocated to the different North Seas countries, aligned with the available space in the EEZ and peak load. These country allocations were then translated into specific projects, where the available offshore space for each country was identified and ranked in favourability according to multiple exclusion and selection criteria.

After the construction of the offshore wind generation scenarios, the four concepts were introduced that were then imposed on the scenarios to create the topologies. In the definition of the concepts several extremes were identified, each being defined along two axes; that of cooperation and complexity. The concept that requires the least cooperation and is the least complex is the BAU concept, where each individual country develops its offshore wind energy separately, thereby requiring little cooperation. The complexity is also limited as it is assumed that point-to-point connections as those are known nowadays will continue to be constructed in the North Seas. The concept that requires little cooperation but already has a higher complexity is the NAT concept, where offshore grids are primarily constructed for each country to generate its own offshore wind energy and transport this to shore. If deemed appropriate, meshing is possible in this concept, thereby increasing the complexity. Little cooperation is required in this concept, only in order to establish hybrid interconnection where this is beneficial. The concept that requires tremendous cooperation between the North Seas countries but is not necessarily technologically complex is the HUB concept, where large artificial islands may be constructed instead of DC platforms. Finally, a cooperation intensive and highly complex concept is imagined in the EUR concept, where the grid can develop freely without any constraints that influence the development. From the concept definition it was concluded that there were low risks of lock-in into any concept that was defined. The highest risks are assumed to be the anticipatory investments that are necessary in NAT, HUB and EUR concepts, where that of the HUB has the highest risk of stranded assets in case of a change of grid development towards another concept.

Combining the scenarios and the concepts resulted in the topologies. The topology generation methodology combined optimisation of the cable length and use of a market model to take into consideration costs but also benefits of cross-border interconnection via the MOG. A dedicated optimisation tool has been used for the sake of the study in order to determine the least-cost topology able to evacuate the installed offshore wind capacity. In addition, a market model based on the TYNDP dataset has been implemented in order to determine the most economic investments to reinforce interconnections between the North Sea countries.

The costs of the topologies could then be estimated, which was done by processing the topologies into a costing model. This costing model included a decision-making process where the optimal choice for components was made according to specific criteria. It was shown in the costing of the topologies that most noticeably the HUB concept had significantly lower costs. Additionally, meshing of the grid resulted in lower cable costs due to a

reduction in cable length. However, it was also shown in the cost calculation that these cable cost reductions are easily nullified by the introduction of a protection system into the structures.

From the analyses presented in this document, several conclusions can be drawn. These conclusions concern three major grid configurations that were applied in the concepts: point-to-point evacuation of wind energy, meshing and the application of artificial islands.

The proposed point-to-point connection remains a competitive option and is the first building block for each topology. The topology generation shows a significant amount of 2 GW OWFs in each of the topologies[33].

- 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 recommended to steer to standardising a 2 GW 525kV platform and converter design to be applied throughout the North Seas.
- It is recommended to coordinate maritime spatial planning as this is key to reach 2 GW by “aggregating” windfarms to be connected to a single offshore AC/DC converter. This allows the application of a standardised 2 GW concept. 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 requires around 200-400 km^2 which appears realistic from the GIS study and allows AC connections to an offshore HVDC platform. AC connections from the windfarm in 66 kV carry a cost reduction and it is therefore recommended to apply this into the 2 GW concept.

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

- The combined use of the offshore grid for wind evacuation and interconnectors is an important driver for meshing/multi-terminal. It is therefore recommended to apply hybrid interconnection in cases where this is optimal i.e. when two OWFs are in close vicinity to each other.
- Reduction in cable length from one concept to another is sensitive on input assumptions. Depending on the assumptions, the difference is very significant or not. If the difference is small, the costs of other aspects (such as protection devices, platforms, advanced controls) have to be considered. It is therefore recommended to apply meshing in areas where there is a large reduction of cable length if aspects like protection devices play a role.
- The Dogger Bank seems an ideal candidate to form a backbone because of the short distances between OWFs. There are no clear benefits to connect all the multi-terminal structures together to form a single grid (meaning extra-costs and complexity). Therefore, it is recommended to apply meshing only when this leads to a decrease in cable length.
- Increasing onshore hosting capacity reduces significantly the total cable length required for all concepts but is more beneficial for the NAT, EUR and HUB concepts. Additionally, in the benefit analysis in the High wind scenario, it was shown that an increase in coordination offshore leads to a counterintuitive increase of offshore wind energy curtailment. This is because in these topologies not all wind energy that would be transported to land would then be able to be transported to the areas where it is required. For these reasons is recommended to take into account the capacity of the onshore grid in planning the

[33] Due to this, these recommendations are steered towards a 2 GW 525kV HVDC concept, but these recommendations are valid for other sizes as well.

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.

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

The HUB concept shows that artificial islands in places where there is high wind energy generation density can significantly reduce costs.

- Although not further studied within PROMOTioN, there is a maximum distance at which connection to an artificial island is economically sensible. This distance is not fixed and is influenced by multiple factors, including the position of the OWF relative to the island and the onshore connection point, the combined evacuation of energy generated by multiple OWFs, the existence of flexibility on the island and the interconnection capacity on the island. It is recommended for artificial islands to be planned along with the establishment of multiple OWFs, as these factors are also influenced by the presence of other OWFs[34].
- The artificial islands in the HUB concept are considered to be only replacements of offshore DC platforms, without the AC/DC converters being permanently linked. Whether or not the artificial islands could be connected on the DC side (e.g. with a ring-like DC busbar) has not been studied within PROMOTioN but could be an option for these islands. This would allow for more efficient transportation of wind energy, without converter losses, and the possibility to better control and direct power flow, but then could also require a protection system. It is therefore recommended to further study potential designs of the artificial islands, thereby including different interconnection options of the converters and the option of flexibilities on the island.

[34] 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.

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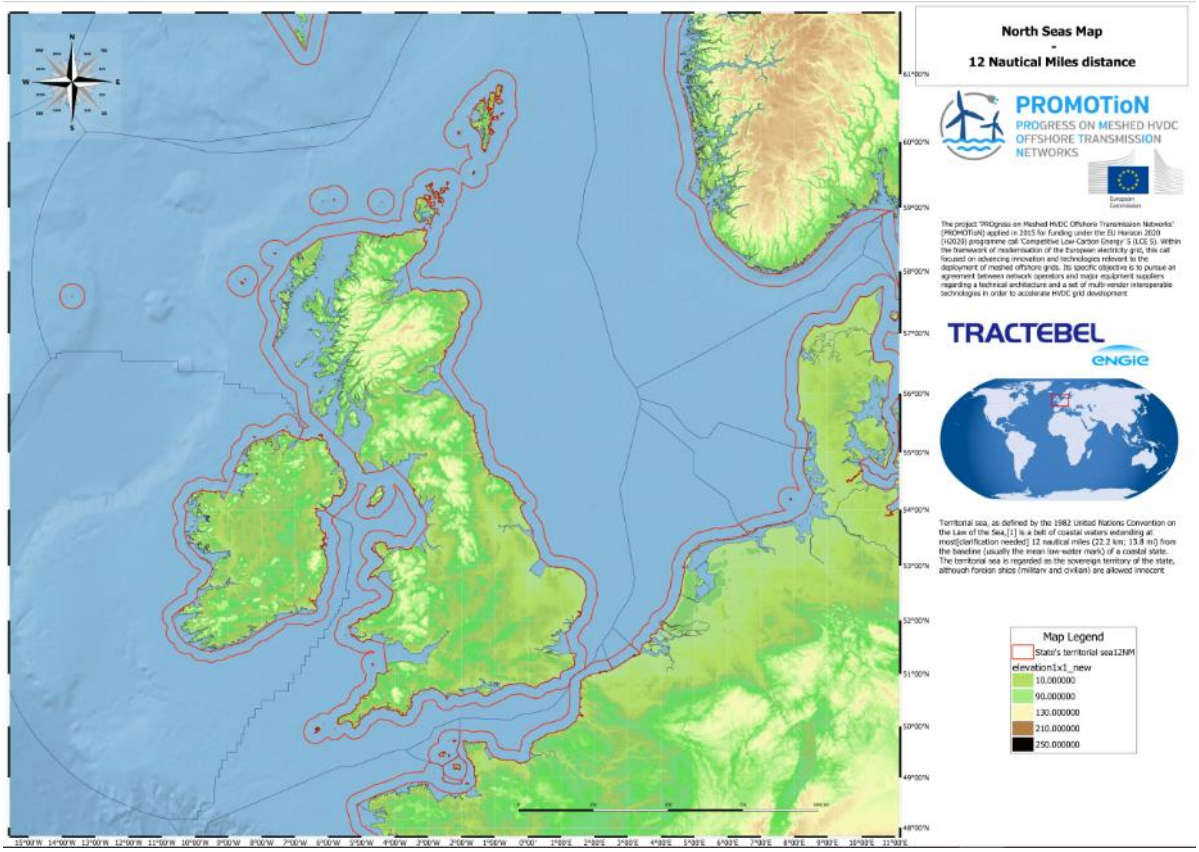
APPENDIX I

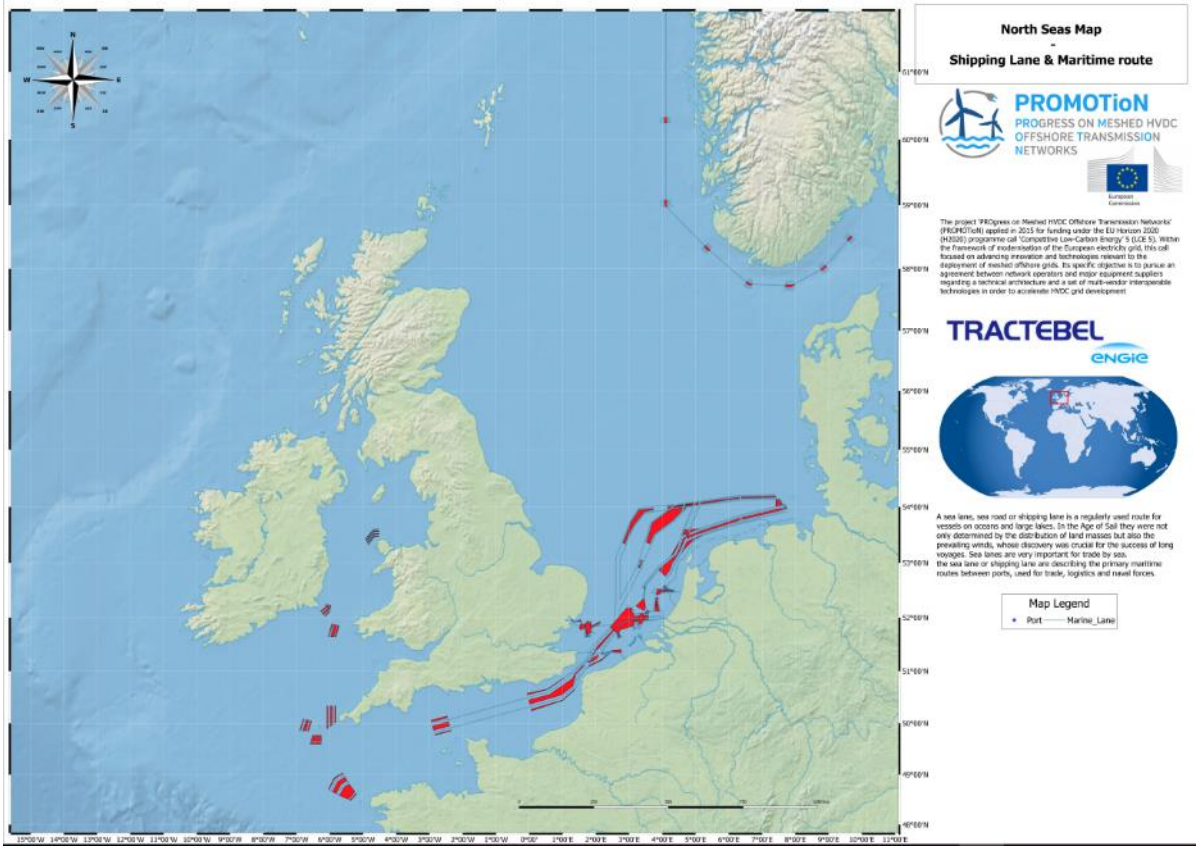
ADDITIONAL DETAILS ON THE OFFSHORE WIND GENERATION SCENARIOS

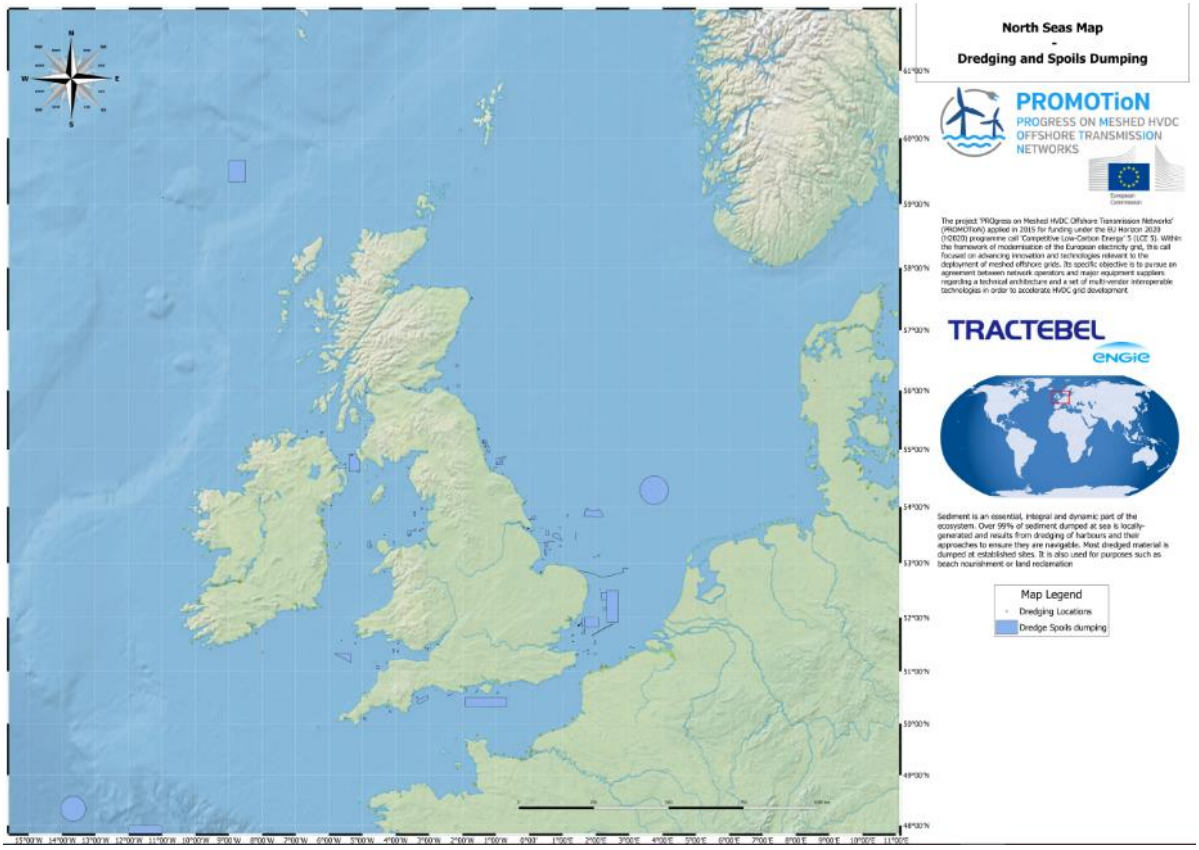
This appendix gives additional details on different aspects of the methodology followed to develop the offshore wind generation scenarios, as well as on the corresponding results.

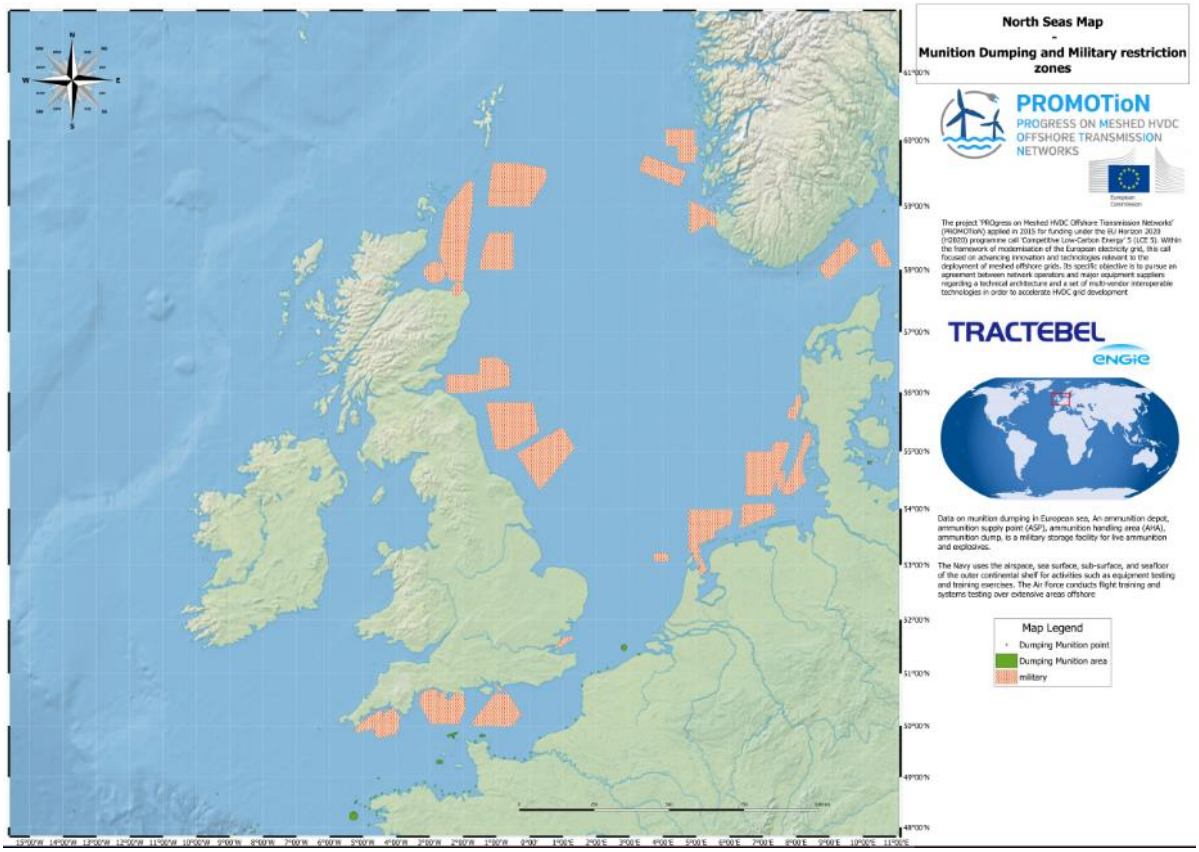
EXCLUSION CRITERIA

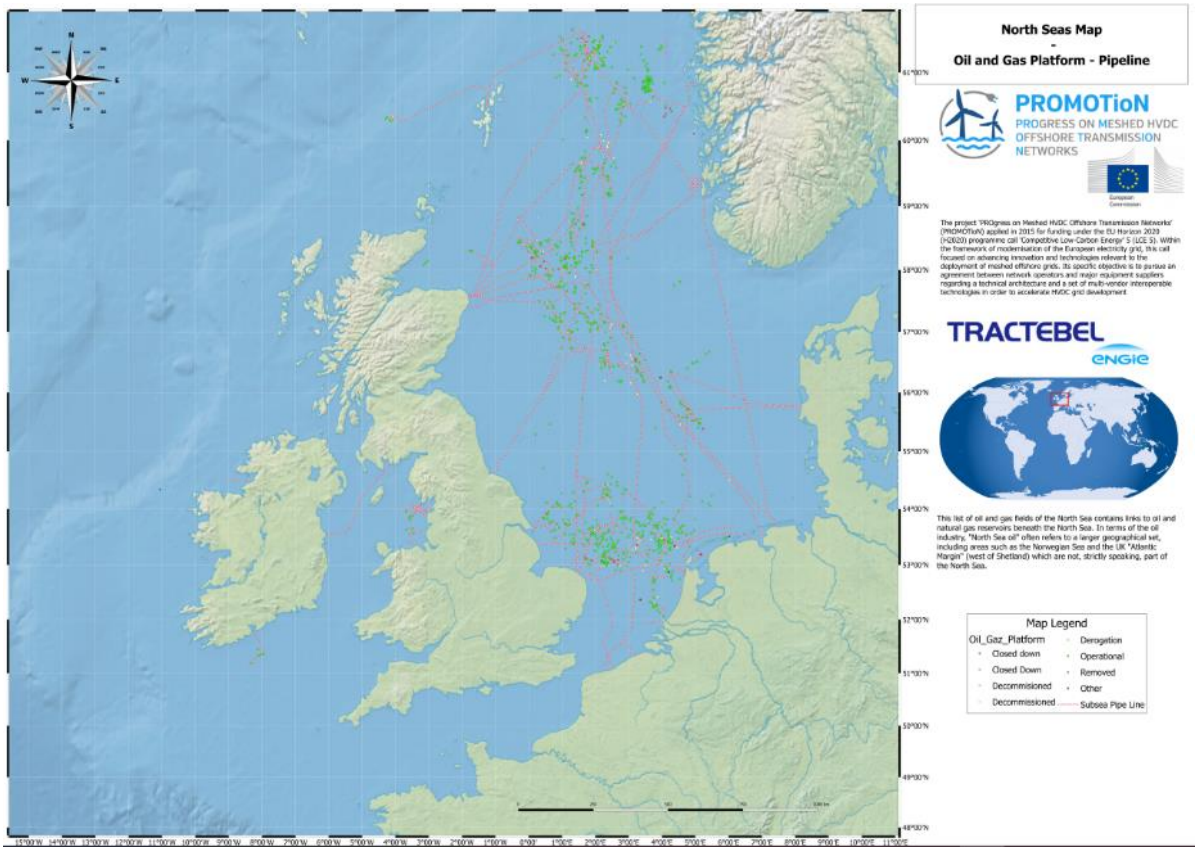
In order to illustrate Section 3.4.2, the following maps show for the North Seas the 12 nautical miles distance to the coast, the traffic lanes, the dredging & dumping areas, the military exercise areas, the oil & gas pipelines and drilling areas, the fishing intensity areas, the ferry routes & ports, the telecom cables and landing points, and the subsea transport cables.

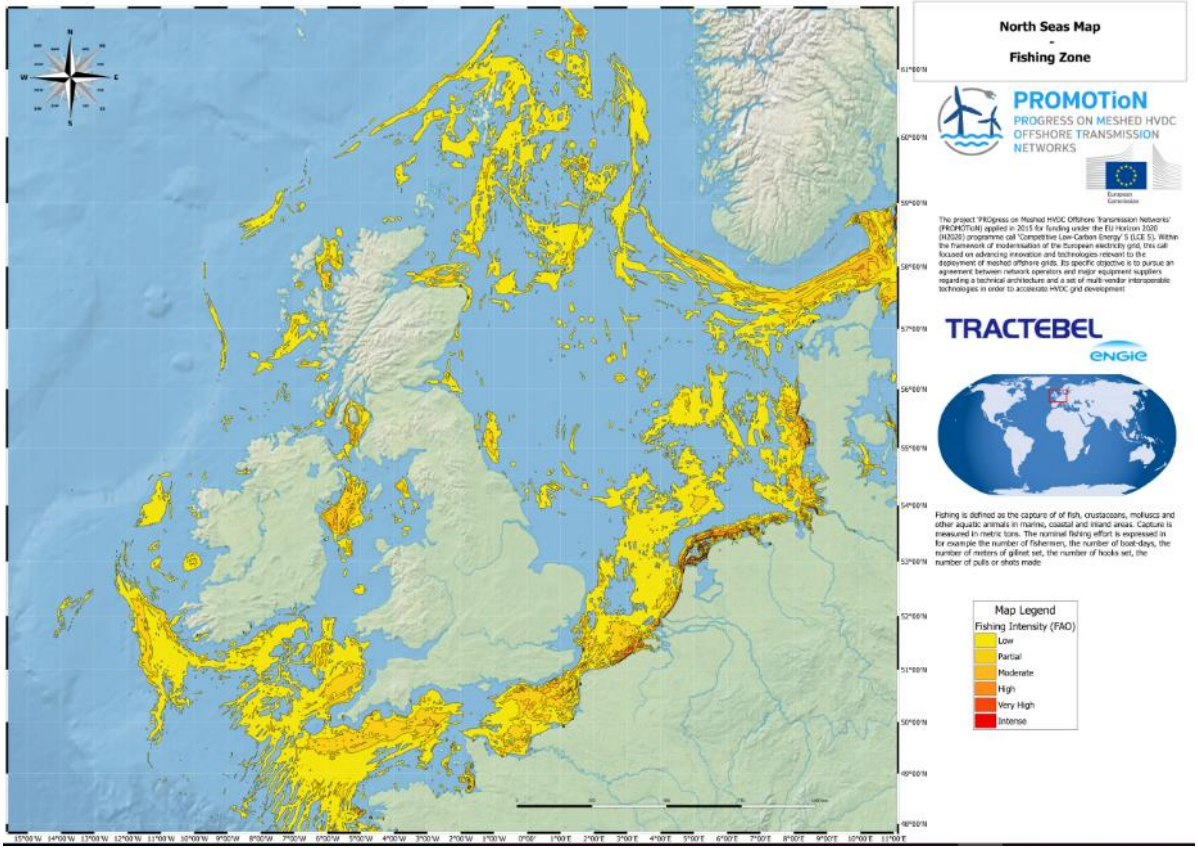


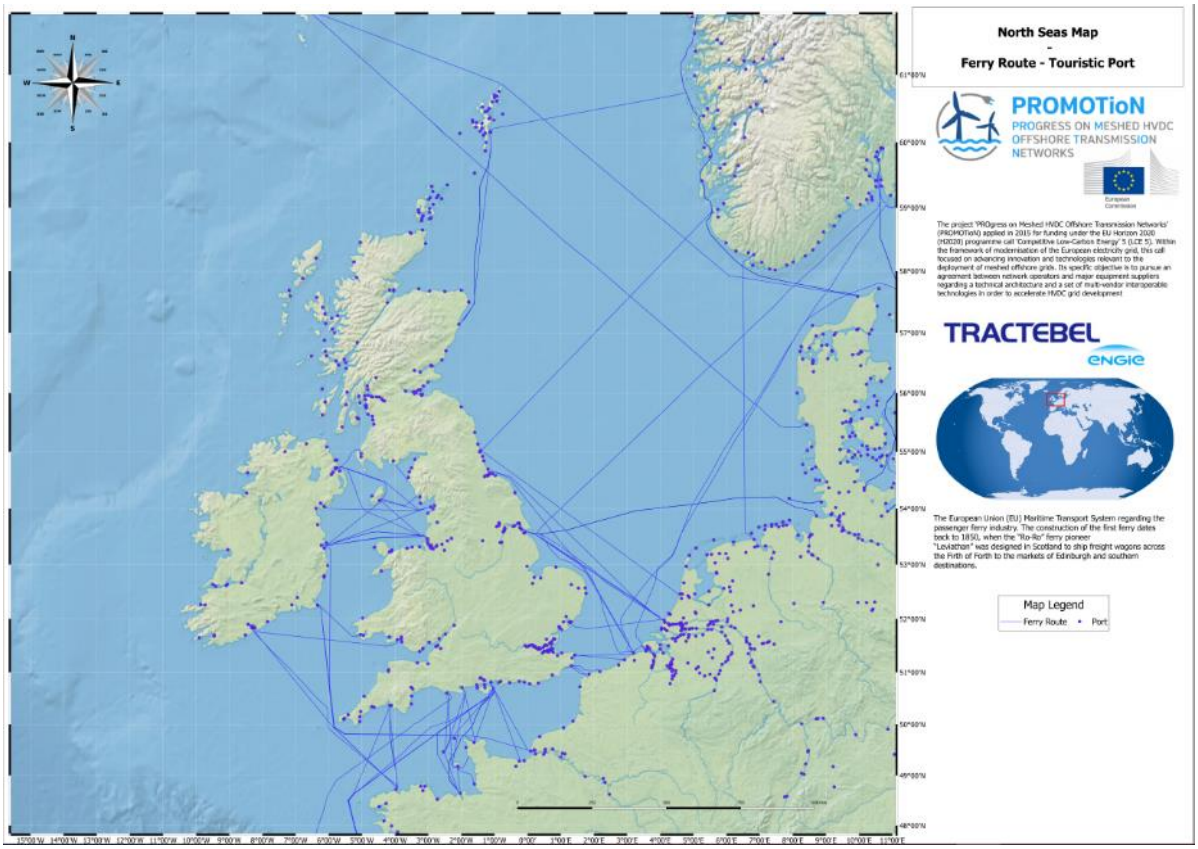

North Seas Map
-
Shipping Lane & Maritime route
PROMOTioN
PROGRESS ON MESHED HVDC OFFSHORE TRANSMISSION NETWORKS
TRACTEBEL
ENGIE
A sea lane, sea road or shipping lane is a regularly used route for vessels on oceans and large lakes. In the Age of Sail they were not only determined by the distribution of land masses but also the prevailing winds, whose discovery was crucial for the success of long voyages. Sea lanes are very important for trade by sea.
the sea lane or shipping lane are describing the primary maritime routes between ports, used for trade, logistics and naval forces.
Map Legend
Port
Marine_Lane

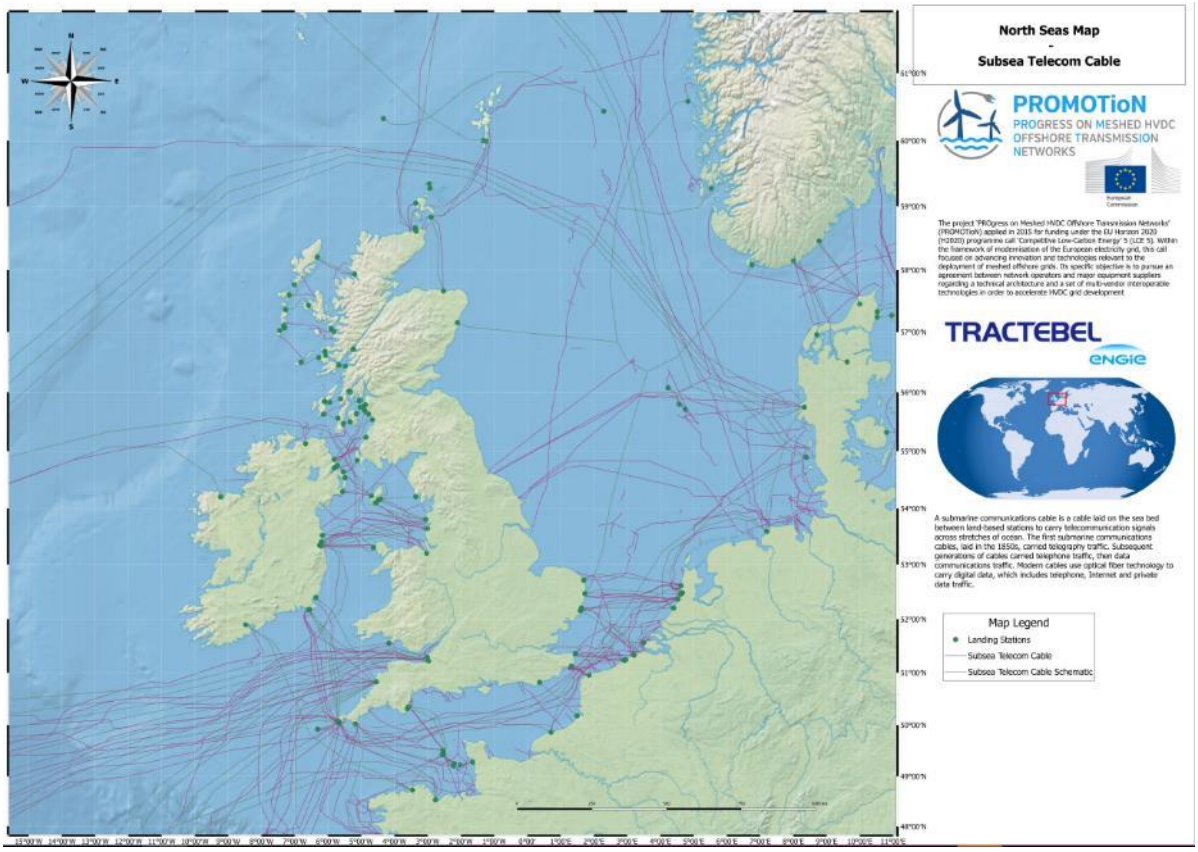

North Seas Map
-
Dredging and Spoils Dumping
PROMOTioN
PROGRESS ON MESHED HVDC OFFSHORE TRANSMISSION NETWORKS
TRACTEBEL
ENGIE
Sediment is an essential, integral and dynamic part of the ecosystem. Over 99% of sediment dumped at sea is locally-generated and results from dredging of harbours and their approaches to ensure they are navigable. Most dredged material is dumped at established sites. It is also used for purposes such as beach nourishment or land reclamation
Map Legend
Dredging Locations
Dredge Spoils dumping

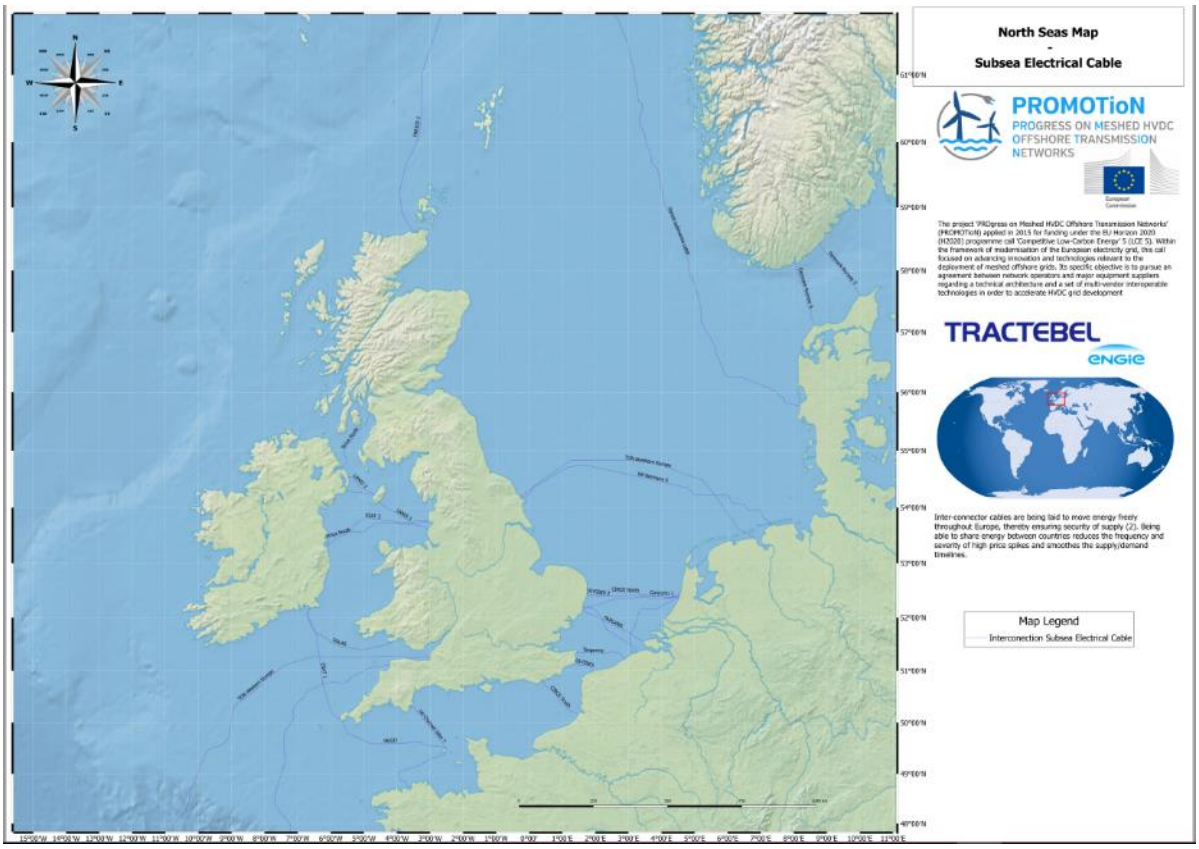

North Seas Map
-
Munition Dumping and Military restriction zones
PROMOTioN
PROGRESS ON MESHED HVDC OFFSHORE TRANSMISSION NETWORKS
The project 'PROgress on Meshed HVDC Offshore Transmission Networks' (PROMOTioN) applied in 2015 for funding under the EU Horizon 2020 (H2020) programme call 'Competitive Low-Carbon Energy' 5 (LCE 5). Within the framework of modernisation of the European electricity grid, this call focused on advancing innovation and technologies relevant to the deployment of meshed offshore grids. Its specific objective is to pursue an agreement between network operators and major equipment suppliers regarding a technical architecture and a set of multi-vendor interoperable technologies in order to accelerate HVDC grid development
TRACTEBEL
ENGIE
Data on munition dumping in European sea, An ammunition depot, ammunition supply point (ASP), ammunition handling area (AHA), ammunition dump, is a military storage facility for live ammunition and explosives.
The Navy uses the airspace, sea surface, sub-surface, and seafloor of the outer continental shelf for activities such as equipment testing and training exercises. The Air Force conducts flight training and systems testing over extensive areas offshore
Map Legend
Dumping Munition point
Dumping Munition area
military


North Seas Map
-
Oil and Gas Platform - Pipeline
PROMOTioN
PROGRESS ON MESHED HVDC OFFSHORE TRANSMISSION NETWORKS
The project 'PROgress on Meshed HVDC Offshore Transmission Networks' (PROMOTioN) applied in 2015 for funding under the EU Horizon 2020 (H2020) programme call 'Competitive Low-Carbon Energy' 5 (LCE 5). Within the framework of modernisation of the European electricity grid, this call focused on advancing innovation and technologies relevant to the deployment of meshed offshore grids. Its specific objective is to pursue an agreement between network operators and major equipment suppliers regarding a technical architecture and a set of multi-vendor interoperable technologies in order to accelerate HVDC grid development
TRACTEBEL
ENGIE
This list of oil and gas fields of the North Sea contains links to oil and natural gas reservoirs beneath the North Sea. In terms of the oil industry, "North Sea oil" often refers to a larger geographical set, including areas such as the Norwegian Sea and the UK "Atlantic Margin" (west of Shetland) which are not, strictly speaking, part of the North Sea.
Map Legend
Oil_Gaz_Platform
Closed down
Closed Down
Decommissioned
Decommissioned
Derogation
Operational
Removed
Other
Subsea Pipe Line


North Seas Map
-
Fishing Zone
PROMOTioN
PROGRESS ON MESHED HVDC OFFSHORE TRANSMISSION NETWORKS
TRACTEBEL
ENGIE
Fishing is defined as the capture of of fish, crustaceans, molluscs and other aquatic animals in marine, coastal and inland areas. Capture is measured in metric tons. The nominal fishing effort is expressed in for example the number of fishermen, the number of boat-days, the number of meters of gillnet set, the number of hooks set, the number of pulls or shots made
Map Legend
Fishing Intensity (FAO)
Low
Partial
Moderate
High
Very High
Intense


North Seas Map
-
Ferry Route - Touristic Port
PROMOTioN
PROGRESS ON MESHED HVDC OFFSHORE TRANSMISSION NETWORKS
TRACTEBEL
ENGIE
The European Union (EU) Maritime Transport System regarding the passenger ferry industry. The construction of the first ferry dates back to 1850, when the "Ro-Ro" ferry pioneer "Leviathan" was designed in Scotland to ship freight wagons across the Firth of Forth to the markets of Edinburgh and southern destinations.
Map Legend
Ferry Route
Port





SELECTION CRITERIA

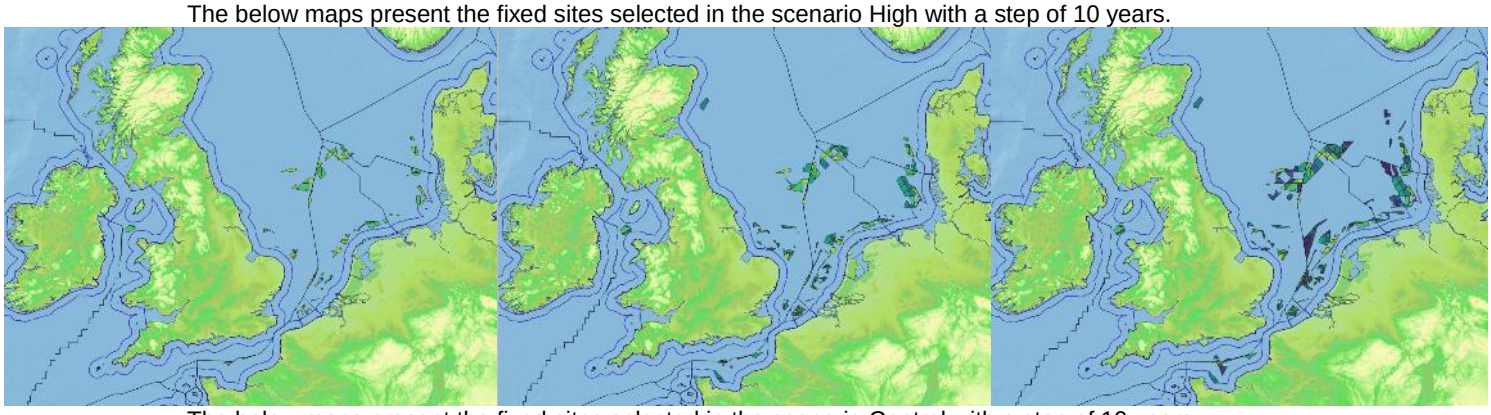
As a complement to Section 3.4.3, the table below summarises the selection criteria and their relative weight.

FACTOR	RELATIVE WEIGHING [%]	RANKING SCORE	
Wind Resource (m/s)	15	7,0 – 7,5 7,5 – 8,0 8,0 – 8,5 8,5 – 9,0 9,0 – 10 >10	0-2 2-4 4-6 6-8 8-9 10
Water depth (m)	50	**Fixed** 70 - 60 60 - 50 50 – 40 40 – 30 30 - - 0	 0-4 4-6 6-7 7-8 8-10
		Floating 400 – 300 300 – 200 200 – 150 150 – 100 100 – 50	 0-2 2-4 4-6 6-8 8-10
Distance from the Grid (km)	30	250 – 150 150 – 125 125 – 100 100 – 50 50 – 0	0 – 2 2 – 4 4 – 6 6 – 8 8 – 10
Distance from the Harbor (km)	5	250 – 150 150 – 125 125 – 100 100 – 50 50 – 0	0 – 2 2 – 4 4 – 6 6 – 8 8 – 10

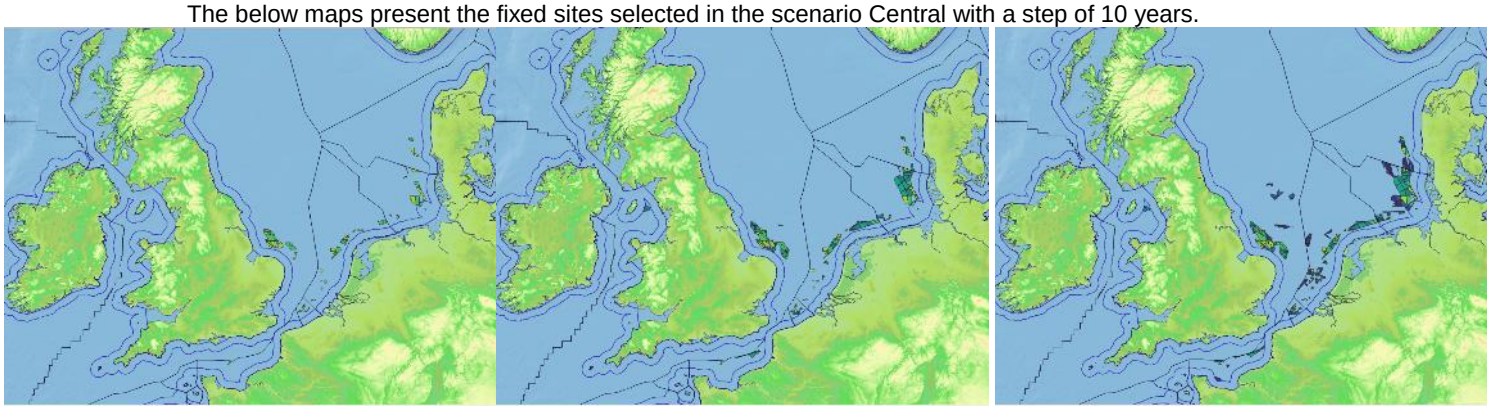
FINAL SELECTION OF PROJECTS PER SCENARIO

As a complement to Section 3.4.5, this Section presents the selected sites in 2030, in 2040 and in 2050 for each scenario. Sites with fixed and floating foundations are shown separately.

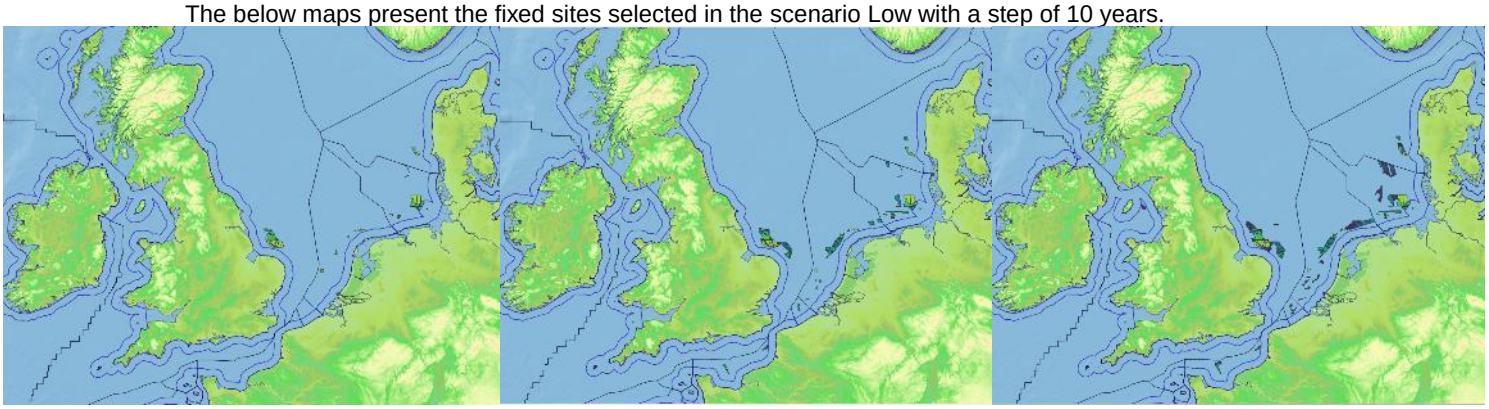
The below maps present the fixed sites selected in the scenario High with a step of 10 years.



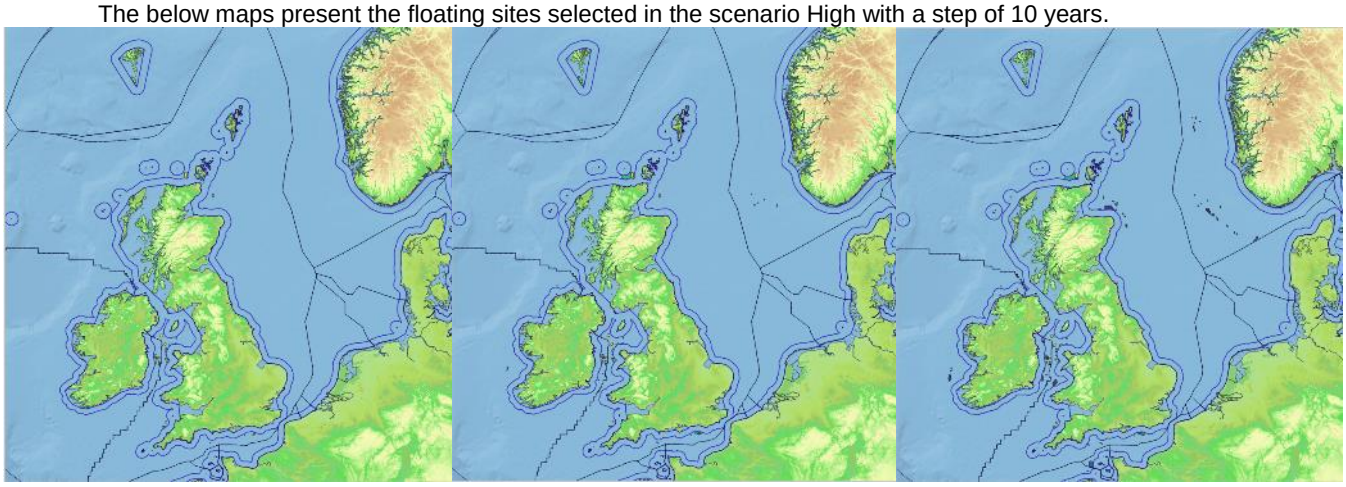
The below maps present the fixed sites selected in the scenario Central with a step of 10 years.



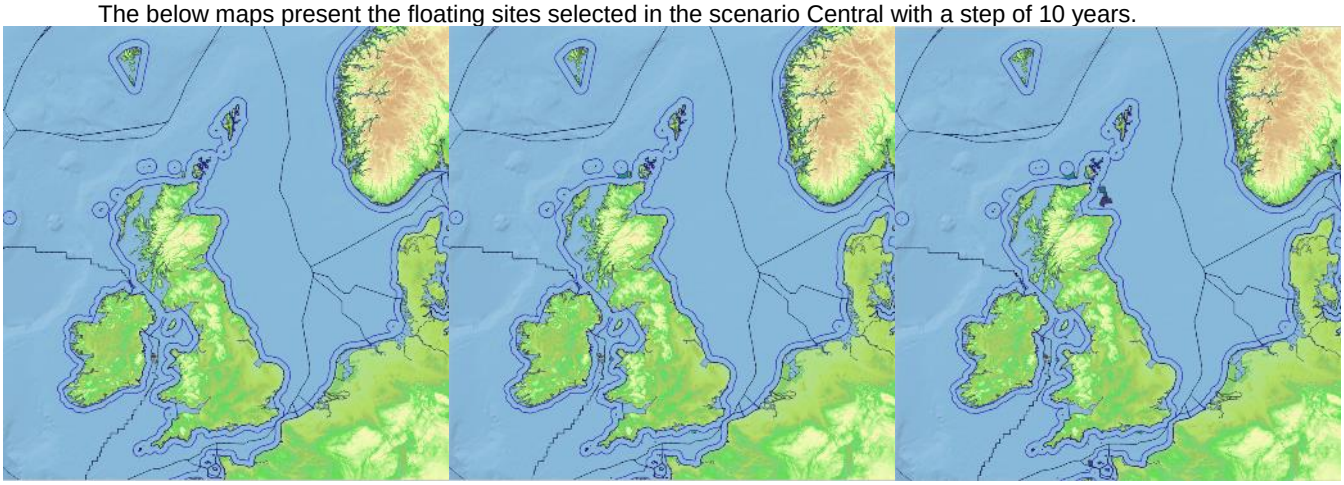
The below maps present the fixed sites selected in the scenario Low with a step of 10 years.



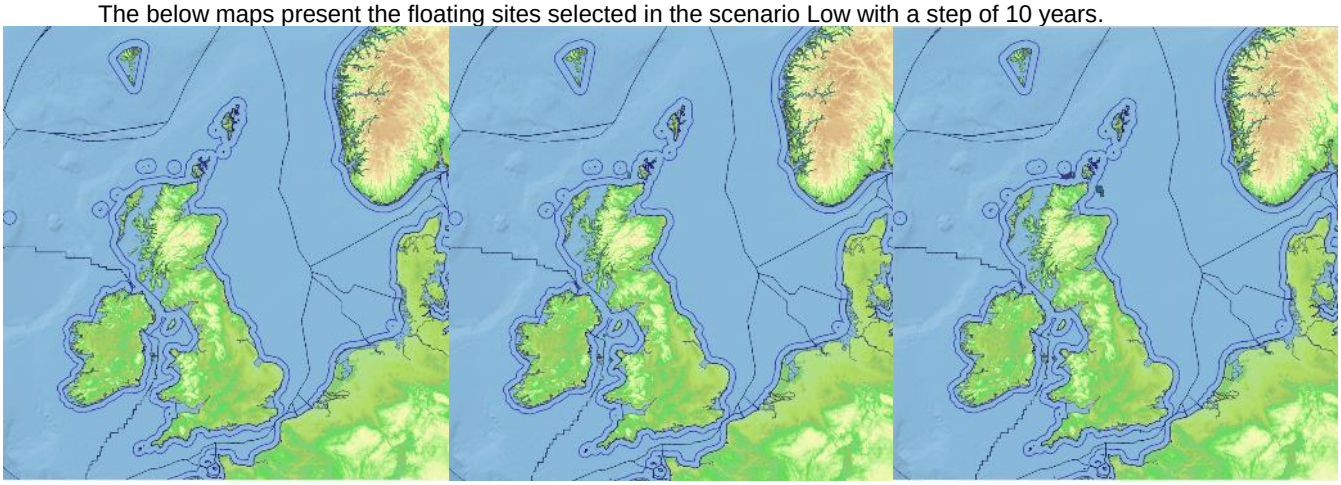
The below maps present the floating sites selected in the scenario High with a step of 10 years.



The below maps present the floating sites selected in the scenario Central with a step of 10 years.



The below maps present the floating sites selected in the scenario Low with a step of 10 years.



APPENDIX II

ASSUMPTIONS AND IMPLEMENTATION DETAILS

COSTS

The assumptions on costs per technologies are the scope of a separate Cost Data Collection document. The development of the topologies requires cost data on the following components:

- Cables cost per km for different voltage level and rating
- HVDC offshore substations including:
    - Offshore platform cost
    - Converter cost
    - Additional cost for landing an extra-cable

The analysis is performed in 5-year increments for both Step 1 and Step 2 (as described in Chapter 3). A foresight on 10 years is also included in Step 1. The topologies are developed by evaluating by time spans of 10 years, which topology for each concept leads to the least investment cost.

NUMBER OF ONSHORE NODES

The future development of the onshore grid has been the subject of many discussions. It is clear that the hosting capacity of onshore connection points and the potential bottlenecks that might be created by an increasing share of offshore wind needs to be analysed carefully when planning the onshore grid. In this report, a hosting capacity has been assumed at multiple potential onshore connection points. These connection points are typically located close to shore. The exact route of the DC lines onshore has not been analysed.

The current implementation identified a series of potential onshore connection points. It has been assumed that each of these points have a capacity of 4 GW. The impact of this assumption is that the wind is evacuated through multiple onshore points. This illustrates the needs to have coordinated onshore and offshore planning.

The number, location and hosting capacity of the onshore nodes do not vary from one concept to another.

NUMBER OF OFFSHORE NODES

An “offshore node” represents an aggregation of wind farms which can be connected to at least one potential HVDC offshore platform. The size of the offshore nodes is limited to 2 GW for the BAU and HUB concepts while the size constraint is not used for the NAT and EUR concepts.

It has to be noted that each offshore node belongs to one single country. In this study, it is not considered that offshore wind farms of different countries will be aggregated together.

NUMBER OF ARTIFICIAL ISLANDS

A maximum of six potential artificial islands are used in the development of the topologies for the centralised hub concept. The coordinates of the artificial islands are not optimised and are given as input to the algorithm. These coordinates represent feasible locations for building an energy island.

WHERE IS THE FRONTIER FROM AC TO DC?

It is currently accepted that HVDC starts to become more economic than AC transmission for subsea cables at a length of around 80 km.

Recent projects in Germany (e.g. Helwin) have shown that DC is used for offshore windfarms situated less than 50 km from shore. The reason is that the HVDC connection does not stop at the shore line but goes further onshore. The total distance makes therefore the HVDC technology more economic.

In the development of topologies, it is assumed that all offshore wind farms connected further than the 12 nautical miles limit, are likely to be connected to an HVDC platform. Also, all wind farms located less than 80 km apart can theoretically be connected in AC to an HVDC platform. The design of the offshore AC cables and platforms is not considered in this report.

Similarly, in the centralised hub concept, it can be assumed that wind farms close to the artificial island will be connected to the island using AC cable. This would considerably reduce the number of offshore platforms and the cost will be shifted from offshore platforms to the artificial island.

Choice of voltage level

CIGRE TB684 - Recommended voltages for HVDC grids

For the development of the topologies; some assumptions have been made on the voltage level of the offshore grid to simplify the analysis. In this study, the simulations have been performed using a single voltage level of 525kV for the whole North Sea region while a voltage level of 320kV has been assumed in the Channel and in the Irish Sea.

A single voltage level is used in the development of the topologies. This assumption is done for two reasons:

1. Most of the wind farms are still to be built, therefore it is feasible to set a single voltage level
2. The analysis aims at evaluating the added values of meshed versus non-meshed solutions. Having multiple voltage level can be mitigated by having back-to-back converters.

According to the CIGRE brochure, the voltage levels used for offshore HVDC converters are likely to be in the range 320-600kV.

The justification of the use of these voltage levels comes from the CIGRE TB684 and voltage level used for recent project. From past projects, it seems that voltage level of 320kV is predominantly used for projects up to 1 GW while higher voltage levels are used when the capacity is higher than 1.4 GW.

It is indeed possible that isolated point-to-point projects will use another voltage level but the goal of this report is to provide an overview of the global picture. It would be too ambitious and unrealistic to try to optimise the investment costs for each single potential project.

PLANNING CRITERIA

General assumptions:

- We do not want a hard N-1 constraint on offshore grids such that the offshore grid has to withstand the loss of any single element without offshore wind curtailment.
- However, as the offshore grid is part of the European power system, we want some form of N-1 security:
    - A single contingency in the offshore grid should not lead to major disturbances in the onshore grid (e.g. it should not lead to load shedding).

- The impact on the onshore grid should be limited to the maximum loss of power infeed.

To guarantee that the transmission capacity is installed in such a way as to meet that N-1 criterion, the maximum capacity of transmission circuits are as follows:

- 3 GW for Continental Europe: this is always met, since the maximum offshore circuit assumed in PROMOTioN is 2 GW;
- 1.4 GW for the Nordic system: slightly higher than their current 1.35 GW limit, but consistent with the North Sea Link and requires only a marginal adaptation of the primary reserve;
- Of maximum 1.8 GW for Great Britain to comply with the actual 1.85 GW limit: circuits of 2 GW cannot be used;
- Of maximum 700 MW for Ireland: higher than the current 500 MW, but consistent with the Celtic Interconnector and it also justifies the use of 320 kV.

ASSUMPTIONS ON LOAD PROFILES

The ENTSO-E Global Climate Action (GCA) load profiles of the North Seas countries are obtained by taking the average of the hourly GCA load values of the Wet (2007), Dry (1982) and Normal (1984) years of the ENTSO-E joint scenario data used in the TYNDP 2018. Using average values is relevant to assess the overall use of the HVDC offshore grid with best-estimate hourly load data.

Assessing the extreme conditions of use of this HVDC offshore grid would require using the Wet (2007) and Dry (1982) years load profiles as basis for load extrapolation. This has not been performed in this study.

The transmission expansion plan analysed in this study focuses on the GCA scenario. Load data are provided by ENTSO-E up to 2040 and for each country in this scenario. For the other years of analysis, refer to Chapter 5.

APPENDIX III

TOPOLOGY GENERATION RESULTS FOR THE CENTRAL WIND SCENARIO

The results will be presented successively for each of the four concepts for the Central wind scenario. This scenario assumes a total offshore installed capacity of around 150 GW in 2050 (which is 25% less than in the High wind scenario). In the Central wind scenario, there is no need to go as far offshore as for the High wind scenario. Therefore, the Dogger Bank is not exploited in this scenario.

For each concept, the results of the whole optimisation process are first shown for each optimisation time step (i.e. 5-year interval). This illustrates the potential development of the offshore grid from 2025 to 2050 for the Central wind scenario. Then, the observations of step 1 (OTEP) are described followed by the results of the optimisation of the interconnection. Next, there is a short section on recommendations drawn from the security analysis. The final section of this Appendix compares the different concepts..

BUSINESS-AS-USUAL APPROACH

EVOLUTION OF THE TOPOLOGY

For the sake of clarity, the results are first illustrated for both optimisation steps. This represents a potential future topology in the North Sea for the BAU concept and the Central wind scenario. The topologies are represented in Figure 2 to Figure 4. Note that these figures represent also existing/planned interconnectors as well as existing/planned windfarms.

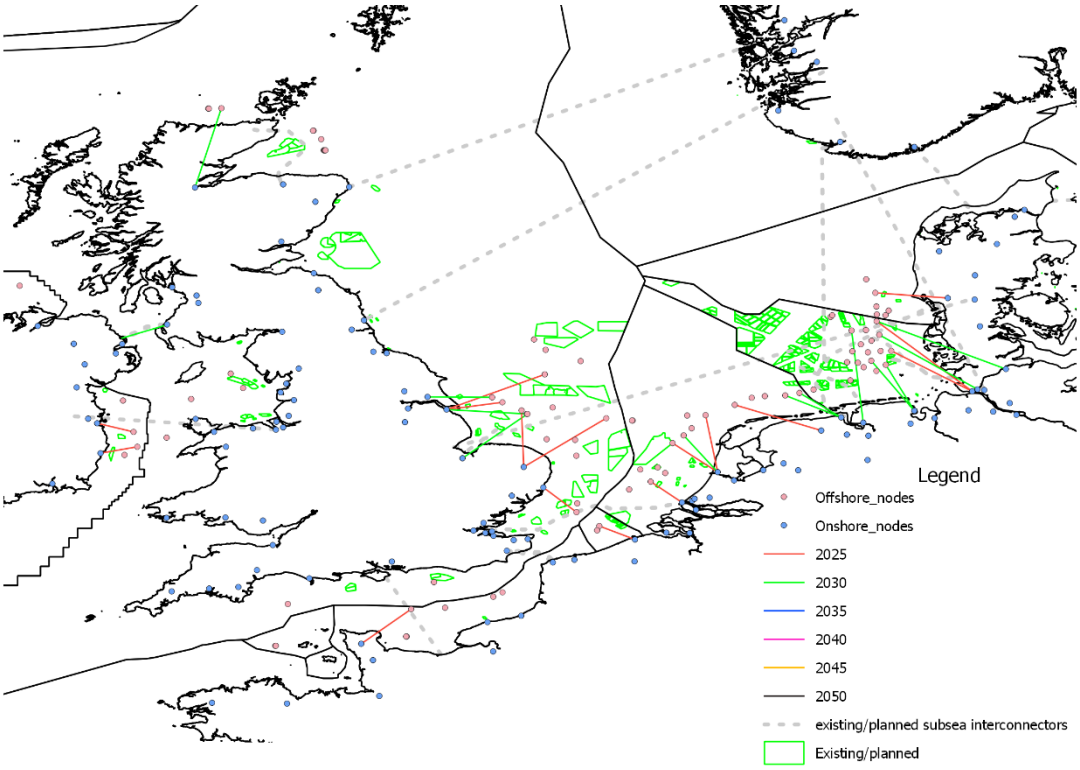


Figure 2 - Central wind scenario, BAU concept, topology in 2030.

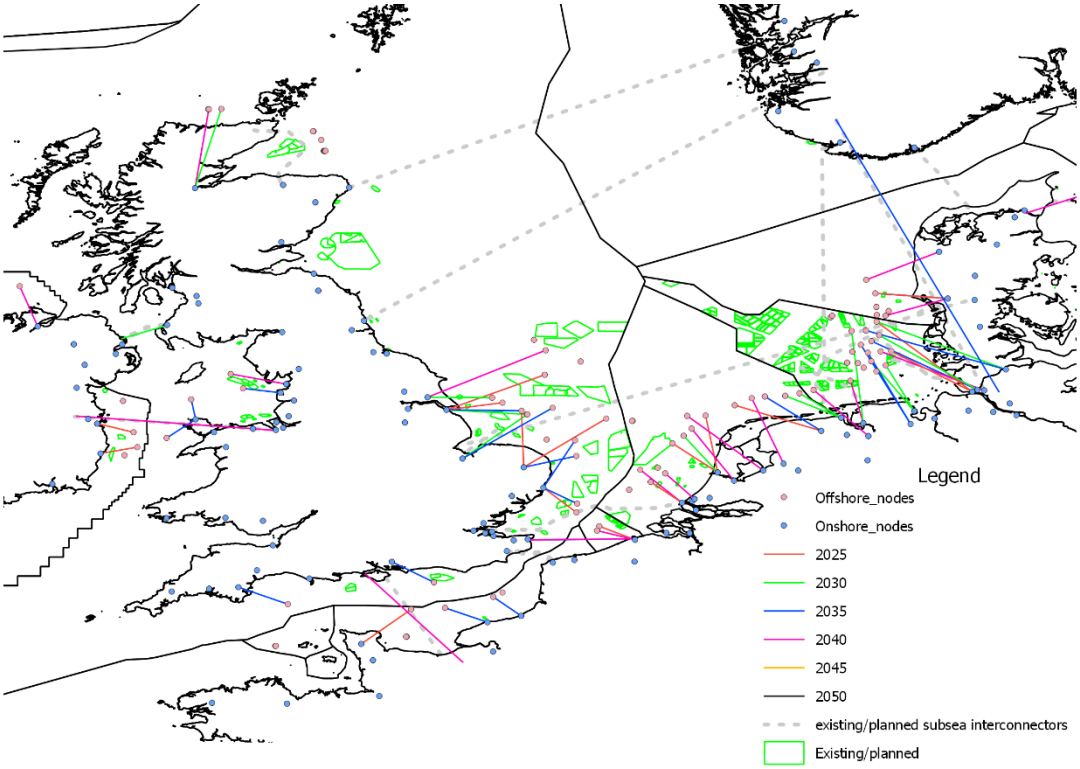


Figure 3 - Central wind scenario, BAU concept, topology in 2040.

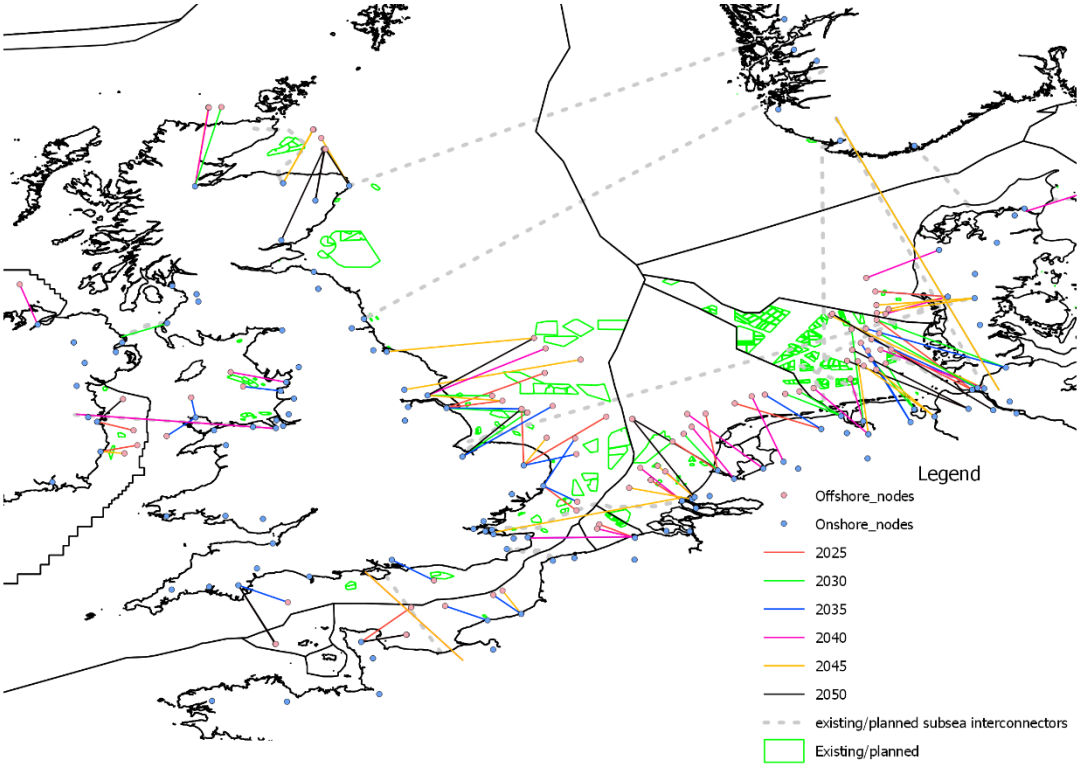


Figure 4 - Central wind scenario, BAU concept, topology in 2050.

STEP 1 - OTEP

The main observations resulting from the OTEP step for the BAU concept Central wind scenario are the following:

Onshore connections

In the BAU case, the OTEP step tends to connect the offshore nodes to the closest onshore points. Because of onshore hosting capacity constraint (maximum 4 GW per onshore connection), many onshore candidates are needed.

Anticipatory investment (temporary oversizing of cables)

The cable capacities are optimised for a 10-year horizon. Therefore, some cables are oversized for some target years in order to accommodate future offshore wind production.

STEP 2 - OPTIMISATION OF INTERCONNECTIONS

In the BAU approach, the candidate interconnectors are only from shore to shore. The results of the optimisation of the interconnections using the market model are shown in Table 2.

Table 2 - Transmission capacity expansions for BAU concept (GW) Central wind scenario. Numbers in black are the existing/planned interconnections, numbers in red are the point-to-point expansions.

INTERFACE	2020	2025	2030	2035	2040	2045	2050
BE-GB	1	1	1	1+1.8	1+3	1+3	1+3
DE-DKe	1	1	1	1	1+0.5	1+0.5	1+0.5
DE-GB	1.4	1.4	1.4	1.4	1.4	1.4	1.4
DE-NOs	1.4	1.4	1.4+2	1.4+2.2	1.4+2.6	1.4+5.4	1.4+5.6
DKw-GB	0	1.4	1.4	1.4	1.4	1.4	1.4
DKw-NL	0.7	0.7	0.7	0.7	0.7	0.7	0.7
DKw-NOs	1.6	1.6	1.6	1.6	1.6	1.6	1.6
FR-GB	4	6.8	6.8	6.8	6.8+1.6	6.8+3.9	6.8+3.9
GB-IE	0.5	0.5	0.5	0.5	0.5+0.5	0.5+1.2	0.5+1.2
GB-NI	0.5	0.5	0.5+0.9	0.5+0.9	0.5+0.9	0.5+0.9	0.5+0.9
GB-NL	1	1	1	1	1	1+1.4	1+1.6
GB-NO	0	2.8	2.8	2.8	2.8	2.8	2.8

The following observations are made on the BAU model. These observations result from an optimisation trying to reduce the overall operation costs by investing in the least-cost candidate transmission lines. In the BAU model, the candidates for transmission expansion are direct connections from one country to another. In this concept it is not permitted to create an interconnection from extending an offshore transmission line.

BELGIUM-GREAT BRITAIN AXIS

The interconnection from Belgium to Great Britain is expanded by 3 GW in 2040 which results in a total of 4 GW of interconnection. It is worth remembering that the Central wind scenario assumes a higher solar and onshore wind penetration than the High wind scenario. Therefore, this illustrates that the need for interconnection is present for all the studied scenarios.

GERMANY-NORWAY AXIS

Germany goes through a period of high short-run marginal cost (SRMC) due to the phase-out of nuclear and of coal from 2030 to 2035. An alternative is to source energy from Norway, which has plenty of flexible hydro generation and an economic candidate for transmission expansion from Germany to the southern part of Norway. The optimised transmission investment is around 3 GW connecting Germany to Norway in 2040 and almost 6 GW in 2050. This value is higher than in the High wind scenario. One explanation can be that in our assumptions on the climate year (i.e. solar, hydro and wind profiles) capture complementarity between solar production and hydro storage capacities.

GERMANY-EASTERN DENMARK AXIS

The investment in a transmission line from Germany to Eastern Denmark is seen as a good option to increase the existing interconnection by 500 MW. This investment is justified thanks to the reduction the overall operation costs that it triggers.

FRANCE-GREAT BRITAIN AXIS

Exports of electricity from France to Great Britain rely in the BAU model on the country-to-country interconnection. As this line is congested about half the year from 2035 to 2050, an investment in the candidate transmission line between these two countries is justified to minimise their difference of SRMC costs. The transfer capacity built amounts to 1.6 GW in 2040 and almost 4 GW in 2050.

GREAT BRITAIN-NORTHERN IRELAND AND GREAT BRITAIN-IRELAND AXES

The interconnection candidates between Great Britain on one side, Ireland and Northern Ireland on the other side trigger an investment in these two interconnections. A 900 MW investment is performed in 2035 between Great Britain and Northern Ireland. Between Great Britain and Ireland, the investment amounts to 1200 MW in 2045.

GREAT BRITAIN-THE NETHERLANDS AXES

The interconnection from Great Britain to The Netherlands is also reinforced but, in contradiction to the Belgium to Great Britain interconnections, the capacity is lower than in the High wind scenario.

CONGESTIONS ON THE COUNTRY-TO-COUNTRY INTERCONNECTIONS OF THE TYNDP

Several interconnectors in the TYNDP model congest during a significant proportion of the years from 2020 to 2050. Notably, the interconnections from Denmark-East to Denmark-West, from Denmark-West to Sweden, from France to Belgium, France to Germany, Belgium to Great Britain, Belgium to Germany, and, from 2035, from the Netherlands to Germany are highly used. Major hydropower exports also congest the transmission lines from Norway to the Southern region of Norway (where the load is located) and to Sweden. The absence of candidate lines prevents further operational cost reductions in this region.

STEP 3 - SECURITY ANALYSIS

In the BAU case, the N-1 security analysis leads to loss of power infeed. By design, there are no cases where the consequence of fault spreads to the rest of the MOG.

NATIONAL DISTRIBUTED HUBS APPROACH

EVOLUTION OF THE TOPOLOGY

In this Section, the results are illustrated for both optimisation steps. This represents a potential future topology in the North Sea for the NAT concept and the Central wind scenario. The topologies are represented from Figure 5 to Figure 7. Note that these figures represent existing/planned interconnectors as well as existing/planned windfarms. It can be observed that the network is composed of radial and multi-terminal connections. The meshing component is less clear than in the High wind scenario, but there are some multi-terminal structures connecting multiple wind farms and multiple countries.

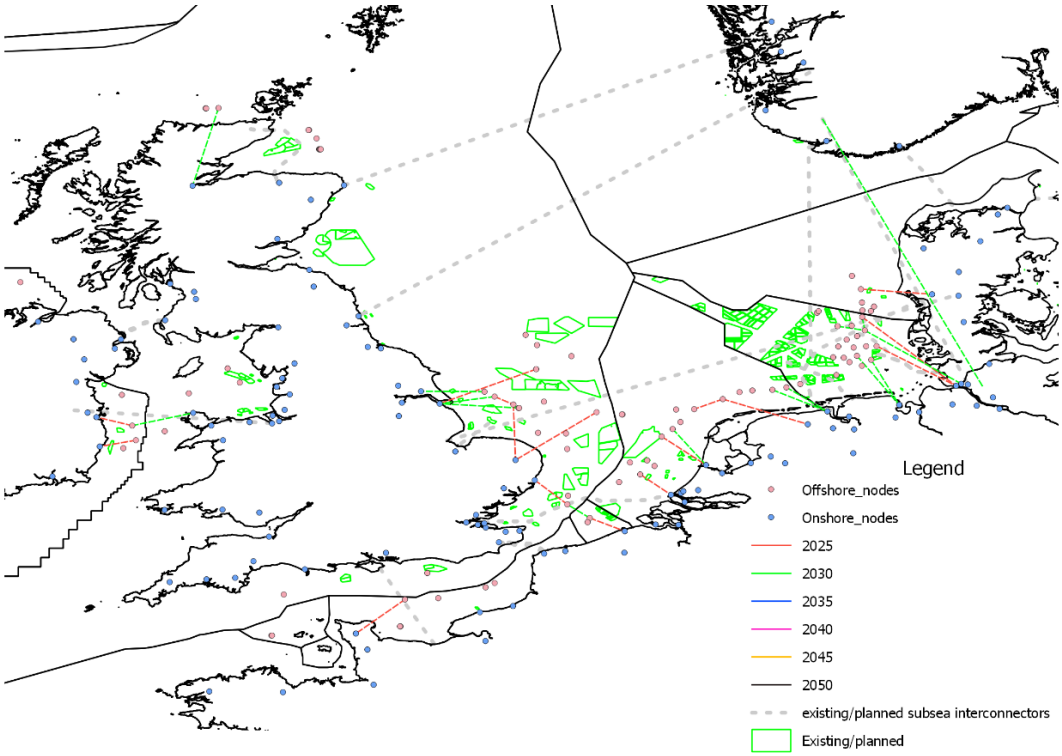


Figure 5 - Central wind scenario, NAT concept, topology in 2030.

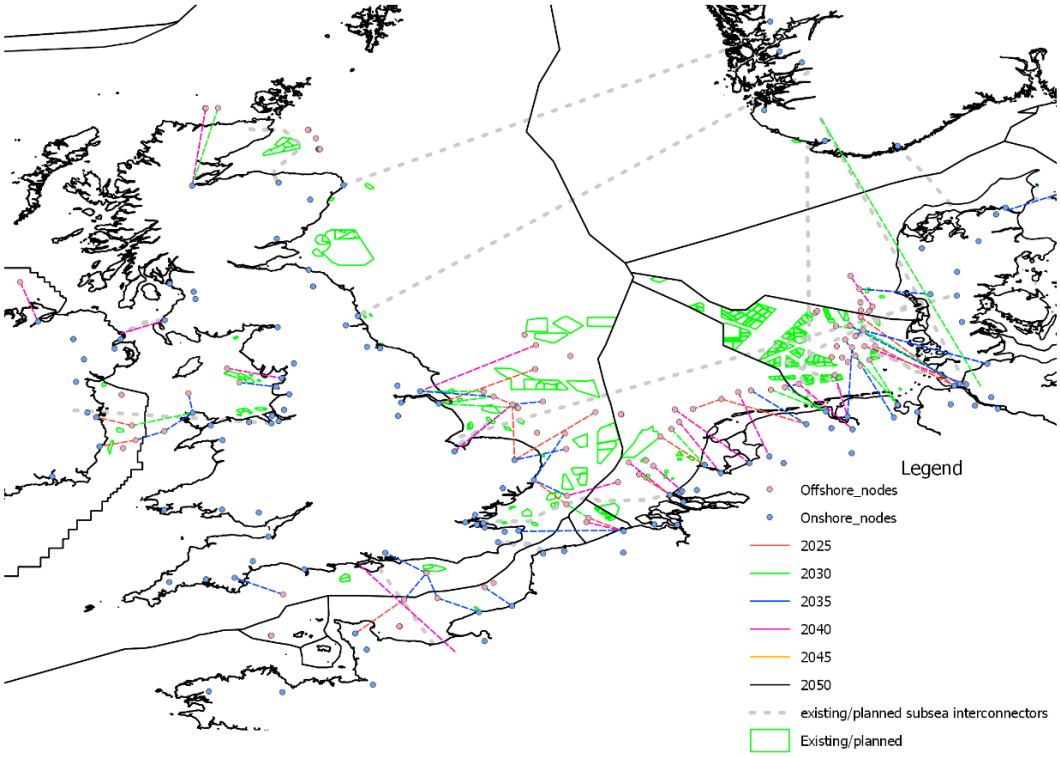


Figure 6 - Central wind scenario, NAT concept, topology in 2040.

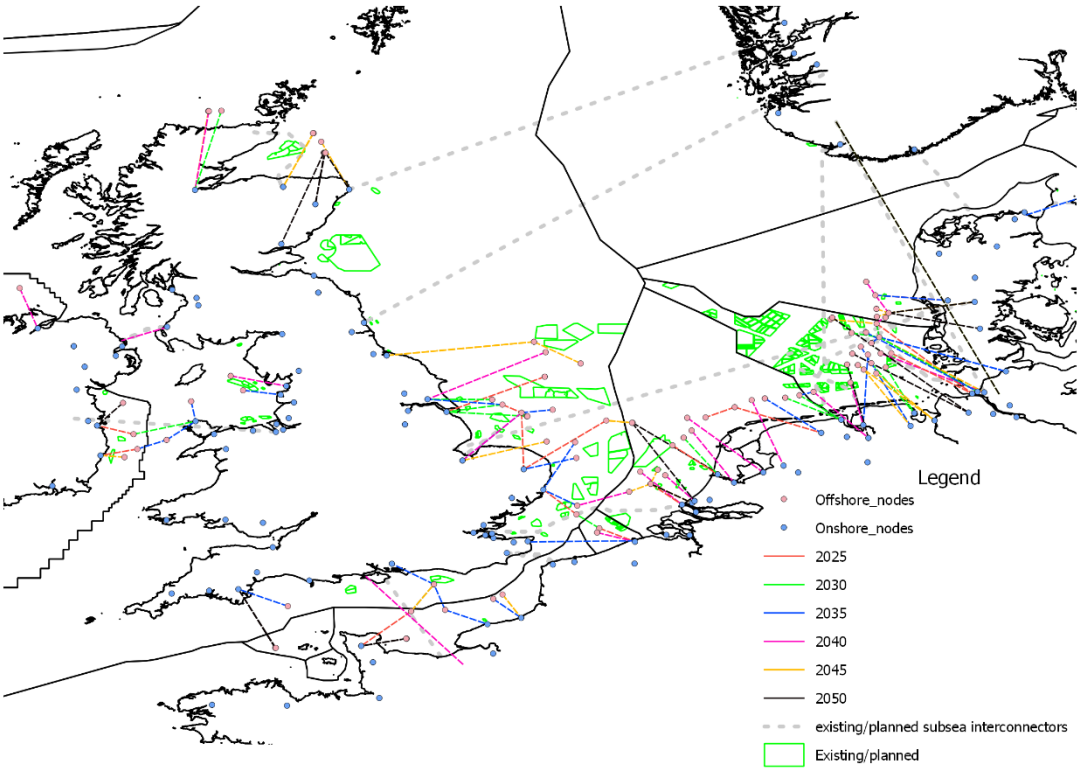


Figure 7 - Central wind scenario, NAT concept, topology in 2050.

STEP 1 - OTEP

The results of the OTEP can be observed from the previous figures. In the NAT concept, it is not allowed in step 1 to interconnect nodes from different countries. Therefore; all connections within the same country come from step 1 while the cross-border connections (onshore and offshore) come from step 2. As a reminder, this step is

performed to find the least cost topology able to evacuate the offshore wind energy to shore. The main observations of this step for the NAT case are:

Creation of multi-terminal DC connections

In the NAT case, the OTEP step tends to create a multi-terminal DC grid in order to optimise the use of cable rating and therefore to minimise the cable length. The multi-terminal DC grids can be found at some specific locations and are influenced by the locations of the wind farms and by their expected expansion. Therefore, a coordination planning of the transmission investments and OWF development is required.

Anticipatory investments and modularity

Similar to the BAU concept, the NAT concept requires anticipatory investments. Therefore, cables might be oversized for some target years or the multi-terminal connections may be created in order to facilitate future wind generation. The multi-terminal connections might also create more connection options for future wind farms which bring modularity in the development of the MOG.

Onshore connections

Because of onshore hosting capacity constraint (maximum 4 GW per onshore connection), many onshore candidates are needed. However, the difference with the BAU concept is that in some cases, a multi-terminal connection is used to reach an onshore point with sufficient hosting capacity.

STEP 2 - OPTIMISATION OF INTERCONNECTIONS

Table 3 lists the investments in transmission capacity expansion on the candidate interconnectors. The candidates without investment are removed from the table. Point-to-point interconnection capacity investments are allowed from 2030 on; the offshore interconnection investments are allowed from 2025 on.

Table 3 - Transmission capacity expansion in the NAT concept Central wind scenario (in GW). Numbers in black are the existing/planned interconnections, numbers in red are the point-to-point expansions and in blue the expansions via the MOG.

INTERFACE	2020	2025	2030	2035	2040	2045	2050
BE-GB	1	1	1+1.2	1+1.1+1.2	1+1.1+1.2	1+1.1+1.2	1+1.1+1.2
DE-DKe	1	1	1	1	1	1+0.5	1+0.5
DE-DKw					0.7	1.9	1.9
DE-GB	1.4	1.4	1.4	1.4	1.4	1.4	1.4
DE-NL				0.6	1.2	1.2	1.2
DE-NOs	1.4	1.4	1.4+2	1.4+2	1.4+2	1.4+4	1.4+4.7
DKw-GB	0	1.4	1.4	1.4	1.4	1.4	1.4
DKw-NL	0.7	0.7	0.7	0.7	0.7	0.7	0.7
DKw-NOs	1.6	1.6	1.6	1.6	1.6	1.6	1.6

FR-GB	4	6.8	6.8+0.5	6.8+0.5	6.8+1.4+0.7	6.8+1.4+1.9	6.8+1.4+1.9
GB-IE	0.5	0.5	0.5+1.8	0.5+1.8	0.5+2.2	0.5+2.2	0.5+2.2
GB-NI	0.5	0.5	0.5	0.5	0.5	0.5+0.7	0.5+0.7
GB-NL	1	1	1	1	1+1.6	1+3.6	1+0.4+3.6
GB-NO	0	2.8	2.8	2.8	2.8	2.8	2.8

GERMANY-NORWAY AXIS

For the Central wind scenario, there is no investment via the MOG to increase the transfer capacity between Germany and Norway. However, the investment on the direct interconnection is significant and amounts to almost 5 GW additional in 2050. See Figure 8. Additional investment in offshore lines are in cyan, and MOG topology derived from step 1 is shown in green.

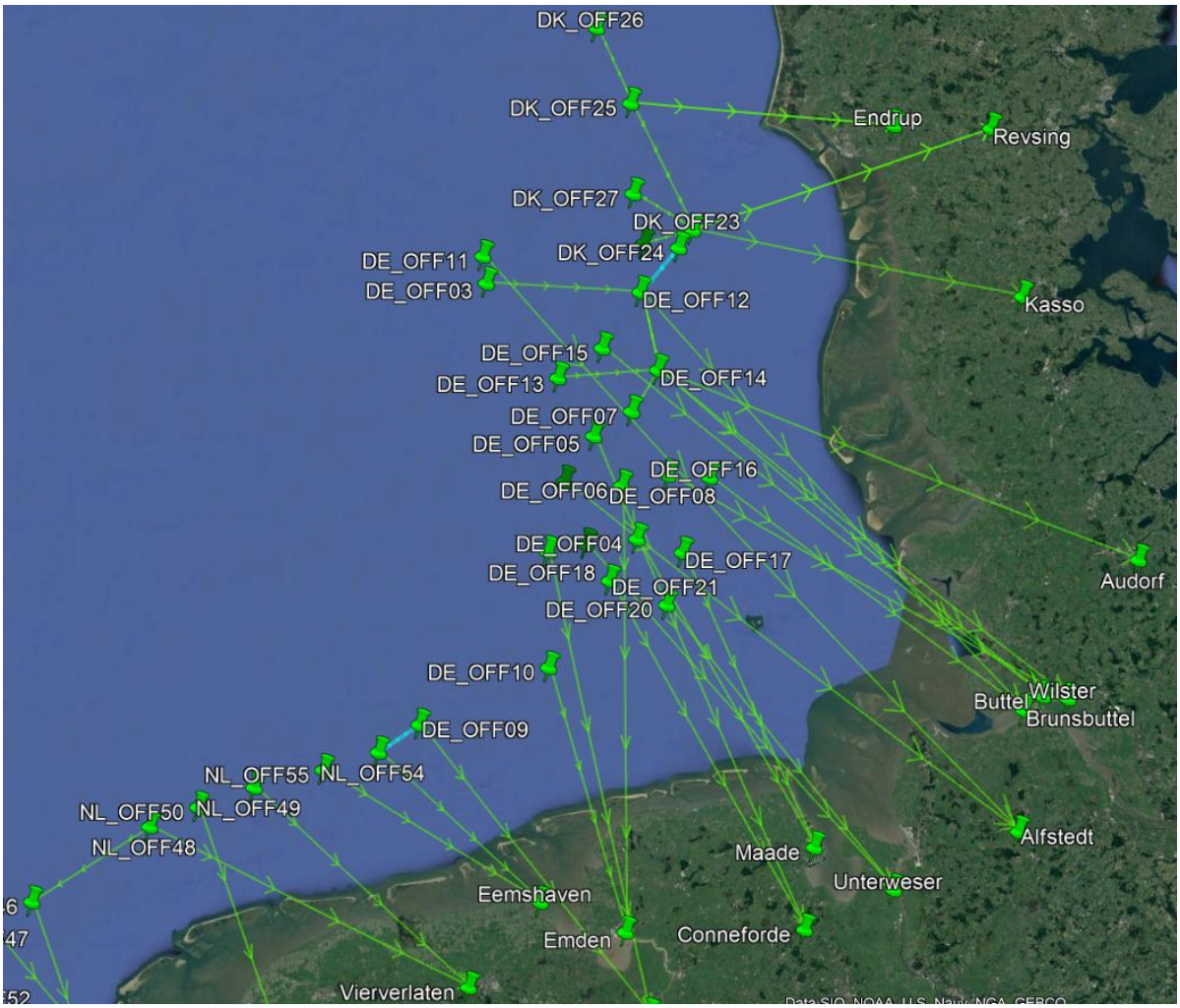


Figure 8 - The offshore reinforcements (blue) to increase the Dutch-German and the German-Danish transfer capacity.

GERMANY-EASTERN DENMARK AXIS

The country-to-country candidate transmission line is extended in 2040 by 0.5 GW in the NAT case which is similar to the BAU case.

GERMANY-WESTERN DENMARK AXIS

The proximity of the Dutch and Danish offshore wind farms make them ideal candidates to increase the interconnection capacities between these two countries. This results in 2 GW additional interconnection capacity via the MOG in 2050.

FRANCE-GREAT BRITAIN AXIS

In the NAT model, the investment in the direct country-to-country interconnection from France to the UK is reduced compared to BAU by investment in the offshore interconnection UK_OFF89-FR_OFF31 and/or UK_OFF89-FR_OFF33.

The total transmission capacity developed between France and Great Britain in the NAT model is almost identical to the one of the BAU model, but using also multi-terminal connections. Refer to Figure 9.

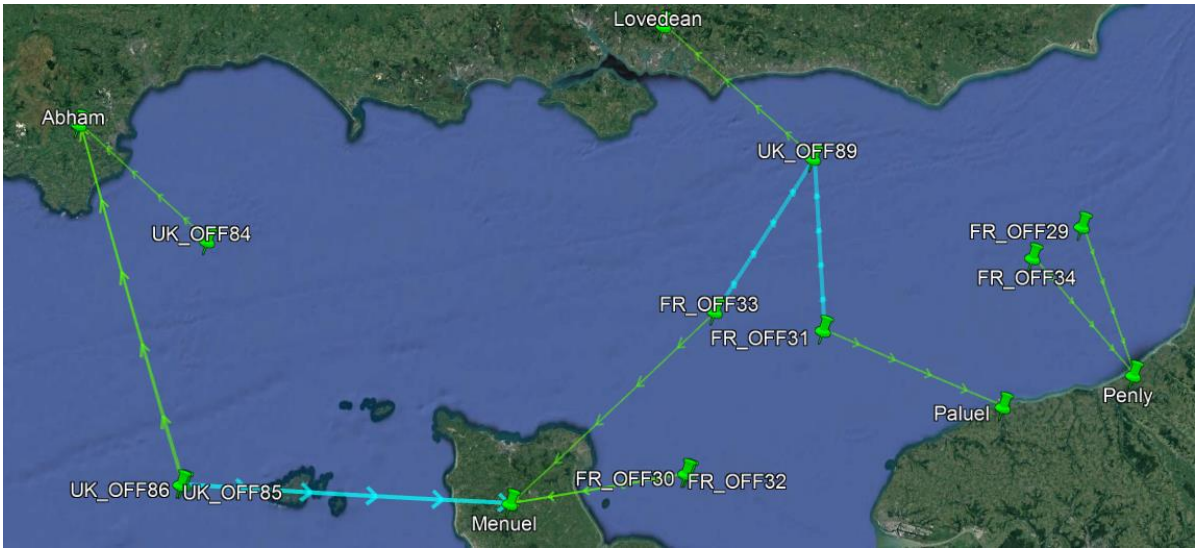


Figure 9 - France-Great Britain interconnection via MOG in The Channel.

GREAT BRITAIN-NORTHERN IRELAND AND GREAT BRITAIN-IRELAND AXES

The offshore candidate transmission line IR_OFF35-UK_OFF59 is developed. See Figure 10.

Figure 10 - Great Britain-Ireland interconnection via MOG.

GREAT BRITAIN - THE NETHERLANDS AXIS

The development of this axis can be significantly improved by using the MOG. The transfer capacity is more than doubled compared to the BAU concept by using shorter cables. Refer to Figure 11.

Figure 11 - Belgium, Netherlands and Great Britain interconnections can be reinforced via the MOG.

CONGESTIONS ON THE COUNTRY-TO-COUNTRY INTERCONNECTIONS OF THE TYNDP

The congestions of the onshore connections of the BAU model are alleviated by the expansion between Germany and The Netherlands and between Germany and West Denmark.

STEP 3 - SECURITY ANALYSIS

In the NAT case, load flow analyses in the healthy state (no outage) were performed for each target year at maximum wind production. No overload or overvoltage of equipment was observed.

In N-1, droop control is required to avoid over-voltages post-contingency. Special protection schemes might also be needed to initiate fast control actions post-contingency to avoid overloads.

EUROPEAN CENTRALISED HUBS APPROACH

EVOLUTION OF THE TOPOLOGY

In this section, the results are illustrated for both optimisation steps. This represents a potential future topology in the North Sea for the HUB concept and the Central wind scenario. Four artificial islands have been located in the North Sea and are assumed available from 2025. The topologies are represented from Figure 12 to Figure 14. Note that these figures represent also existing/planned interconnectors as well as existing/planned windfarms. It can be observed that the wind farms close to each hub tend to connect first to the hub and then the hub is connected to shore or to another hub. It can also be observed some hubs seem to be more ideally located than others. This emphasises that the number and locations of hubs play a key role and would need to be further investigated if the HUB concept is followed for developing the offshore grid. In terms of interconnections, most of the hubs are connected to each other, meaning that there is an economic benefit to build these interconnections if the hubs are built and available.

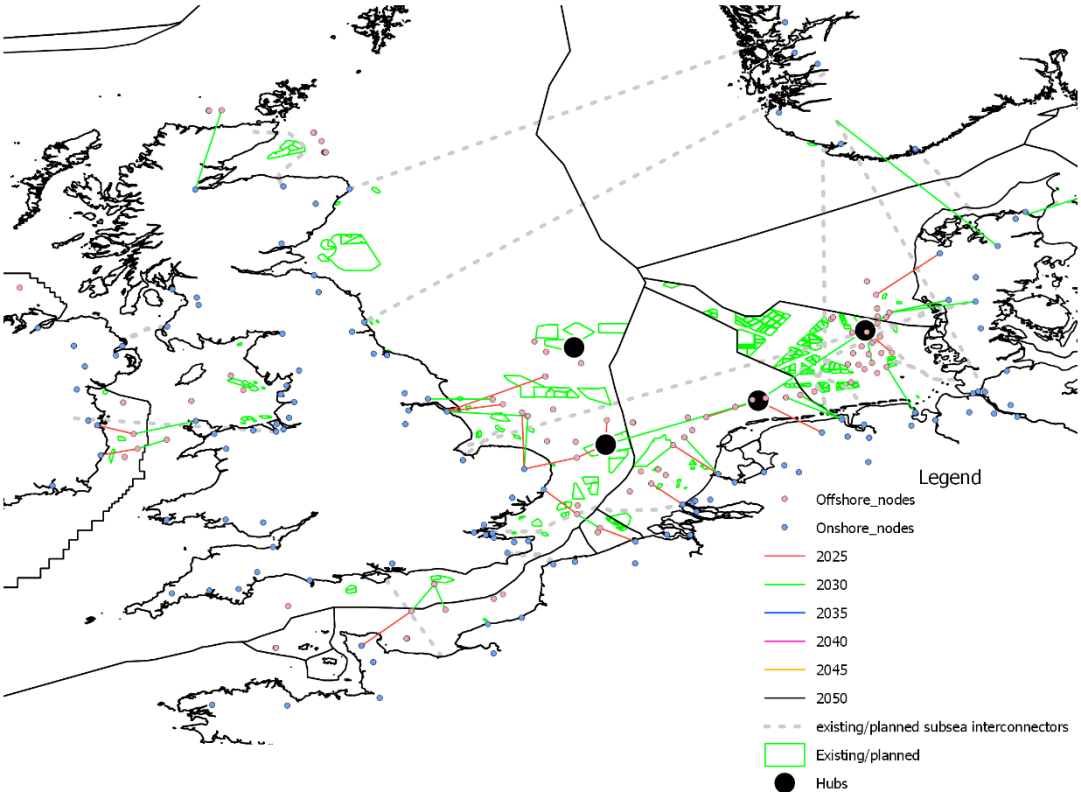


Figure 12 - Central wind scenario, HUB concept, topology in 2030.

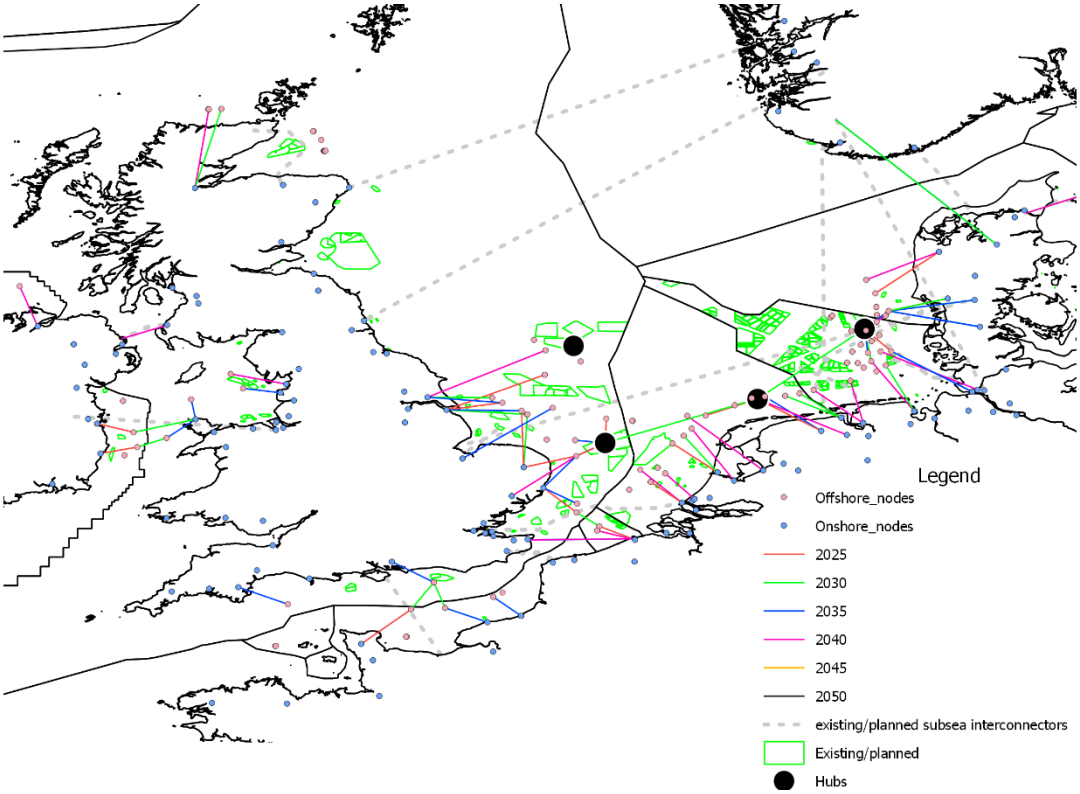


Figure 13 - Central wind scenario, HUB concept, topology in 2040.

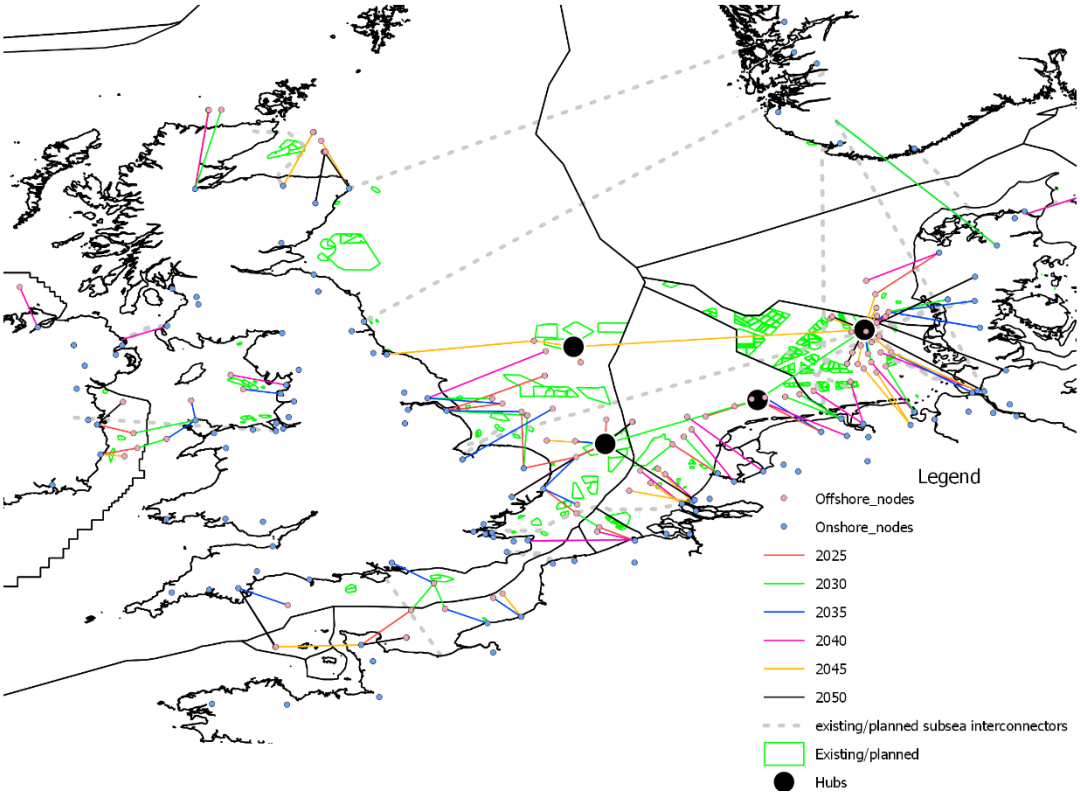


Figure 14 - Central wind scenario, HUB concept, topology in 2050.

STEP 1 - OTEP

The main observations resulting from the OTEP step for the Central wind scenario and HUB concept are the following:

AC-connection to hub

In the centralised-hub concept, four artificial islands are considered. The connections from an offshore node to the artificial islands can be much cheaper if the distance allows an AC connection. The cables from islands to islands and from islands to shore are only in DC. Therefore, the algorithm tends to connect wind farms to the closest island and then to optimise the number of DC cables from each island to shore. However, this depends on the distances between the wind farms and the island, and between the wind farm and the shore. The islands between The Netherlands and Great Britain and between Germany and Denmark seem to be very beneficial for this concept. This illustrates that the planning of the hubs and of the offshore wind farms has to be coordinated.

DC connection to shore and between islands

The connections to shore and between islands are done only in DC. Because the wind production is aggregated to each island, most of the DC cables will have a high rating.

Multi-terminal DC connection

For windfarms located between shore and an island, it might be interesting to connect them using a multi-terminal DC connection between the island, the windfarm and the shore.

STEP 2 - OPTIMISATION OF INTERCONNECTIONS

Table 4 lists the investments in transmission capacity expansion on the candidate interconnectors. The table makes the distinction between already planned/existing interconnections, direct interconnections and interconnections via hubs.

Table 4 - Transmission capacity expansion in the HUB concept Central wind scenario (in GW). Numbers in black are the existing/planned interconnections, numbers in red are the point-to-point expansions and in blue the expansions via the MOG.

INTERFACE	2020	2025	2030	2035	2040	2045	2050
BE-GB	1	1	1+1.3	1+1+1.3	1+2.4+1.3	1+2.4+1.3	1+2.4+1.3
DE-DKe	1+0.2	1+0.2	1+0.2	1+0.2	1+0.2	1+0.2	1+0.2
DE-GB	1.4	1.4	1.4	1.4	1.4	1.4	1.4
DE_hub-GB_hub	0	0	0	0	0.9	1.6	1.6
DE_hub-NL_hub	0	0	0.6	0.6	0.6	0.6	0.6
DE-NOs	1.4	1.4	1.4	1.4	1.4	1.4	1.4
DK_hub-DE_hub	0	0	0	0	1.1	2.7	2.7
DKw-GB	0	1.4	1.4	1.4	1.4	1.4	1.4

INTERFACE	2020	2025	2030	2035	2040	2045	2050
DKw-NL	0.7	0.7	0.7	0.7	0.7	0.7	0.7
DKw-NOs	1.6	1.6	1.6+2	1.6+2	1.6+3	1.6+4	1.6+4
FR-GB	4	6.8	6.8	6.8+0.2+4	6.8+0.2+4	6.8+0.2+4	6.8+0.2+4
GB-IE	0.5	0.5	0.5+2	0.5+2	0.5+2	0.5+2	0.5+2
GB-NI	0.5	0.5	0.5	0.5+0.2	0.5+0.2	0.5+0.2	0.5+0.2
GB-NL	1	1	1	1	1	1	1
GB_hub-NL_hub	0	0	0.5	0.5	0.5	0.5	0.5
GB-NO	0	2.8	2.8	2.8	2.8	2.8	2.8

The HUB model leaves the possibility of investing between the HUBs located to interconnect the countries. The same expansion candidates than in the NAT concept are also considered between Great Britain and France, and in the Irish Sea. The cost-effective investments in the candidate transmission lines via the MOG are shown on Figure 15. Additional investment in offshore lines are in cyan, and MOG topology derived from step 1 is shown in green.

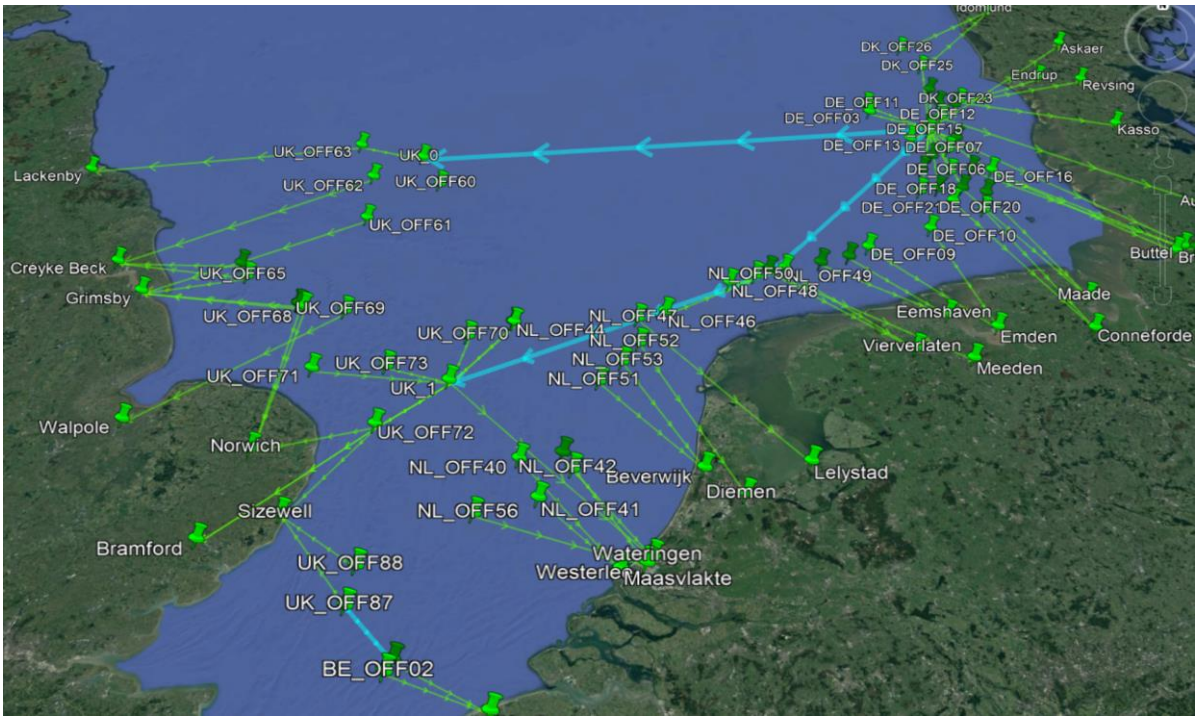


Figure 15 - Investments between hubs for the HUB concept.

GERMANY-NORWAY AXIS

The direct connection from Germany to Norway is not expanded in the HUB concept. This is due to the higher transfer capacity available from Germany to West Denmark via the hub. Then, it is preferred to invest on the direct connection West Denmark-Norway.

GERMANY-EASTERN DENMARK AXIS AND WEST DENMARK-SWEDEN AXIS

The artificial island between Germany and Denmark is beneficial for the interconnection between these two countries and allow to increase the transfer capacity.

FRANCE-GREAT BRITAIN AXIS

While the HUBs are not developed between France and Great Britain, the investment decisions are not exactly the same as for the NAT concept. This means that the chosen topology has a cross-border effect and the decisions have therefore to be coordinated at a regional level.

BELGIUM-GREAT BRITAIN AXIS

The observation made on the French-British axis is also valid for the Belgium and Great Britain interconnections.

THE NETHERLANDS-GREAT BRITAIN AXIS

The Netherlands and Great Britain benefit from a stronger interconnection via the artificial hubs. This removes the need for investment in a direct interconnector.

GERMANY/DENMARK-GREAT BRITAIN AXIS

The connection of the northern British hub to the German hub creates an interconnector from Great Britain to the German Bight. This allows to significantly reduce the length of a subsea cable able to connect these regions.

GREAT BRITAIN-NORTHERN IRELAND AND GREAT BRITAIN-IRELAND AXES

The investments in the Irish Sea are marginally influenced by the HUB concept compared to the NAT concept.

STEP 3 – SECURITY ANALYSIS

For the European Centralised Hubs concept, the security analysis depends mainly on the design of the hubs. It is assumed that a careful design of the hubs should allow to stay secure in N-1 conditions.

EUROPEAN DISTRIBUTED HUBS APPROACH

TIME EVOLUTION OF THE TOPOLOGY

In this Section, the results are illustrated for both optimisation steps. This represents a potential future topology in the North Sea for the EUR concept and the Central wind scenario. The topologies are represented from Figure 16 to Figure 18. Note that these figures represent also existing/planned interconnectors as well as existing/planned windfarms. It can be observed that the network is composed of radial and multi-terminal connections, with some meshing in specific areas such as between The Netherlands and Great Britain, and between Germany and Denmark.

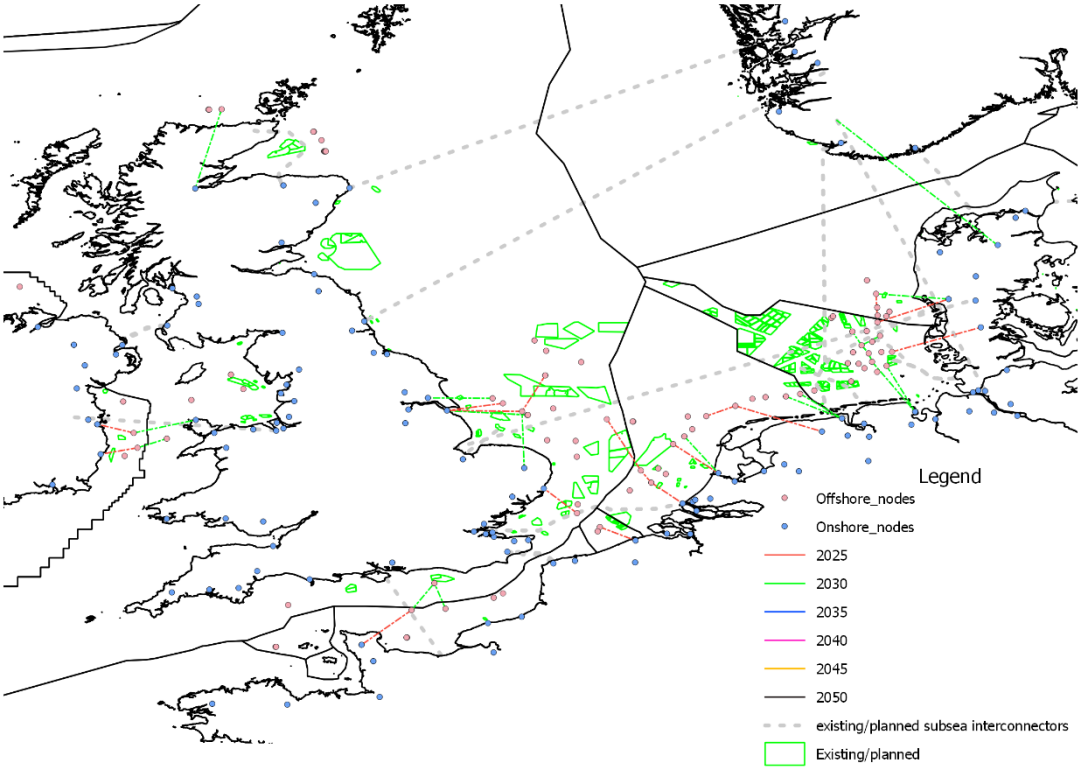


Figure 16 - Central wind scenario, EUR concept, topology in 2030.

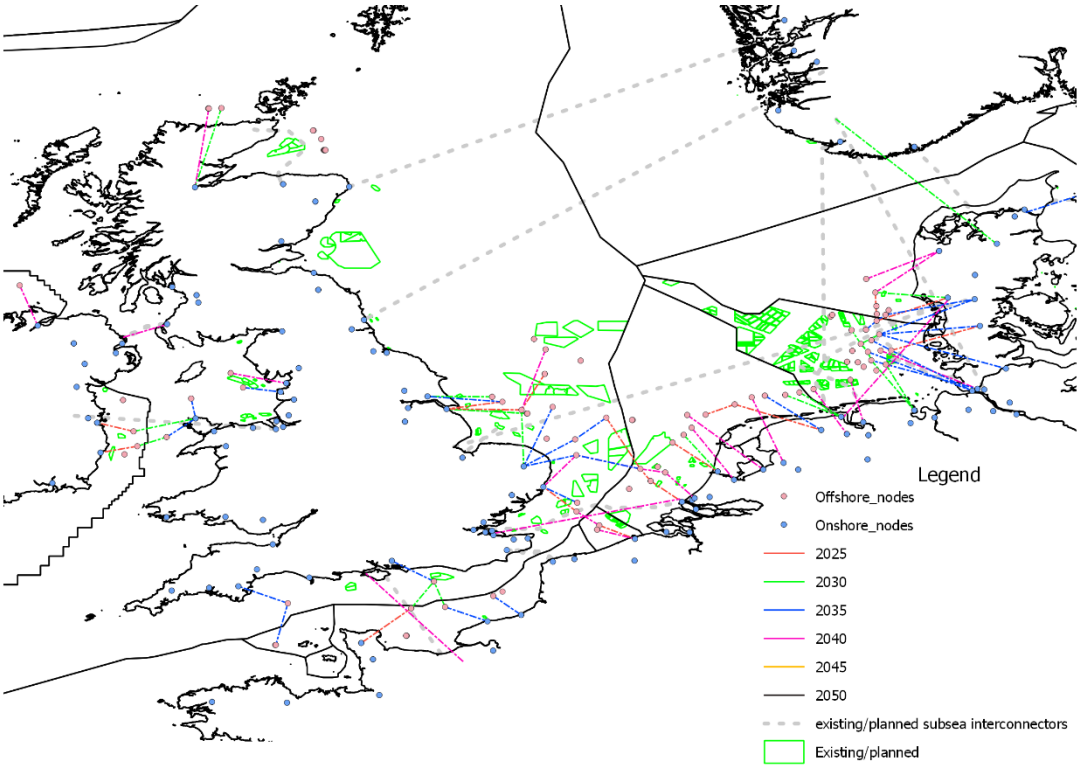


Figure 17 - Central wind scenario, EUR concept, topology in 2040.

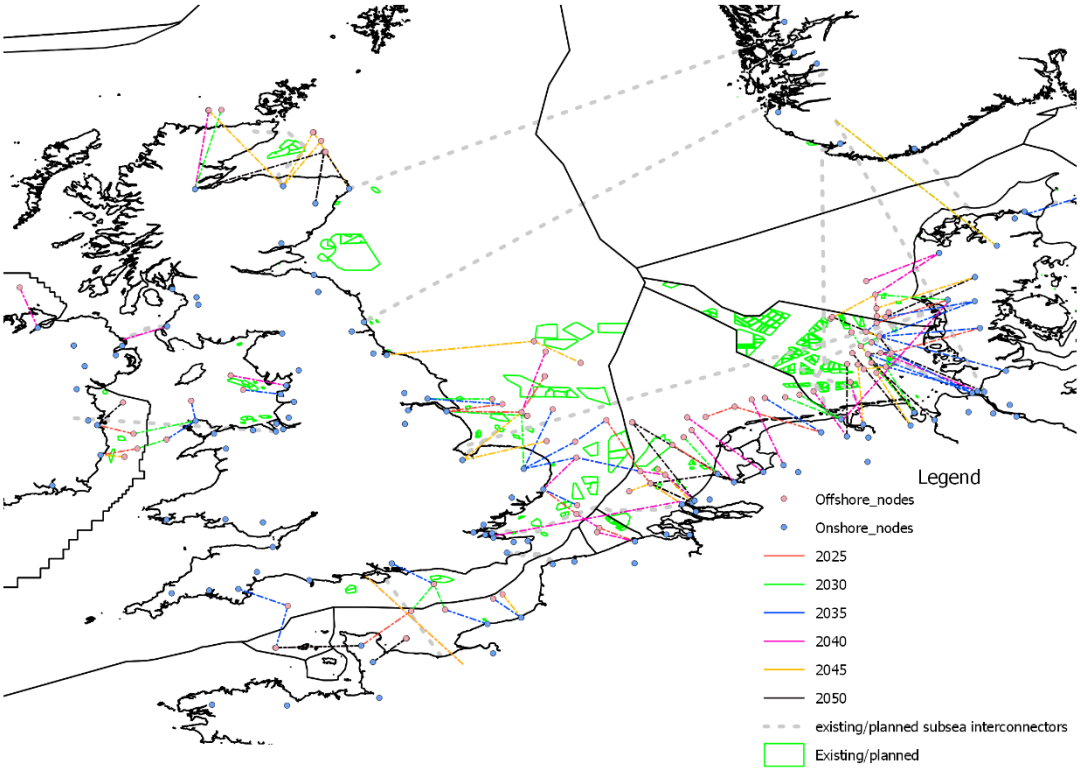


Figure 18 - Central wind scenario, EUR concept, topology in 2050.

STEP 1 - OTEP

The main observations of the OTEP step for the EUR concept Central wind scenario are the following:

Creation of multi-terminal DC connections

In the EUR case, the OTEP step tends to create multi-terminal DC grid in order to optimise the use of cable rating and therefore to minimise the cable length. This is similar to the NAT concept except that there are no national border constraints in the development of these multi-terminal structures. This is illustrated by a British wind farms connected to The Netherlands via a multi-terminal connection.

Anticipatory investments and modularity

Similarly to the BAU and NAT concept, the EUR concept requires anticipatory investments. The main difference is that the OTEP results for the EUR concept could potentially already lead to an improvement of the cross-border interconnections.

Onshore connections

Because of onshore hosting capacity constraint (maximum 4 GW per onshore connection), many onshore candidates are needed. However, the difference with the BAU and NAT concepts is that the EUR concept connects to the closest onshore node even if not from the same country.

STEP 2 - OPTIMISATION OF INTERCONNECTIONS

Table 5 lists the investments in transmission capacity expansion on the candidate interconnectors. The table allows to make the distinction between existing/planned interconnectors, expansion via direct connections or expansion via the MOG.

Table 5 - Transmission capacity expansion in the EUR concept Central wind scenario (in GW). Numbers in black are the existing/planned interconnections, numbers in red are the point-to-point expansions and in blue the expansions via the MOG.

INTERFACE	2020	2025	2030	2035	2040	2045	2050
BE-GB	1	1	1+1.2	1+1.2	1+1.2	1+1.2	1+1.2
DE-DKe	1	1	1	1	1	1+0.5	1+0.5
DE-GB	1.4	1.4	1.4	1.4	1.4	1.4	1.4
DE-NOs	1.4	1.4	1.4+2	1.4+2.2	1.4+2.6	1.4+5.4	1.4+5.6
DKw-GB	0	1.4	1.4	1.4	1.4	1.4	1.4
DKw-NL	0.7	0.7	0.7	0.7	0.7+0.6	0.7+0.6	0.7+0.6
DKw-NOs	1.6	1.6	1.6+1.2	1.6+1.7	1.6+2.1	1.6+3.5	1.6+4.0
FR-GB	4	6.8	6.8+0.5	6.8+0.5	6.8+1.8+0.7	6.8+3.9+0.7	6.8+3.9+0.7
GB-IE	0.5	0.5	0.5+1.8	0.5+1.8	0.5+2.2	0.5+2.2	0.5+2.2
GB-GB			1	1	1	1.7	1.7
GB-NI	0.5	0.5	0.5	0.5	0.5	0.5+0.9	0.5+0.9
GB-NL	1	1	1	1	1+0.7	1+2.1	1+2.1
GB-NO	0	2.8	2.8	2.8	2.8	2.8	2.8

BELGIUM-GREAT BRITAIN AXIS

The BAU investment in the direct interconnection between Belgium and Great Britain is replaced by investment via the MOG.

GERMANY-NORWAY AXIS

It can be observed that the point-to-point connection is very valuable for this study case. This is consistent with the results of the BAU and NAT concepts. This need is higher than for the High wind scenario.

GERMANY-EASTERN DENMARK AXIS

A moderate investment takes place between Germany and Eastern Denmark. This investment is similar than for the other concepts

FRANCE-GREAT BRITAIN AXIS

Similarly to the NAT case, the interconnection is composed of point-to-point interconnection and of connections via the MOG. However, the results of step 1 are different since a British wind farm is directly connected to the

French shore. This affects the investments in this second optimisation step but the overall topology stays very similar than the NAT concept.

GREAT BRITAIN-THE NETHERLANDS AXIS

The investments between The Netherlands and Great Britain are very comparable to the investments between France and Great Britain. Some British wind farms are connected to The Netherlands via multi-terminal HVDC connections. However, it is seen as economic to connect British wind farms to each other (UK_OFF73 and UK_OFF70) to make use of the multi-terminal as interconnector. Refer to Figure 19.

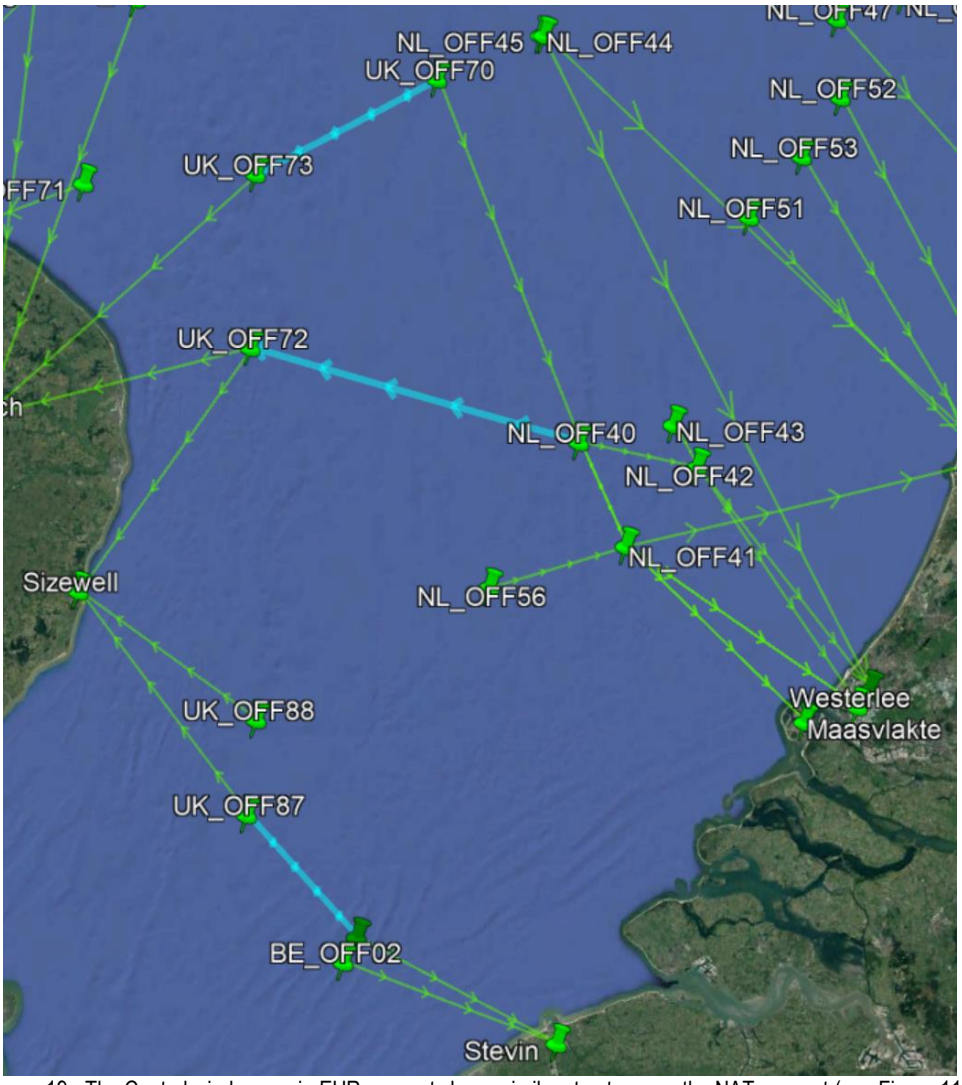


Figure 19 - The Central wind scenario EUR concept shows similar structures as the NAT concept (see Figure 11).

GREAT BRITAIN-NORTHERN IRELAND AND GREAT BRITAIN-IRELAND AXES

The investments in the Irish Sea are similar as in the NAT concept.

STEP 3 - SECURITY ANALYSIS

In the EUR case, load flow analyses in the healthy state (no outage) were performed for each target year at maximum wind production. No overload or overvoltage of equipment was observed.

In N-1, droop control is required to avoid over-voltages post-contingency. Special protection schemes might also be need to initiate fast control actions post-contingency to avoid overloads. This is similar to the NAT case.

CABLE LENGTH REQUIRED

Figure 20 illustrates the total cable length require for building the proposed topologies. In other words, around 13000 km of cables are required to evacuate wind at the studied locations. This is significantly less than the High wind scenario and can be explained by the fact that the Dogger Bank is not exploited.

For evacuating the wind energy (step 1), the NAT concept performs the best and allows to reduce the total cable length by 7% compared to the BAU. The EUR concept has similar performance with a length reduction of around 6% compared to the BAU.

For the optimisation of the interconnector step, it is the HUB concept which performs the best with a 25% length reduction compared to BAU. In total, around 3000 km of interconnectors (in addition to planned IC from TYNDP) are required in the BAU. The NAT and EUR concept allow respectively a length reduction of 14% and 17% compared to the BAU.

In total, the cable length for the Central wind scenario can be reduced by around 7% using the NAT or EUR concept, and by 5% using the HUB concept.

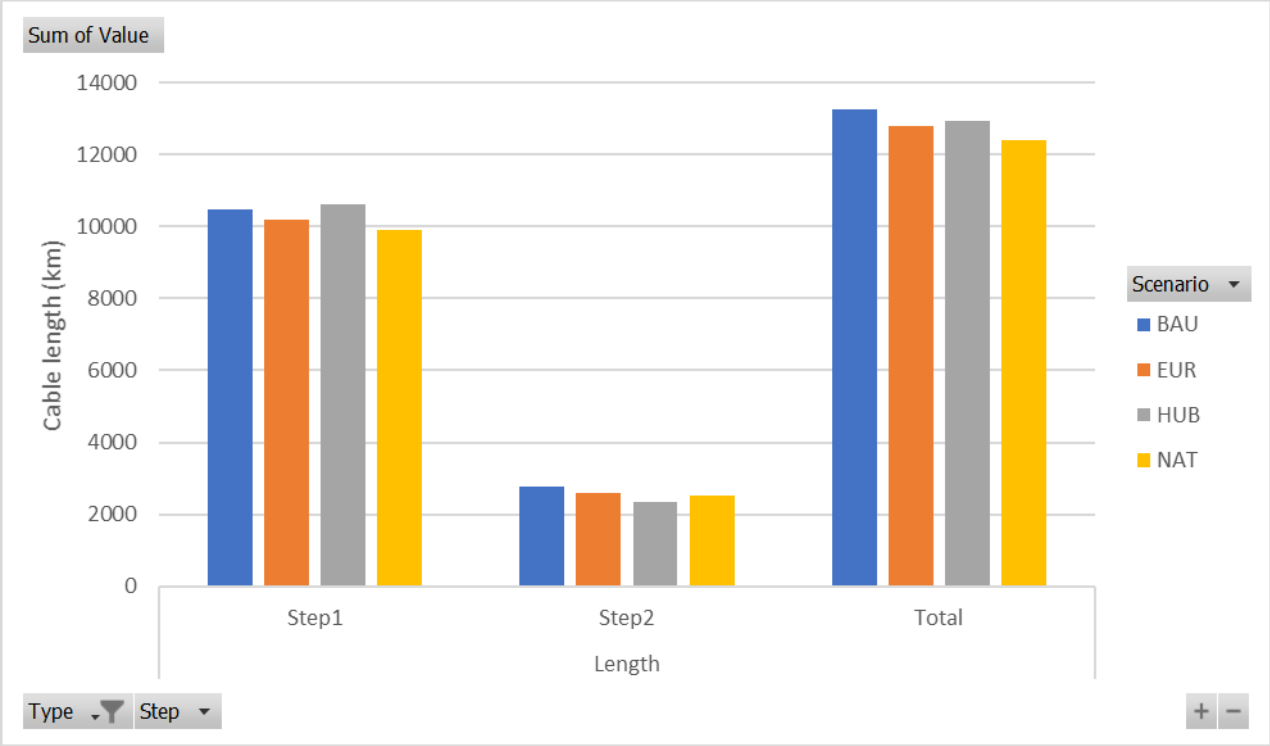


Figure 20 - Comparison of total cable length for the Central wind scenario.

TOPOLOGY GENERATION RESULTS FOR THE LOW WIND SCENARIO

The results will be presented successively for each of the four concepts for the Low wind scenario. This scenario assumes a total offshore installed capacity of around 100 GW in 2050 (which is 50% less than in the High wind scenario). In the Low wind scenario, all the offshore wind farms are located relatively close to shore.

For each concept, the results of the whole optimisation process are first shown for each optimisation time step (i.e. 5-year interval). This illustrates the potential development of the offshore grid from 2025 to 2050 for the Low wind scenario. Then, the observations of the step 1 (OTEP) are described followed by the results of the optimisation of the interconnection. Next, a short Section on recommendations drawn from the security analysis takes place. Finally, a Section compares the different concepts.

BUSINESS-AS-USUAL APPROACH

TIME EVOLUTION OF THE TOPOLOGY

For the sake of clarity, the results are first illustrated for both optimisation steps. This represents a potential future topology in the North Sea for the BAU concept and the Central wind scenario. The topologies are represented in from Figure 21 to Figure 23. Note that these figures represent also existing/planned interconnectors as well as existing/planned windfarms.

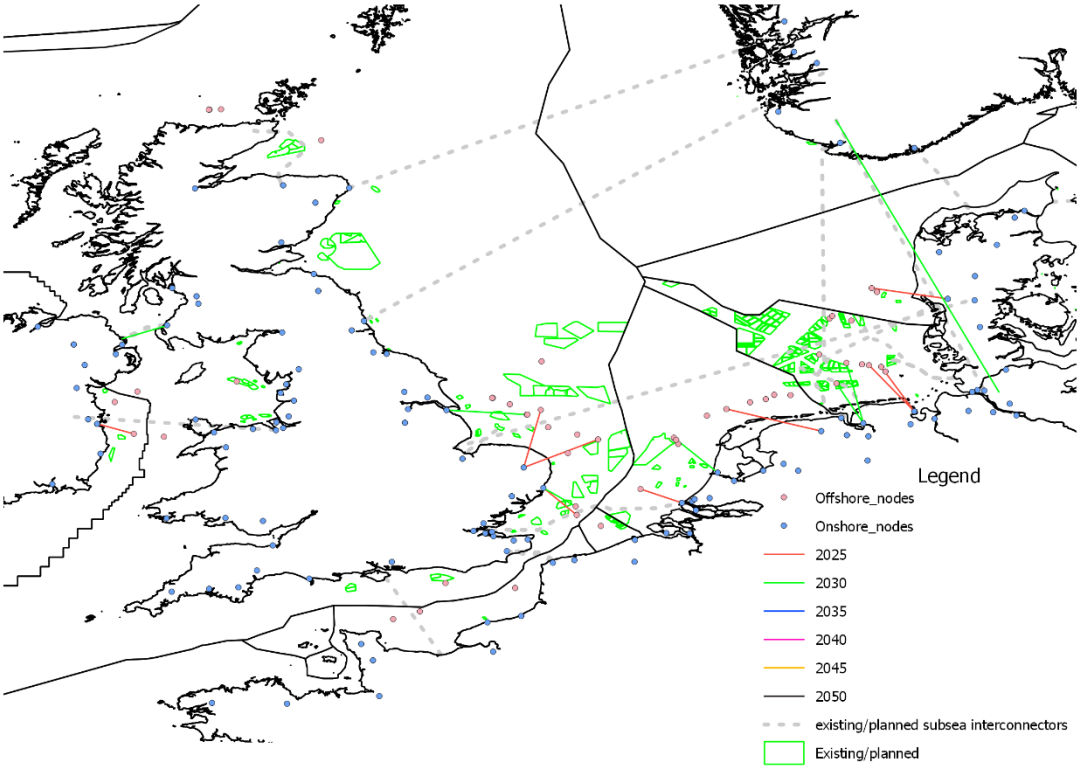


Figure 21 - Low wind scenario, BAU concept, topology in 2030.

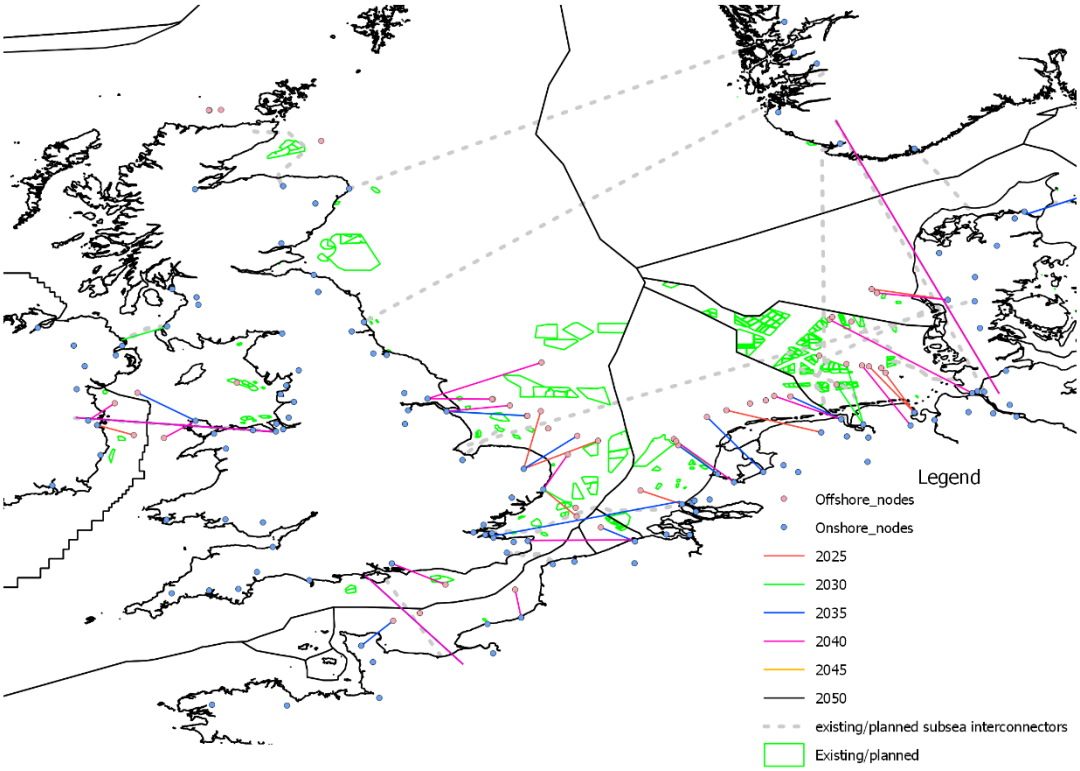


Figure 22 - Low wind scenario, BAU concept, topology in 2040.

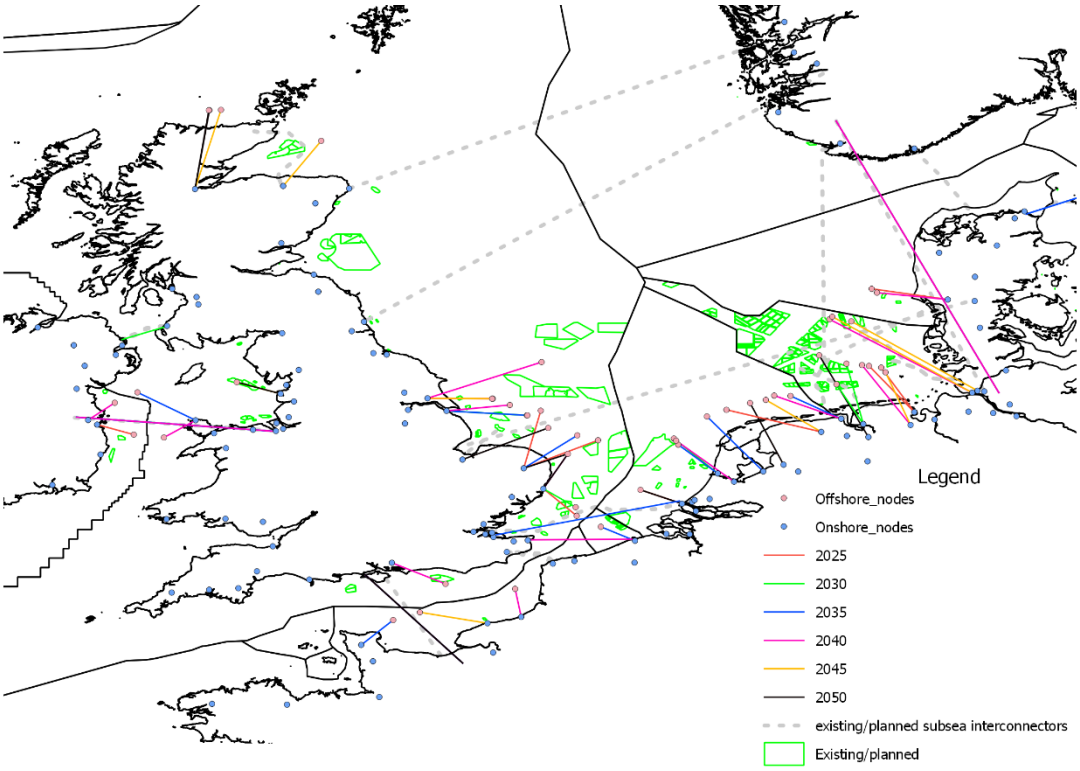


Figure 23 - Low wind scenario, BAU concept, topology in 2050.

STEP 1 - OTEP

The main observations resulting from the OTEP step for the BAU concept Low wind scenario are the following:

Onshore connections

In the BAU case, the OTEP step tends to connect the offshore nodes to the closest onshore points. Because of onshore hosting capacity constraint (maximum 4 GW per onshore connection), many onshore candidates are needed. However, because of the much lower offshore wind capacity exploited, this constraint impacts less the results and most of the windfarms can be connected to their closest onshore point.

Anticipatory investment (temporary oversizing of cables)

The cable capacities are optimised for a 10-year horizon. Therefore, some cables are oversized for some target years in order to accommodate future offshore wind production

STEP 2 - OPTIMISATION OF INTERCONNECTIONS

In the BAU approach, the candidate interconnectors are only from shore to shore. The expansions can be seen in Table 6. It can be observed that the investments are significantly higher than in the High wind scenario. This illustrates that the need for interconnection comes from the whole energy mix and not only from offshore wind.

Table 6 - Transmission capacity expansions for BAU concept (GW) Central wind scenario. Numbers in black are the existing/planned interconnections, numbers in red are the point-to-point expansions.

INTERFACE	2020	2025	2030	2035	2040	2045	2050
BE-GB	1	1	1	1	1+0.7	1+0.7	1+0.7
DE-DKe	1	1	1	1	1+1	1+1.8	1+1.8
DE-GB	1.4	1.4	1.4	1.4	1.4	1.4	1.4
DE-NOs	1.4	1.4	1.4+1.9	1.4+3.5	1.4+7.3	1.4+8.1	1.4+8.1
DKw-GB	0	1.4	1.4	1.4	1.4	1.4	1.4
DKw-NL	0.7	0.7	0.7	0.7	0.7	0.7	0.7
DKw-NOs	1.6	1.6	1.6	1.6+1.2	1.6+1.5	1.6+1.8	1.6+1.8
FR-GB	4	6.8	6.8	6.8+2.9	6.8+4.3	6.8+5.9	6.8+10
GB-IE	0.5	0.5	0.5	0.5+3.3	0.5+5.2	0.5+5.5	0.5+6.1
GB-NI	0.5	0.5	0.5	0.5+0.8	0.5+0.8	0.5+0.8	0.5+0.8
GB-NL	1	1	1	1	1	1	1+0.7
GB-NO	0	2.8	2.8	2.8	2.8	2.8	2.8

The following observations are made on the BAU model. These observations result from an optimisation trying to reduce the overall operation costs by investing in the least-cost candidate transmission lines. In the BAU model,

the candidates for transmission expansion are direct connections from one country to another. There is no transmission candidate from an offshore point.

GERMANY-NORWAY AXIS

The Low wind scenario sees a very significant need for interconnection between Norway and Germany. This is due to the high PV penetration in Germany and the fact that daily PV production can easily be stored in the Norway hydro reservoirs. However, a more complete study on multiple climate years is needed to confirm this observation.

GERMANY-EASTERN DENMARK AXIS

The investment decisions between Germany and East-Denmark are similar than for the High wind scenario.

BELGIUM-GREAT BRITAIN AND THE NETHERLANDS-GREAT BRITAIN AXES

These two interconnections are moderately reinforced for the Low wind scenario. This is different than for the High wind scenario. In particular, there is much less investments in the Dutch-British connection than for the High wind scenario. This might be due to the lower offshore wind production in The Netherlands.

FRANCE-GREAT BRITAIN AXIS

The France to Great Britain interconnection is strongly reinforced in the Low wind scenario. An additional 10 GW in 2050 is seen as economic to exchange energy between these two countries.

GREAT BRITAIN-NORTHERN IRELAND AND GREAT BRITAIN-IRELAND AXES

The interconnection candidates between Great Britain on one side, Ireland and Northern Ireland on the other side trigger an investment of 1200 MW to Northern Ireland and of almost 6 GW to Ireland.

CONGESTIONS ON THE COUNTRY-TO-COUNTRY INTERCONNECTIONS OF THE TYNDP

Several interconnections of the TYNDP model congest during a significant share of the years from 2020 to 2050. This observation is similar as for the High and Central wind scenarios.

STEP 3 - SECURITY ANALYSIS

In the BAU case, the N-1 security analysis leads to loss of power infeed. By design, there are no cases where the consequence of fault spreads to the rest of the MOG.

NATIONAL DISTRIBUTED HUBS APPROACH

TIME EVOLUTION OF THE TOPOLOGY

In this Section, the results are illustrated for both optimisation steps. This represents a potential future topology in the North Sea for the NAT concept and the Low wind scenario. The topologies are represented in Figure 24 to Figure 26. Note that these figures represent also existing/planned interconnectors as well as existing/planned windfarms. It can be observed that the network is composed mainly of radial and multi-terminal connections. There is no real “mesh” in the Low wind scenario but some multi-terminal connections are use as interconnectors.

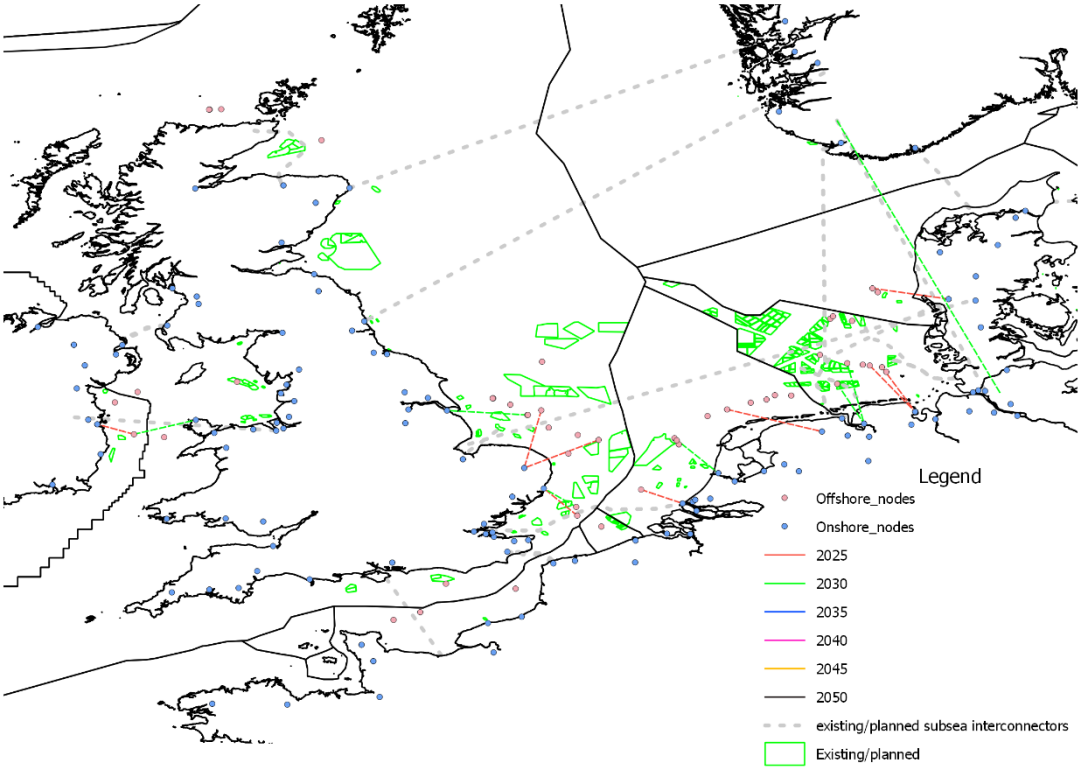


Figure 24 - Low wind scenario, NAT concept, topology in 2030.

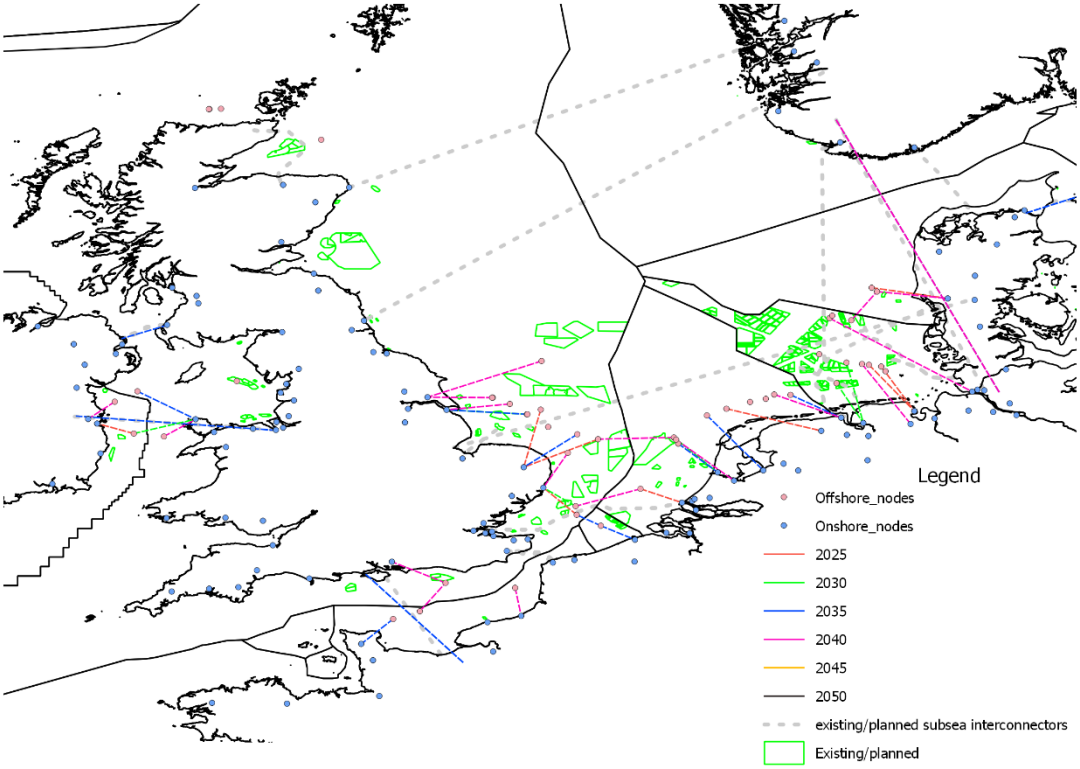


Figure 25 - Low wind scenario, NAT concept, topology in 2040.

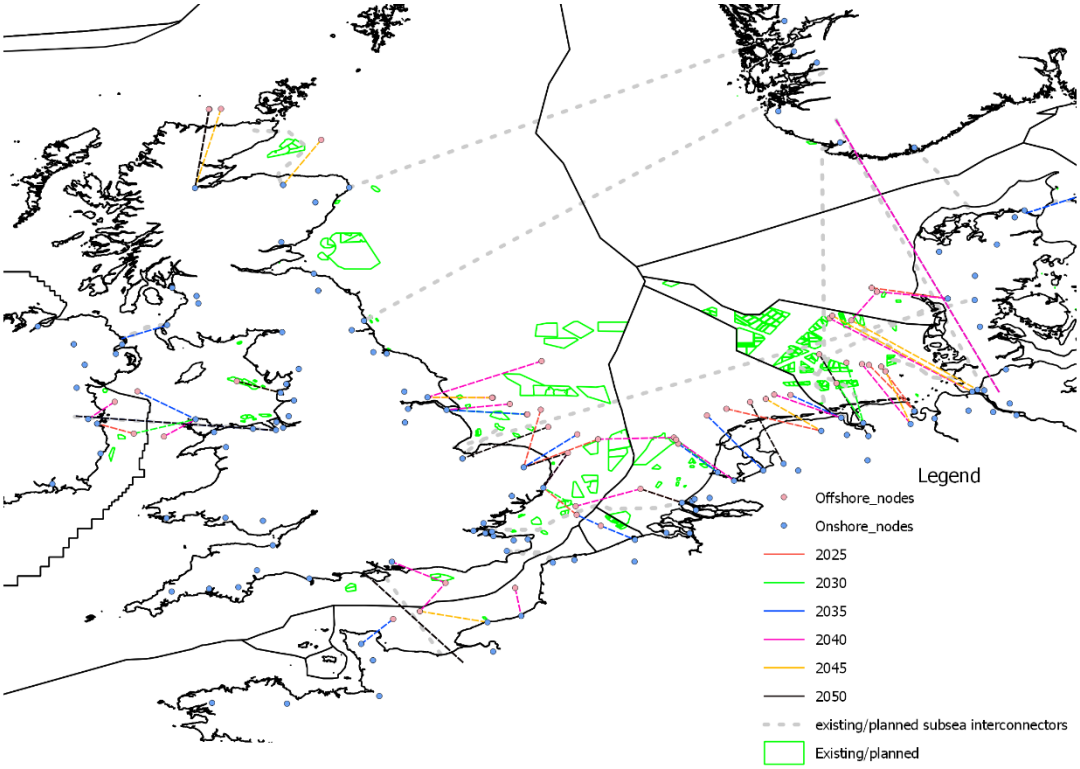


Figure 26 - Low wind scenario, NAT concept, topology in 2050.

STEP 1 - OTEP

The observations of the OTEP step are similar to what was already observed for other scenarios. However, the difference between the concepts is less clear in the Low wind scenario.

Creation of multi-terminal DC connections

In the NAT case, the OTEP step tends to create multi-terminal DC grid in order to optimise the use of cable rating and therefore to minimise the cable length. The multi-terminal DC grids can be found at some specific locations and are influenced by the locations of the wind farms and by their expected expansion. Therefore, a coordination planning of the transmission investments and OWF development is required.

Anticipatory investments and modularity

Similarly to the BAU concept, the NAT concept requires anticipatory investments. Therefore, cables might be oversized for some target years or the multi-terminal connections can be created in order to facilitate future wind generation. The multi-terminal connections might also create more connection options for future wind farms which bring modularity in the development of the MOG.

Onshore connections

Because of onshore hosting capacity constraint (maximum 4 GW per onshore connection), many onshore candidates are needed. However, the difference with the BAU concept is that in some cases, a multi-terminal connection is used to reach an onshore point with sufficient hosting capacity.

STEP 2 - OPTIMISATION OF INTERCONNECTIONS

Table 7 lists the investments in transmission capacity expansion on the candidate interconnectors. The candidates without investment are removed from the table. Country-to-country interconnection capacity investments are allowed from 2030 on. The offshore interconnection investments are allowed from 2025 on.

Table 7 - Transmission capacity expansion in the NAT concept Low wind scenario (in GW). Numbers in black are the existing/planned interconnections, numbers in red are the point-to-point expansions and in blue the expansions via the MOG.

INTERFACE	2020	2025	2030	2035	2040	2045	2050
BE-GB	1	1	1	1+1	1+1	1+1	1+1
BE-NL					0.7	0.7	0.7
DE-DKe	1	1	1	1	1+0.7	1+1	1+1
DE-DKw						0.7	0.7
DE-GB	1.4	1.4	1.4	1.4	1.4	1.4	1.4
DE-NL				0.8	3.2	3.2	3.2
DE-NOs	1.4	1.4	1.4+1.9	1.4+3.4	1.4+7.4	1.4+7.4	1.4+7.4
DKw-NOs	1.6	1.6	1.6	1.6+1.1	1.6+2.9	1.6+3.4+1.1	1.6+3.4+1.1
FR-GB	4	6.8	6.8	6.8+2.9	6.8+4.1+0.6	6.8+5.5+0.6	6.8+9.2+0.6
GB-IE	0.5	0.5	0.5	0.5+1.9+0.7	0.5+3.7+0.7	0.5+3.7+0.7	0.5+4.3+0.7
GB-NI	0.5	0.5	0.5	0.5	0.5+0.6	0.5+0.6	0.5+0.6
GB-NL	1	1	1	1	1+1.1	1+1.9	1+2.4
GB-NOs	0	2.8	2.8	2.8	2.8	2.8	2.8

BELGIUM-GREAT BRITAIN AXIS

The MOG allows to have a more economic investment than in the BAU case. This observation is valid for all wind scenarios.

GERMANY-NORWAY AXIS

The direct connection from Germany to Norway is less expanded in the NAT concept. This can be explained by the investments in the German Bight between German and Danish wind farms as well as investments on the direct interconnection between Denmark West and Norway. However, there is still a significant need for the direct interconnector between Germany and Norway.

FRANCE-GREAT BRITAIN AXIS

The investments on the France to Great Britain interconnections are slightly lower than in the BAU case but the use of the MOG is limited in the Low wind scenario. Therefore, the investments on the direct interconnection is relatively similar than in the BAU concept.

GREAT BRITAIN-NORTHERN IRELAND AND GREAT BRITAIN-IRELAND AXES

The use of multi-terminal offshore DC connections allows to reduce the investments in the direct interconnectors. However, in the Low wind scenario, the need for direct interconnection is still very important.

CONGESTIONS ON THE COUNTRY-TO-COUNTRY INTERCONNECTIONS OF THE TYNDP

The congestions of the onshore connections of the BAU model are partly solved by the opportunities to develop the offshore interconnections between the Netherlands and Germany, between Belgium and The Netherlands, and between Germany and Denmark West.

STEP 3 - SECURITY ANALYSIS

In the NAT case, load flow analyses in the healthy state (no outage) were performed for each target year at maximum wind production. No overload or overvoltage of equipment was observed.

In N-1, droop control is required to avoid over-voltages post-contingency. Special protection schemes might also be need to initiate fast control actions post-contingency to avoid overloads.

EUROPEAN CENTRALISED HUBS APPROACH

TIME EVOLUTION OF THE TOPOLOGY

This Section illustrates the evolution of the topology for the HUB concept Low wind scenario from 2025 to 2050. Four artificial islands have been considered and are at the same locations as for the Central wind scenario. Results can be seen in Figure 27 to Figure 29. It can be observed that the three islands located closer to shore are used and are interconnected to form a path from Great Britain to Denmark via the MOG.

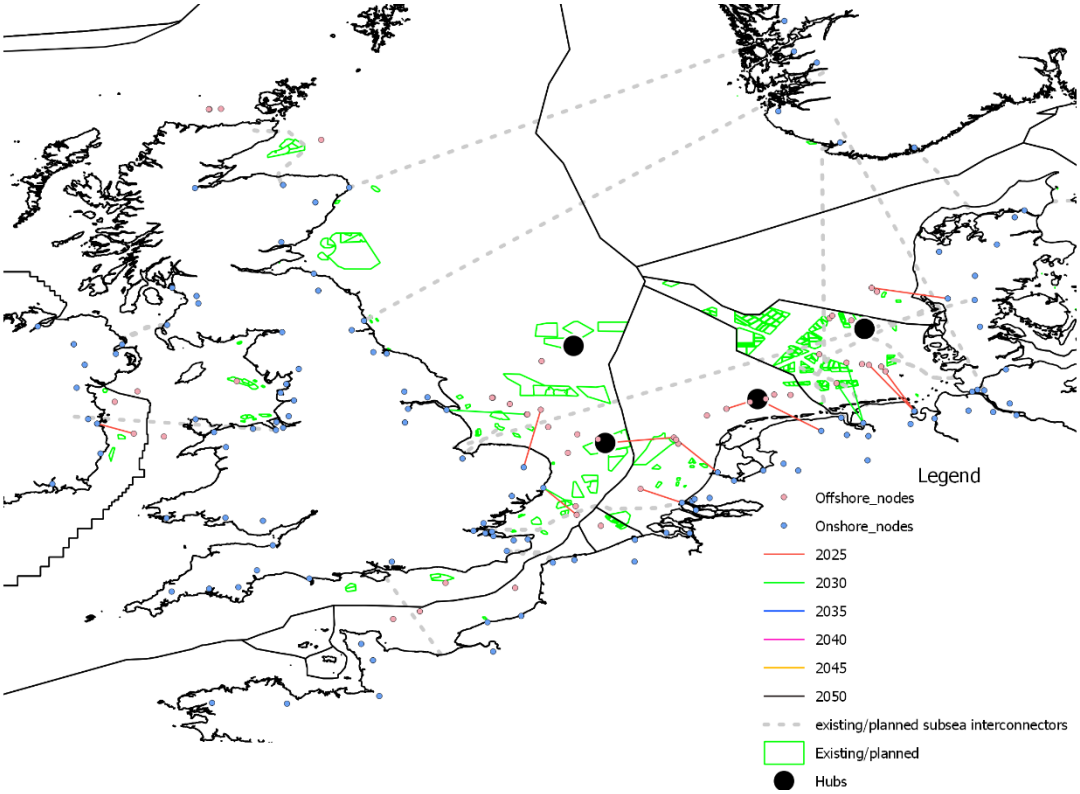


Figure 27 - Low wind scenario, HUB concept, topology in 2030.

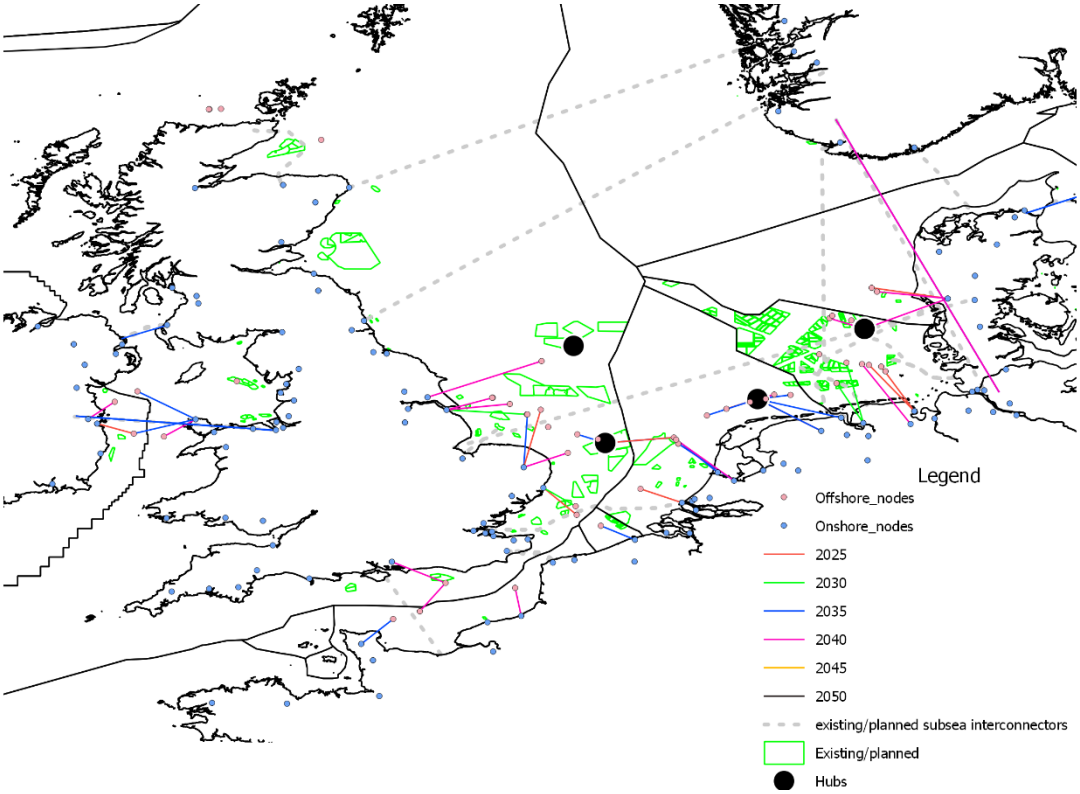


Figure 28 - Low wind scenario, HUB concept, topology in 2040.

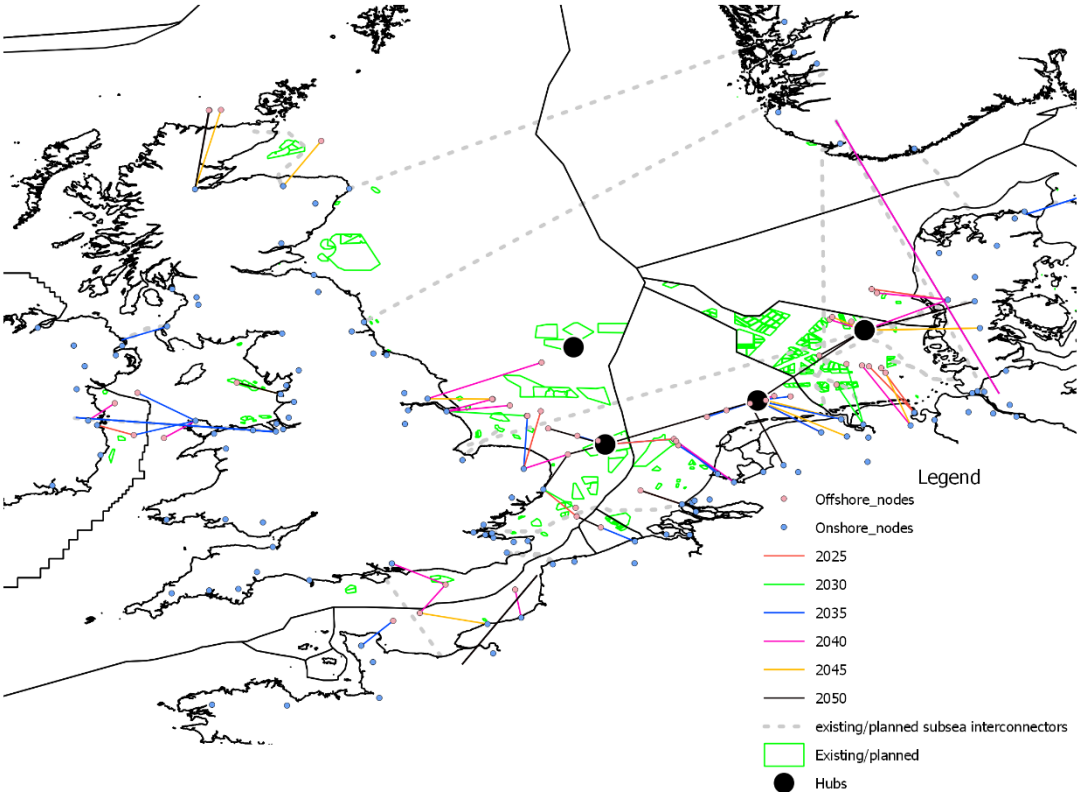


Figure 29 - Low wind scenario, HUB concept, topology in 2050.

STEP 1 - OTEP

The observations from the OTEP step are similar than for the two other wind scenarios.

AC-connection to hub

In the European Centralised Hubs concept, four artificial islands are considered. However, it can be observed in the Low wind scenario that many wind farms are directly connected to shore. This can be explained by the shorter distance between the wind farms and the shore compared to the other wind scenarios.

DC connection to shore and between islands

The connections to shore and between islands are done only in DC. The main benefits in the Low wind scenario might be the possibility to create an electrical path crossing the North Sea using the artificial islands.

Multi-terminal DC connection

For windfarms located between shore and an island, it might be interesting to connect them using a multi-terminal DC connection between the island, the windfarm and the shore.

STEP 2 - OPTIMISATION OF INTERCONNECTIONS

Table 8 lists the investments in transmission capacity expansion on the candidate interconnectors.

Table 8 - Transmission capacity expansion in the HUB concept Low wind scenario (in GW). Numbers in black are the existing/planned interconnections, numbers in red are the point-to-point expansions and in blue the expansions via the MOG

INTERFACE	2020	2025	2030	2035	2040	2045	2050
BE-GB	1	1	1	1	1	1	1+1

DE_hub-NL_hub							0.1
DE-DKe	1	1	1	1	1+0.7	1+1.1	1+2.0
DE-GB	1.4	1.4	1.4	1.4	1.4	1.4	1.4
DE-Nos	1.4	1.4	1.4	1.4+2.4	1.4+7.9	1.4+7.9	1.4+7.9
DKw-GB	0	1.4	1.4	1.4	1.4	1.4	1.4
DKw-NL	0.7	0.7	0.7	0.7	0.7	0.7	0.7
DKw-NOs	1.6	1.6	1.6+2	1.6+2	1.6+3	1.6+4	1.6+4
FR-GB	4	6.8	6.8	6.8	6.8+0.6	6.8+0.6	6.8+0.6+8
GB-IE	0.5	0.5	0.5+0.6	0.5+3.6+1.8	0.5+3.6+1.8	0.5+3.6+1.8	0.5+3.6+1.8
GB-NI	0.5	0.5	0.5	0.5+0.4	0.5+0.4	0.5+0.4	0.5+0.4
GB-NL	1	1	1	1	1	1	1
GB-NO	0	2.8	2.8	2.8	2.8	2.8	2.8
NL_hub-GB_hub							0.1

The HUB concept leaves the possibility of investing between the HUBs located in the North Seas to interconnect the countries. The candidate lines in the Irish Sea and in The Channel are similar to the NAT concept.

GERMANY-NORWAY AND WEST DENMARK-NORWAY AXES

Similarly to the other concepts, the direct connection from Germany to Norway is highly economic in the Low wind scenario. The same observation is valid for West Denmark to Norway.

GERMANY-EASTERN DENMARK AXIS

The connection between Germany and Eastern Denmark is reinforced by two additional GW in 2050. This is the same order of magnitude as in the BAU concept

FRANCE-GREAT BRITAIN AXIS

The HUBs are not developed between France and Great Britain. The results show that the total investments in 2050 are similar to investments in the NAT concept.

GREAT BRITAIN, THE NETHERLANDS, GERMANY TO WEST DENMARK VIA HUBS

By looking at the illustrative maps presented in the first Section, this interconnection via the MOG seemed very interesting. The numbers show that only a limited investment is seen as economic with our input assumptions. While this might not be the expected results, it outlines that there might be a business case for the HUB concept, even in the Low wind scenario.

GREAT BRITAIN-NORTHERN IRELAND AND GREAT BRITAIN-IRELAND AXES

The investments in these two axes are similar to the EUR concept and are therefore not significantly impacted by the hub topology in the North Sea.

STEP 3 - SECURITY ANALYSIS

For the European Centralised Hubs concept, the security analysis depends mainly on the design of the hubs. It is assumed that a careful design of the hubs should allow to stay secure in N-1 conditions.

EUROPEAN DISTRIBUTED HUBS APPROACH

TIME EVOLUTION OF THE TOPOLOGY

In this Section, the results are illustrated for both optimisation steps. This represents a potential future topology in the North Sea for the EUR concept and the Low wind scenario. The topologies are represented in Figure 30 to Figure 32. Note that these figures represent also existing/planned interconnectors as well as existing/planned windfarms. It can be observed that the network is composed of radial and cross-border multi-terminal connections, in particular between The Netherlands and Great Britain.

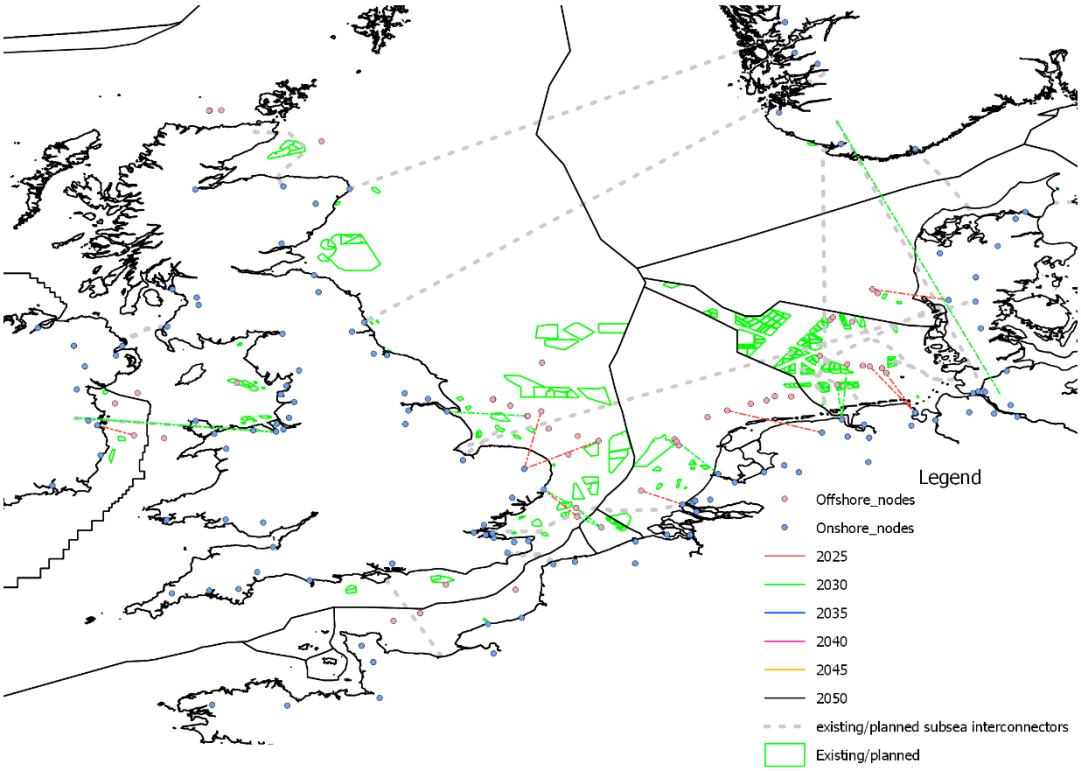


Figure 30 - Low wind scenario, EUR concept, topology in 2030.

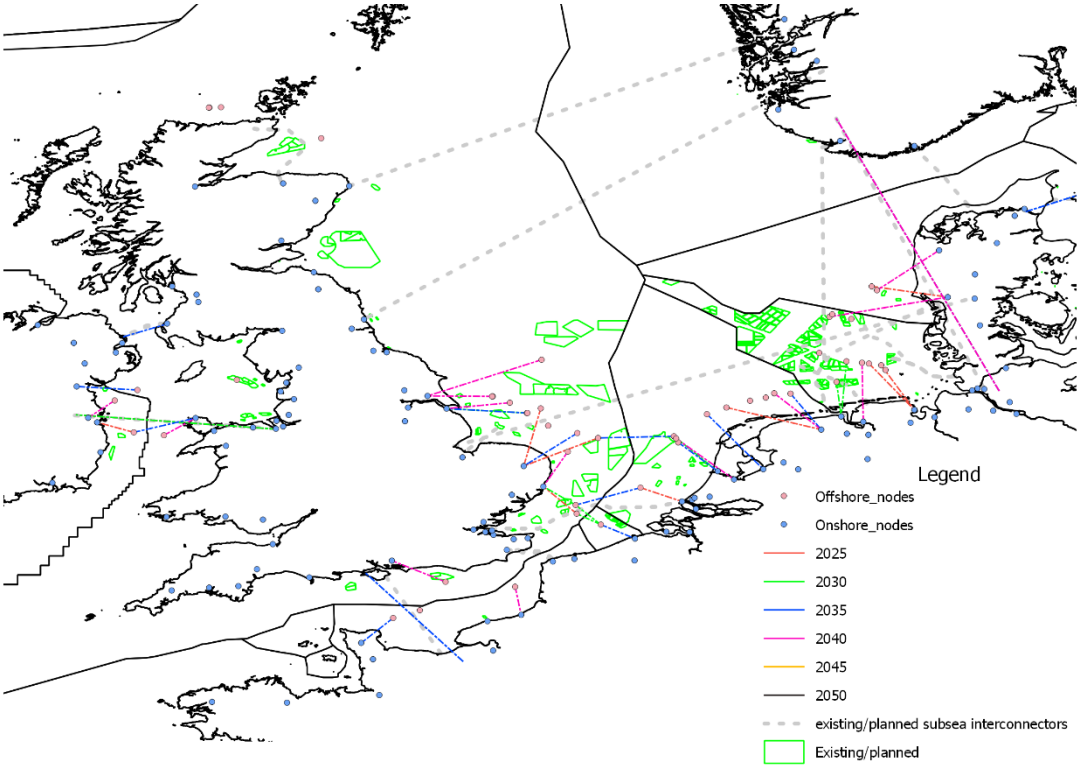


Figure 31 - Low wind scenario, EUR concept, topology in 2040.

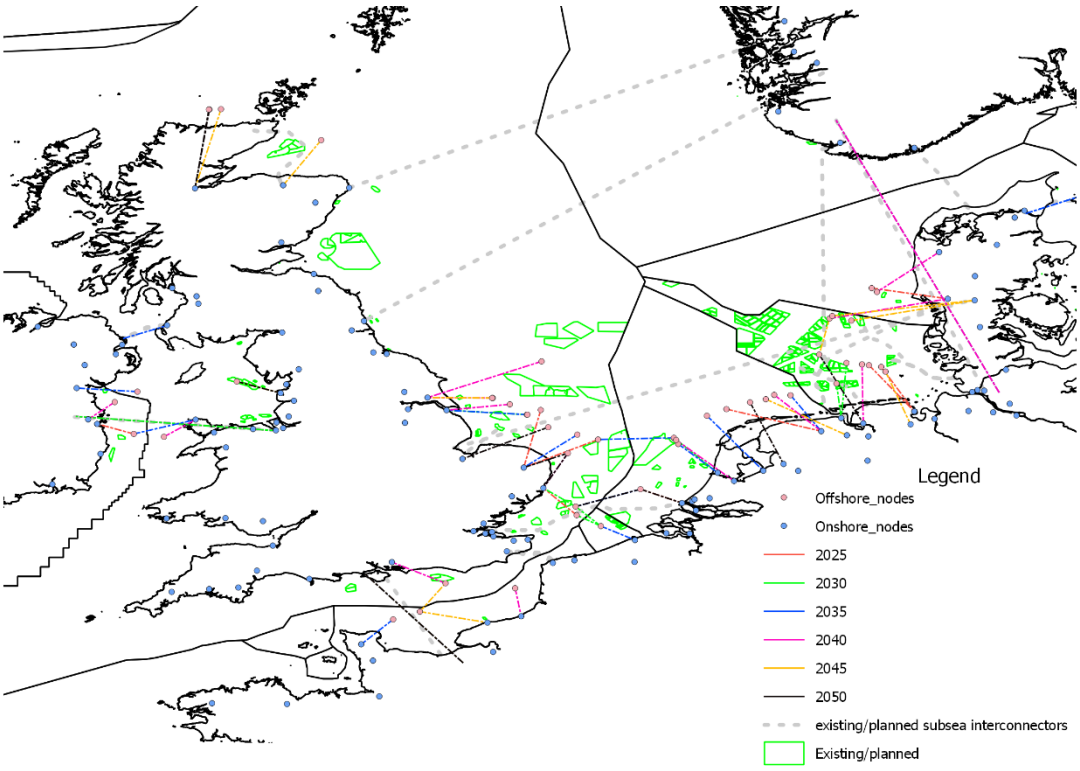


Figure 32 - Low wind scenario, EUR concept, topology in 2050.

STEP 1 - OTEP

The OTEP step for the EUR concept, Low wind scenario brings similar observations than the NAT concept.

Creation of multi-terminal DC connections

In the EUR case, the OTEP step tends to create multi-terminal DC grid in order to optimise the use of cable rating and therefore to minimise the cable length. This is similar to the NAT concept except that there are no national border constraints in the development of these multi-terminal connections.

Anticipatory investments and modularity

Similarly to the BAU and NAT concept, the EUR concept requires anticipatory investments. The main difference is that the OTEP results for the EUR concept could potentially already lead to an improvement of the cross-border interconnections.

Onshore connections

Because of onshore hosting capacity constraint (maximum 4 GW per onshore connection), many onshore candidates are needed. However, the difference with the BAU and NAT concepts is that the EUR concept connects to the closest onshore node even if not from the same country. This can be observed in the German Bight where a German wind farm is connected to Denmark.

STEP 2 - OPTIMISATION OF INTERCONNECTIONS

Table 9 lists the investments in transmission capacity expansion on the candidate interconnectors.

Table 9 - Transmission capacity expansion in the EUR concept Low wind scenario (in GW). Numbers in black are the existing/planned interconnections, numbers in red are the point-to-point expansions and in blue the expansions via the MOG.

INTERFACE	2020	2025	2030	2035	2040	2045	2050
BE-GB	1	1	1+1.4	1+1.4	1+1.4	1+2.7	1+2.7
DE-DE						2	2
DE-DKe	1	1	1	1	1+1.2	1+1.2	1+1.2
DE-GB	1.4	1.4	1.4	1.4	1.4	1.4	1.4
DE-NOs	1.4	1.4	1.4+1.9	1.4+3.2	1.4+7.9	1.4+7.9	1.4+7.9
DKw-NOs	1.6	1.6	1.6	1.6+1.1	1.6+3.3	1.6+3.3+1.5	1.6+3.3+1.5
FR-GB	4	6.8	6.8	6.8+2.7	6.8+4+0.7	6.8+5.4+0.7	6.8+8.3+0.7
GB-IE	0.5	0.5	0.5+1.8	0.5+1.8	0.5+4.3+1.8	0.5+4.3+1.8	0.5+4.9+1.8
GB-NI	0.5	0.5	0.5	0.5	0.5+0.6	0.5+0.6	0.5+0.6
GB-NL	1	1	1+2.5	1+2.5	1+2.5	1+3.8	1+3.8
GB-NOs	0	2.8	2.8	2.8	2.8	2.8	2.8

BELGIUM-GREAT BRITAIN AND THE NETHERLANDS-GREAT BRITAIN AXES

It can be observed that the MOG interconnects these three countries in the EUR concept. Therefore, the transfer capacities can be increased to/from Great Britain but also between Belgium and The Netherlands. This is why there is significantly more investment than in the NAT concept.

GERMANY-NORWAY AXIS

The direct connection Germany-Norway has fewer investments than in the BAU concept thanks to the use of the MOG and of the direct connection Denmark West-Norway. However, the direct connection from Germany to Norway stays the principal means for exchanging energy between these two countries.

GERMANY-EASTERN DENMARK AXIS

The connection of Germany and Eastern Denmark is reinforced by 1.2 GW in 2040, similar to the NAT concept.

FRANCE-GREAT BRITAIN AXIS

Similarly to the NAT case, the BAU investment in the country-to-country interconnection from France to Great Britain is reduced by investment using the MOG. However, the exchanges via the direct connection are significantly higher than via the MOG.

GREAT BRITAIN-NORTHERN IRELAND AND GREAT BRITAIN-IRELAND AXES

Multi-terminal connections in the Irish Sea allow to reduce the investment on the point-to-point interconnection between Great Britain and Ireland. The interconnection between Great Britain and Northern Ireland is exclusively via a direct link.

STEP 3 - SECURITY ANALYSIS

In the EUR case, load flow analyses in the healthy state (no outage) were performed for each target year at maximum wind production. No overload or overvoltage of equipment was observed.

In N-1, droop control is required to avoid over-voltages post-contingency. Special protection schemes might also be need to initiate fast control actions post-contingency to avoid overloads. This is similar to the NAT case.

CABLE LENGTH REQUIRED

The Low wind scenario accommodates around 100 GW of offshore wind. This would require around 5000 km of cables to evacuate wind (as shown in Figure 33). Due to the proximity to shore of most of the wind farms, the differences between the concepts are much less significant than for the other wind scenarios. For example, the NAT concept does not reduce the total cable length compared to the BAU while the EUR concept reduces the total cable length by 4%.

The second optimisation step shows that around 5000 km of interconnectors (in addition to planned IC from TYNDP) are deemed as economic. This is significantly higher than for the Central and High wind scenarios and outlines that there is a need to reinforce interconnection between countries for all wind scenarios. Overall the EUR concept performs the best but allows a length reduction of only 3% compared to the BAU concept.

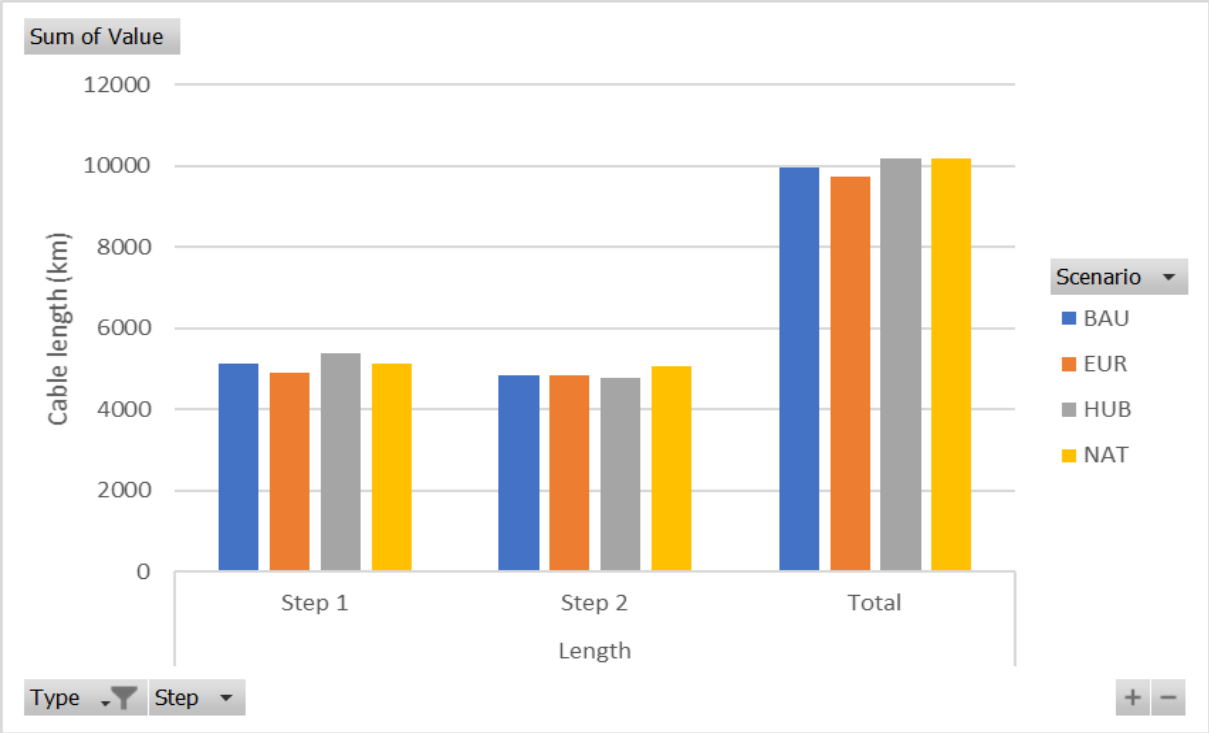


Figure 33 - Comparison of total cable length for the Low wind scenario.

APPENDIX IV

COST DATA COLLECTION METHODOLOGY

This analysis has been done according to the steps in Figure 34.

Figure 34 - Main work flow of the cost data collection.

As there is limited information and the information has to be accepted within the consortium, these steps are defined:

1. **Data collection**: Data is collected from public, scientific and DNV GL internal sources. In case there is no information available, bottom up approaches are used to define cost figures based on other components.
2. **Data validation**: The results of the model are validated through public sources of existing projects. These projects include offshore wind connections and interconnections.
3. **Data verification**: The results of the analysis are checked with vendors. This is done by confidential interviews in which the vendors give generic feedback on the figures.

DATA COLLECTION

As stated in [59], the methodology for cost data collection has been different depending on the type of components, which are all summarised in Figure 35:

1. **Mature products**, such as cables, HB VSC HVDC converter stations and AC transformers. The underlying technologies have been developed continuously over the past couples of decades, the products have been deployed in a significant number of projects worldwide, and there are several vendors competing in the market. For this category of products, the cost data will be collected through publicly available sources (literature, published contract values) and augmented with in-house data from the TSOs.
2. **Products are under development, but other products exist with similar functionalities and configurations:** DRU and full-bridge VSC converters belong to this group. Full-bridge (FB) VSC converters are similar to half-bridge VSC in both configuration and functionality[35], hence a cost model will be built of FB VSC using HB VSC as reference base. Similarly, the cost of DRU will be based on the cost of a LCC converter station.
3. **Relatively new and unique products which are still under development:** Those products are not yet available in the market and there are very few or no commercial projects with such products, it is therefore not possible to establish the cost data through historical data. Furthermore, due to the unique feature of those products, it is also difficult to establish the cost model by evaluating the cost data of

[35] It is worth noting that a FB VSC is capable of block fault currents in case of a DC grid fault and the ability to operate at low or reversed voltages.

similar products. A “bottom-up” approach will be used to obtain the direct material cost. The other cost items will be estimated as additional percentages of the direct material cost. This applies mainly to DCCBs with different solutions.

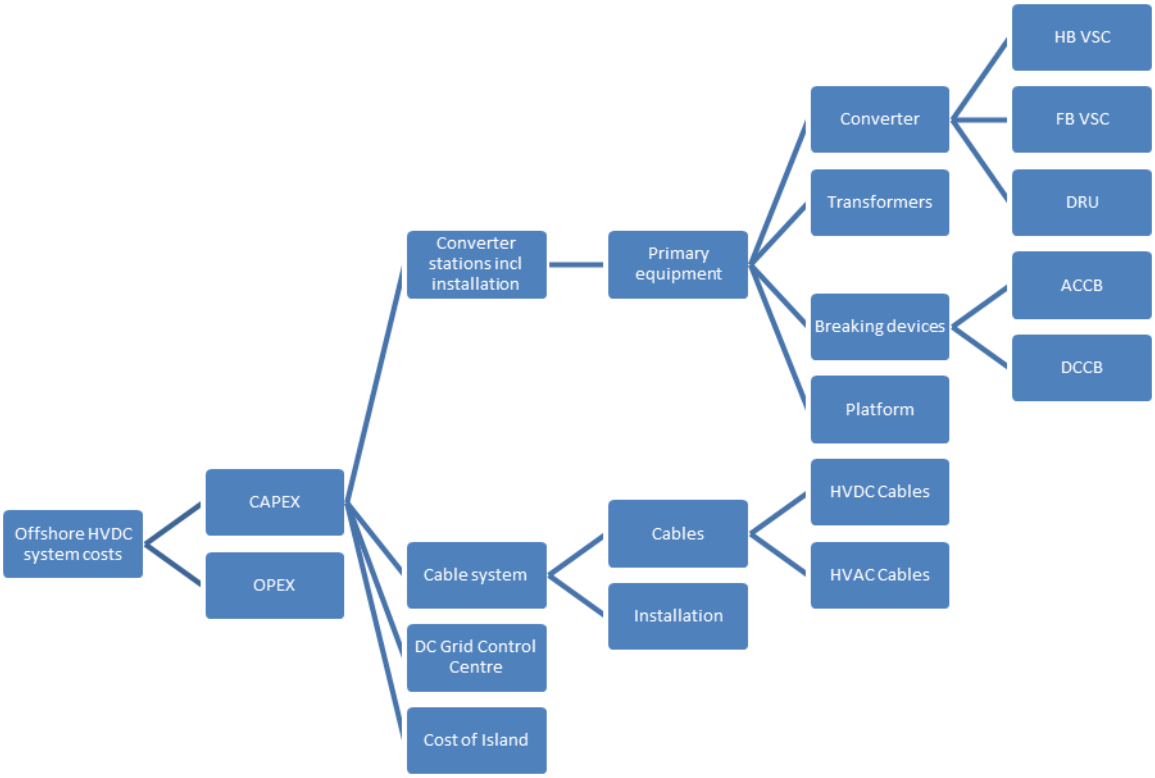


Figure 35 - Components that are taken into account in the cost data collection.

APPENDIX V

LEARNING CURVE EFFECT ON COST DEVELOPMENT

This Section describes the methodology for evaluating the impact of learning curve effect on the cost development of the grid components in the MOG. The methodology is largely identical to that of the E-Highway2050 project [60]. The intention is to give an indication on the development of cost development towards 2050.

This Section is organised as follows:

1. Firstly, the important cost drivers are listed and how such drivers will develop towards 2050.
2. This will be followed by the cost break down of the major component categories, such as converter stations, cables and DCCBs.
3. The results are then presented, i.e. the cost development of various categories of components.

PROCESS DESCRIPTION

An HVDC grid consists of various components, such as VSCs, DCCBs, cables and offshore platforms. For each component, the cost can be constructed by considering the following three levels of break downs:

1. Firstly, the total cost consists of a set of **cost elements** with different percentages, this is illustrated in Figure 36, where cost elements include the cost of equipment, installation and transportation, civil works, project management, right of ways, risk contingency and a profit margin.

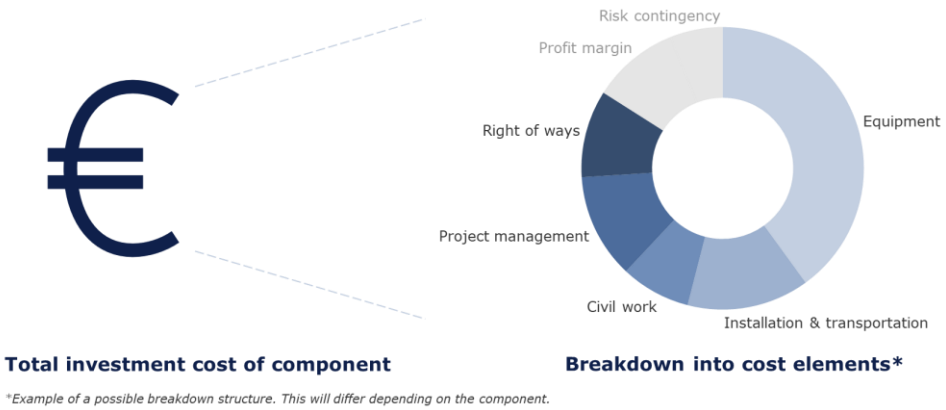


Figure 36 - Breakdown of total investment cost of components into cost elements

2. Secondly, the value of each cost element is further determined by a weighted sum of a set of **price drivers**, as shown in Figure 37. The price drivers include labour, engineering, energy and commodity/metal, which are further explained in Table 10.

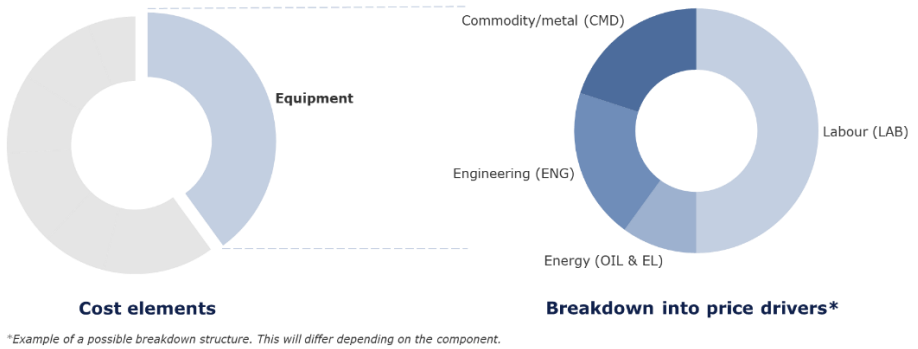


Figure 37 - Breakdown of the different cost elements into price drivers

Table 10 - Cost driver indexes used in the model.

COST DRIVER INDEXES	DESCRIPTION
Commodities	Commodities used in production (steel, aluminium, copper, power electronics)
Energy	The energy used in the installation and manufacturing of various components / subsystems.
Labour cost	Low-skill labour typically used for civil work and installation.
Engineering	High-skill labour typically used for project management and engineering.

3. In the end, the contribution of each price driver to any cost element will be determined by the development of unit price and quantity needed of the price driver within the individual cost element, this is illustrated in Figure 38 using the labour cost as an example.

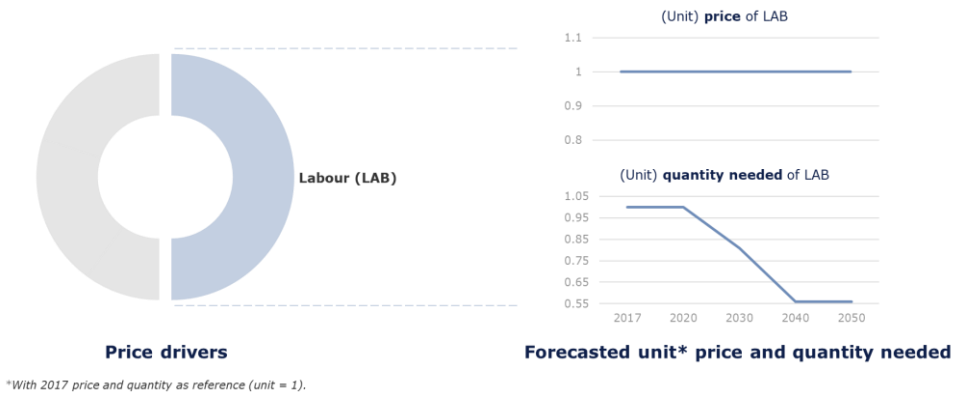


Figure 38 - Unit cost and quantity needed for price driver towards 2050. In the figure a trend is illustrated where the unit price of labour is constant and the quantity needed is decreased by 45% from 2020 to 2040.

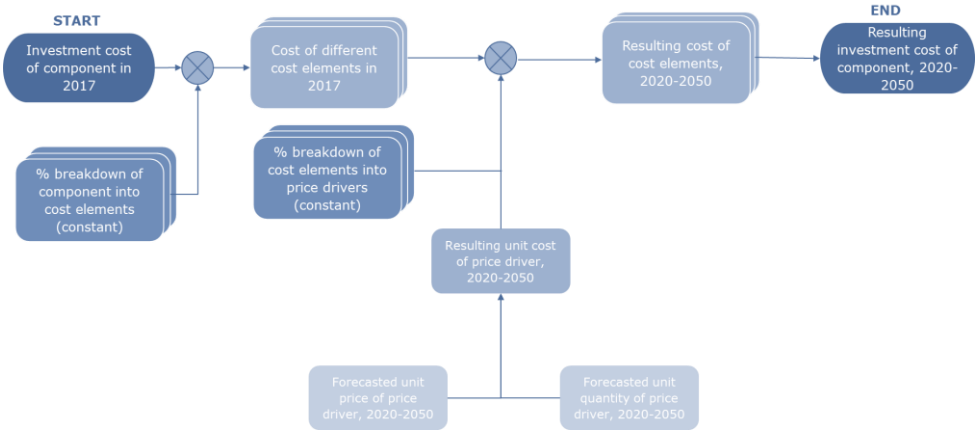


Figure 39 - The overall process flowchart for cost development of DC grid components.

In summary, the process of deriving the cost development of DC grid components is illustrated in the flowchart in Figure 39 and the equation below:

$$C_{cm}^{t} = \sum_{e \in \mathcal{E}} C_{cm,e}^{t} = \sum_{e \in \mathcal{E}} \left[C_{cm,e}^{2017} \times \sum_{i \in \mathcal{I}} \left(P^{t,i} \times Q_{cm,e}^{t,i} \times S_{cm,e}^{i} \right) \right]$$

Where:

- $\mathcal{C} = \{$Onshore and offshore VSC converters, Sea and Land cable, DCCB, Offshore HVDC platform$\}$ is the set of components to be considered.
- $\mathcal{T} = \{2017,\ 2018,\ \ldots,\ 2050\}$ is the set of years from 2017 to 2050
- $\mathcal{E} = \{$Equipment, Installation & transportation,Civil works, Project Management, etc$\}$ is the set of cost elements.
- $\mathcal{I} = \{$Labour, Oil&Energy, Engineering, Commodity$\}$ is the set of price driver indices.
- $cm \in \mathcal{C}$ and $t \in \mathcal{T}$
- C_{cm}^{t}: total investment cost of component cm in year t
- $C_{cm,e}^{t}$ and $C_{cm,e}^{2017}$: cost element e of component cm in year t and year 2017, respectively.
- $S_{cm,e}^{i}$: percentage share of price indice i for cost element e in compoent cm
- $P^{t,i}$: unit price of indice i in year t relative to the value in 2017
- $Q_{cm,e}^{t,i}$: quanity needed of price indice i for cost element e in compoent cm in year t, this is relative to 2017 value

DATA SOURCES AND ASSUMPTIONS:

When assuming the price development of the major price drivers, the following mega trends and assumptions were made:

- Artificial intelligence, robotics and other forms of automation will most likely advance at a rapid pace and will boost productivity. In this analysis it is assumed that the amount of labour- and engineering hours needed in production, installation, civil work and project management will decline in the next decades as a result of this.
- The numbers are based on a study performed by PWC[36], who have identified the automation potential within different industries and across different educational levels.
  - The study concludes that by late 2020, **automation potential** for **manufacturing jobs** requiring low education is 24% while the automation potential for manufacturing jobs requiring high education is 15%. By mid 2030s the numbers are increased to 60% and 19% respectively.
  - For the **construction sector** in late 2020s, **automation potential** for jobs requiring low education is 16% and automation potential for jobs requiring high education is 10%. By mid 2030s the numbers are increased to 48% and 12% respectively.

[36] Source: https://www.pwc.co.uk/services/economics-policy/insights/the-impact-of-automation-on-jobs.html

- **Cost of commodities:** Six commodities are identified that are relevant when discussing the price development of HVDC equipment: Aluminium, copper, steel, power electronics, XLPE and oil. World Bank provides price forecast for aluminium, copper, steel and oil towards 2030 and is used in this analysis [61]. For XLPE constant price are assumed as there is no price forecast. For power electronic units the price forecast is based on Electronics sourcing[37].
- **Cost of Energy:** Production of equipment, installation and transportation, as well as civil work require energy. The aim has been to reflect the change in energy mix and energy price. In the analysis it is assumed that electricity will replace a significant part of fossil fuel used in production of equipment and in civil work. For installation and transportation, it is assumed that fossil fuel will still be needed to transport and install the heavy equipment.
  - Based on the DNV GL's Energy Transition Outlook 2018 (ETO) [62], electricity consumption will more than double by mid-century to meet 45% of world energy demand. Have assumed constant increase towards 45% in 2050.
  - Price of electricity is based partly on NVE [63] and partly on DNV GL expert opinion.

RESULTS

The procedure mentioned above was applied to the major component categories and the results are summarized in Table 11 and Figure 40 using the 2017 cost level as reference values.

Table 11 - Cost development of major HVDC components.

PRICE CHANGE (%)	2017	2020	2030	2040	2050
Onshore converter station	0	1 %	-17 %	-29 %	-32 %
Offshore converter station	0	1 %	-16 %	-28 %	-31 %
Submarine cable	0	1 %	-3 %	-8 %	-13 %
Underground cable	0	1 %	-6 %	-13 %	-18 %
Offshore platform	0	4 %	-15 %	-26 %	-30 %
DCCB	0	1 %	-18 %	-31 %	-39 %

The results show that DCCBs will experience a steep drop in price, reflecting that the amount of R&D hours is currently high. Further on, both offshore and onshore VSC converter stations, as well as offshore platforms, are likely to experience a rapid decrease in price.

[37] Source: http://www.electronics-sourcing.com/2017/06/02/steady-prices-for-discrete-chip-tags/

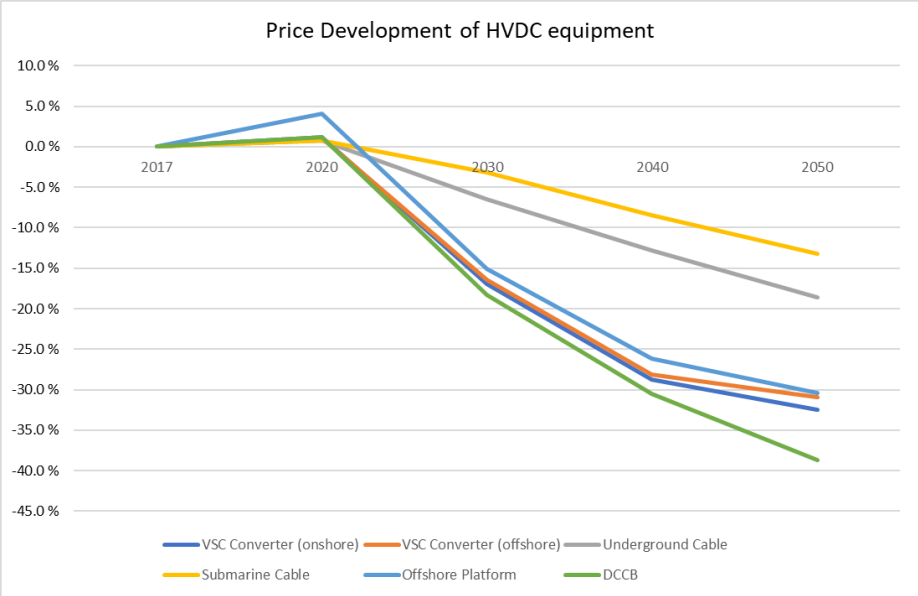


Figure 40 - Cost development of major HVDC components.

APPENDIX VI

COST CALCULATION RESULTS FOR THE CENTRAL WIND SCENARIO

A similar trend as in the High wind scenario can be found in the Central wind scenario when it comes to the comparison of the total costs, as is shown in Table 12. Again the HUB concept shows a decrease in total costs compared to BAU, although by 3 % under this scenario as opposed to 7 % in the High wind scenario. The relative increase in costs for the NAT and EUR concept is similar as in the High wind scenario, with 3 to 8 % cost increase respectively. The respective costs show that the influence of the artificial islands on the costs has decreased. This is partially because the number of islands have decreased (4 as opposed to 6) and also because each island on average replaces a lower number of platforms. The meshing in the NAT and EUR concept is of similar magnitude as in the High wind scenario, which means that the relative cost increase compared to BAU is also similar.

Table 12 - CAPEX and OPEX in bn€ throughout the analysed period for each of the concepts in the Central wind scenario. Note that these figures have a ±30 % uncertainty on cost data input.

		2025	2030	2035	2040	2045	2050	TOTAL
CAPEX	*BAU*	21.60	16.30	20.40	21.60	25.90	15.40	121.20
	NAT	23.60	17.60	21.60	21.10	24.40	17.00	125.30
	HUB	25.70	16.20	16.90	21.10	19.20	15.70	114.80
	EUR	23.40	20.40	21.80	21.70	24.70	18.00	130.00
OPEX	*BAU*	1.30	3.00	4.80	6.90	9.20	11.10	36.30
	NAT	1.40	3.30	5.20	7.30	9.60	11.50	38.30
	HUB	1.50	3.40	5.00	6.80	8.80	10.40	35.90
	EUR	1.40	3.50	5.50	7.60	9.90	11.90	39.70

		TOTAL
Cumulative Investment & Operational Costs	*BAU*	157.50
	NAT	163.60
	HUB	150.70
	EUR	169.70
Cumulative Investment & Operational Costs comparison	*BAU*	0%
	NAT	4%
	HUB	-4%
	EUR	8%

COST CALCULATION RESULTS FOR THE LOW WIND SCENARIO

The Low wind scenario breaks the trend that was seen in both the High and Central wind scenario, as the costs for all concepts are almost equal. Refer to Table 13. A very minor difference is found in the NAT and EUR concept as opposed to BAU, with the NAT concept having slightly lower costs and the EUR concept having slightly higher costs. In the NAT concept, there are only a few meshed structures and no dedicated protection system is required for any of these structures. As the reduction in total cable length is still significant compared to BAU, this leads to an overall cost decrease. In the EUR concept, where a dedicated protection system is necessary in a few meshed cases, the decrease in cable length is not high enough to offset these costs. The HUB concept only encompasses 3 islands, each of a capacity under 10 GW. As the topology generation also connects OWFs to the island that are between the island and shore, the total cable length in the HUB concept increases. This shows that replacing DC platforms with artificial islands reduces costs only when a larger number of platforms are replaced when connecting OWFs that are between shore and the island to offset the additional cost of cable. The tipping point for the decision of an island is dependent on the capacity of OWFs connected and the length of additional cable needed – if OWFs are located between the island and shore.

Table 13 - CAPEX and OPEX in bn€ throughout the analysed period for each of the concepts in the Low wind scenario. Note that these figures have a ±30 % uncertainty on cost data input.

		2025	2030	2035	2040	2045	2050	TOTAL
CAPEX	*BAU*	13.30	8.60	14.70	20.70	10.30	7.30	74.80
	NAT	13.30	8.80	14.10	19.60	10.60	7.80	74.10
	HUB	18.60	6.00	14.90	16.80	9.70	8.10	74.10
	EUR	13.50	9.80	14.40	19.30	10.80	7.20	75.10
OPEX	*BAU*	0.80	1.80	3.00	4.80	6.20	7.00	23.40
	NAT	0.80	1.80	3.00	4.70	6.10	6.90	23.20
	HUB	1.10	2.20	3.30	4.80	6.10	6.90	24.30
	EUR	0.80	1.90	3.10	4.80	6.20	7.00	23.80

		TOTAL
Cumulative Investment & Operational Costs	*BAU*	98.20
	NAT	97.30
	HUB	98.30
	EUR	98.90
Cumulative Investment & Operational Costs comparison	*BAU*	0%
	NAT	-1%
	HUB	0%
	EUR	1%

APPENDIX VII

BENEFIT CALCULATION RESULTS FOR THE CENTRAL WIND SCENARIO

In the following chapter, all the results of the benefit analysis of the Central scenario are presented.

B1: SOCIO-ECONOMIC WELFARE

The calculated marginal generation costs of the simulated countries show similar results between the four concepts in each scenario year. The reason for that are the same locations and installed capacities of the OWFs in each concept. Only the onshore connections and interconnectors differ and could therefore lead to differences in generation costs, but as the installed offshore generation capacity is significantly lower than in the High scenario, the differences are not as pronounced.

Table 14 - Marginal costs per fuel type in Central scenario

		2025	2030	2035	2040	2045	2050
Marginal costs [€/ MWh]	Biofuels	162.73	162.73	227.53	194.61	160.67	189.47
	Gas	64.15	86.05	68.85	51.66	34.47	17.27
	Hard Coal	59.46	86.45	71.21	55.97	40.73	25.49
	Hydro pump	3.00	3.00	3.00	3.00	3.00	3.00
	Hydro run	2.50	2.50	2.50	2.50	2.50	2.50
	Hydro turbine	6.00	6.00	6.00	6.00	6.00	6.00
	Lignite	54.59	78.54	63.01	47.48	31.95	16.41
	Nuclear	14.13	14.13	14.13	14.13	14.13	14.13
	Oil	68.08	92.39	76.62	60.86	45.10	29.33
	Other non-RES	77.29	101.24	85.71	70.17	54.64	39.11
	Other-RES	62.00	62.00	62.00	62.00	62.00	62.00
	RES (Solar & Wind)	0.00	0.00	0.00	0.00	0.00	0.00

The generation costs of the Central scenario are also quite similar to the High scenario until the year 2040 (Figure 41 and Figure 42). Afterwards, the costs of the four concepts in the Central scenario are significant lower because of the different marginal costs of fossil fuels compared to the High scenario. A comparison of the three scenarios with each other is therefore not recommended.

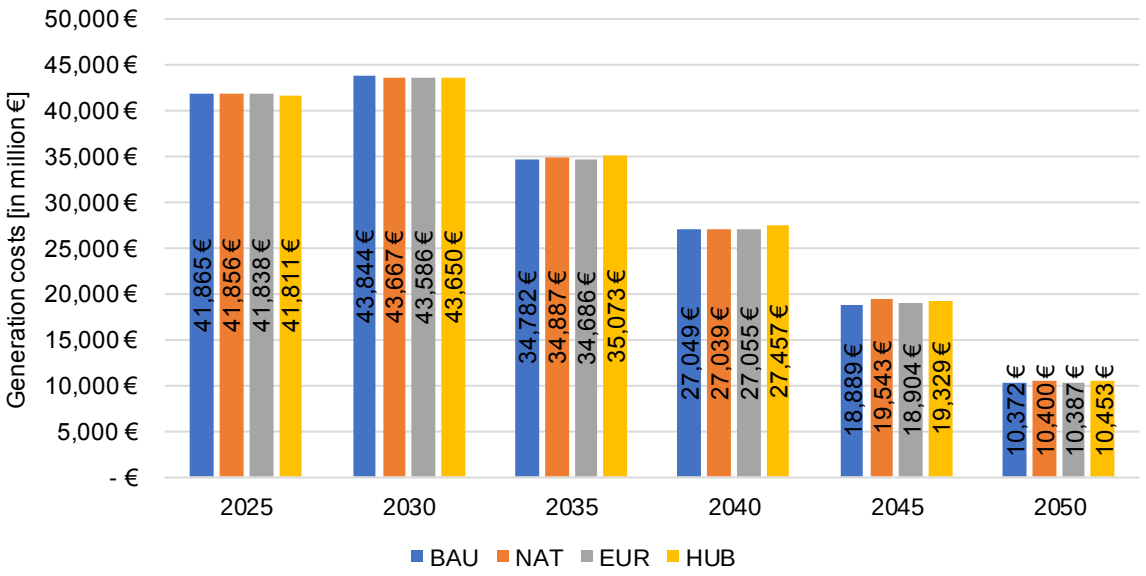


Figure 41 -Marginal generation costs of all North Seas countries per scenario year and concept for the Central scenario.

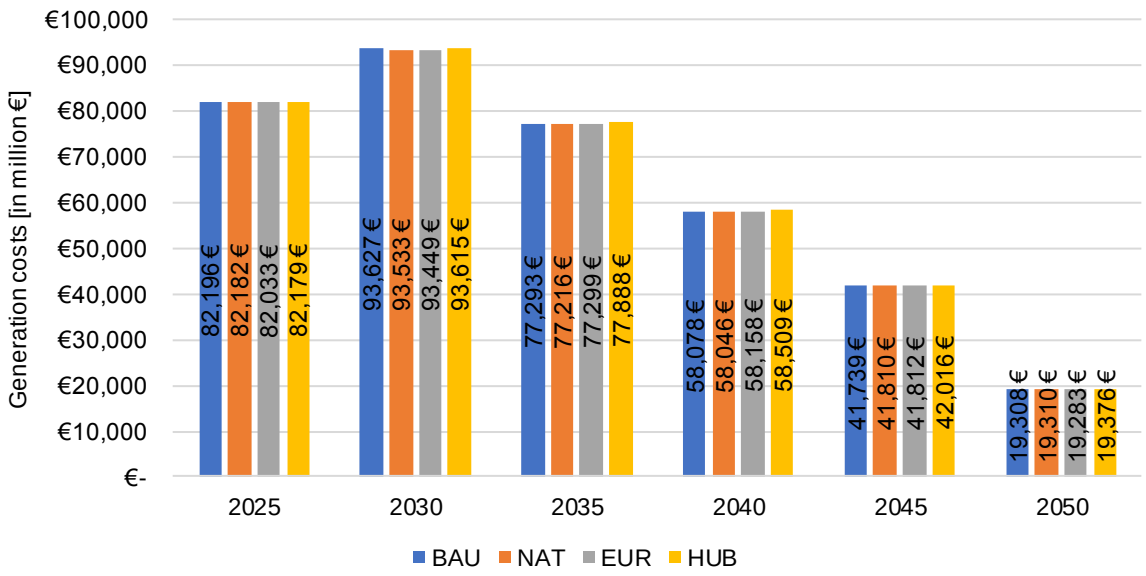


Figure 42 - Marginal generation costs of all simulated countries per scenario year and concept for the Central scenario.

The final socio-economic welfare is the depiction of how much better the NAT, EUR and HUB concepts fare against the BAU concept over the whole period under consideration in summed up marginal generation costs. As the generation costs are similar between the concepts, the socio-economic welfares are quite low (Table 15). The EUR concept has the highest benefit with savings of about 1.03 billion Euros over the 25-year period, followed by the NAT concept with 0.71 billion Euros. The HUB concept on the other hand has a negative socio-economic welfare and therefore higher generation costs than the BAU concept.

Table 15 - Socio-economic welfare of the simulated concepts in the Central scenario.

CONCEPT	SOCIO-ECONOMIC WELFARE
NAT	0.71 billion €

HUB	-6.72 billion €
EUR	1.03 billion €

B2: RES INTEGRATION

The KPI of the RES integration depicts the amount of curtailed energy from renewable generation for each concept. The curtailed generation types in the benefit simulation could be solar-thermal, solar-PV, wind-onshore and wind-offshore. Main reasons for curtailment of renewables are a higher generation potential than available load in combination with congestion on interconnectors between markets. Bottlenecks in the offshore topologies are not a reason for curtailment, as the whole offshore system is designed congestion-free.

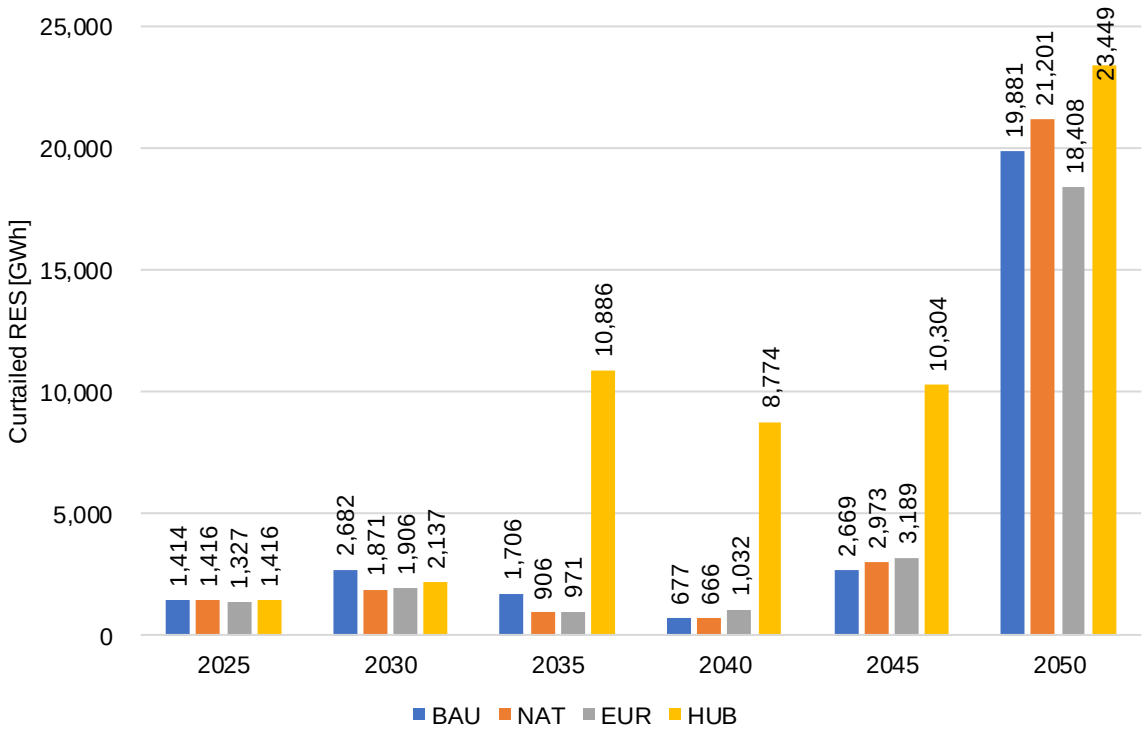


Figure 11-1: Curtailed generation of renewables of all North Seas countries per scenario year and concept for the Central scenario

The benefit analysis shows a high amount of curtailment in the HUB concept from 2035 onwards compared to the other three concepts. A further analysis shows high curtailment on German OWFs, which are connected to the German hub. The main connection onshore from this hub is through a potential Danish OWF to Denmark West, only lower capacity connections go directly to Germany. As Denmark does not have the corresponding load for that amount of generation and the NTCs on interconnectors to other markets are not sufficient enough for further transporting the offshore energy to western Europe, the OWFs have to be curtailed.

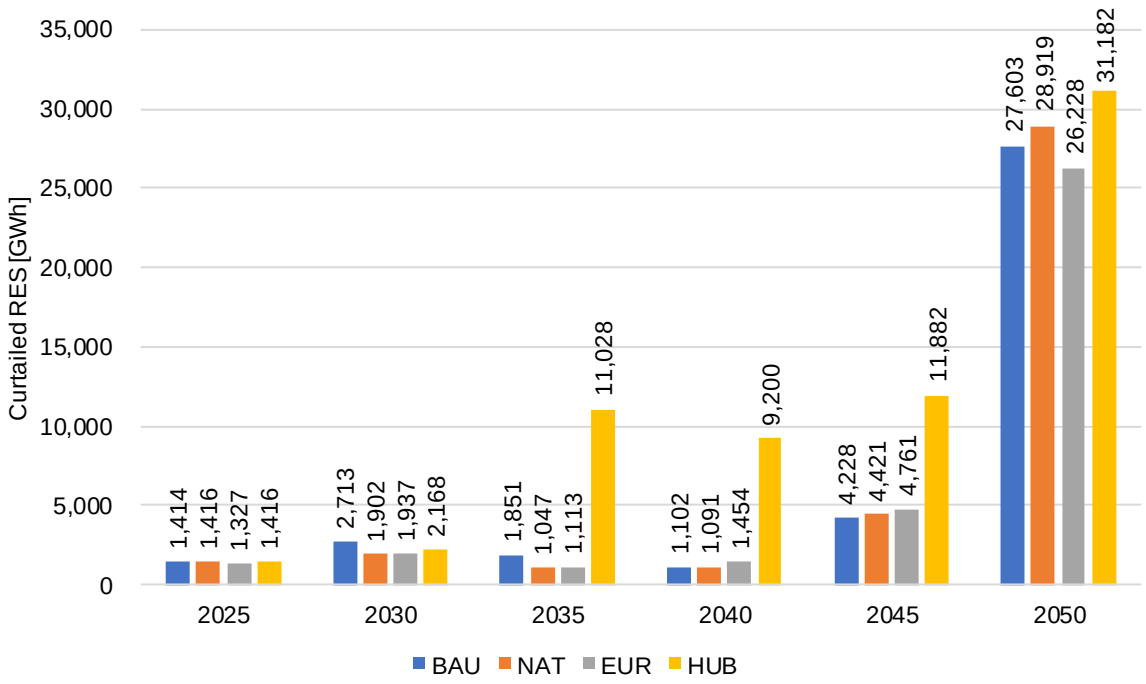


Figure 11-2: Curtailed generation of renewables of all simulated countries per scenario year and concept for the Central scenario

B3: CO_2 VARIATION

The KPI of the CO_2 variation depicts the CO_2 emissions per concept in the specific scenario year. Figure 11-3 shows the yearly emissions of all countries neighbouring the North Seas, whereas Figure 11-4 shows the yearly emissions of all simulated countries. High proportions of renewables in the system lead to a high decrease of CO2 emissions in 2030 and 2035 compared to the year 2025. New values of the marginal costs per fuel type in 2040 lead to a switch on the supply curve and make a deployment of fossil fuel (gas, hard coal and oil) cheaper than greener alternatives used before, which results in an increase in CO_2 emissions in 2040 and 2045. Only the high share of renewables in 2050 will lead to a significant reduction in emissions below the level of 2035.

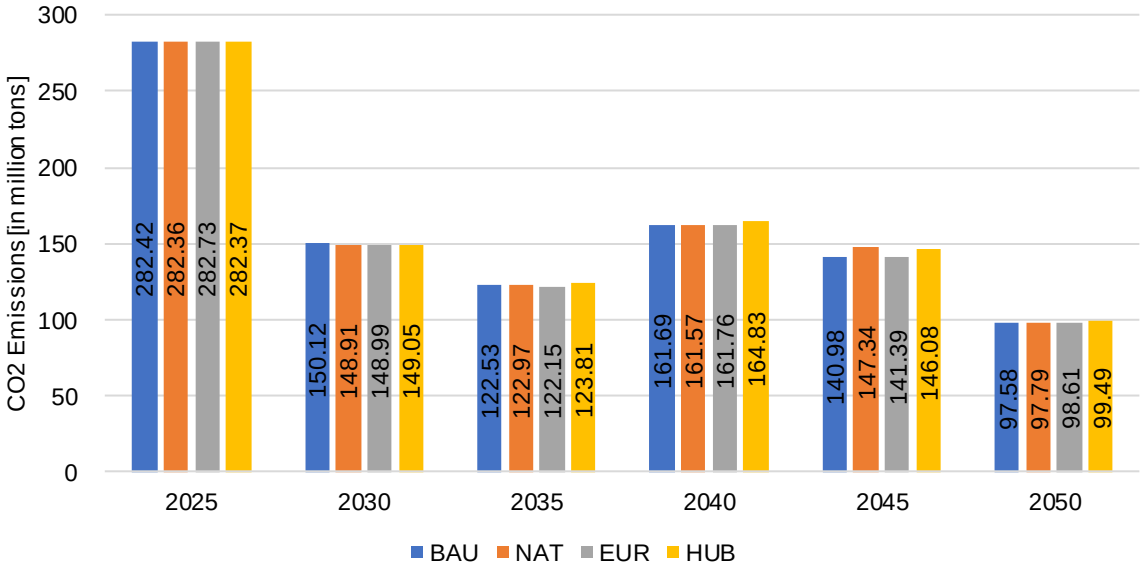


Figure 11-3: CO2 emissions of all North Seas countries per scenario year and concept for the Central scenario.

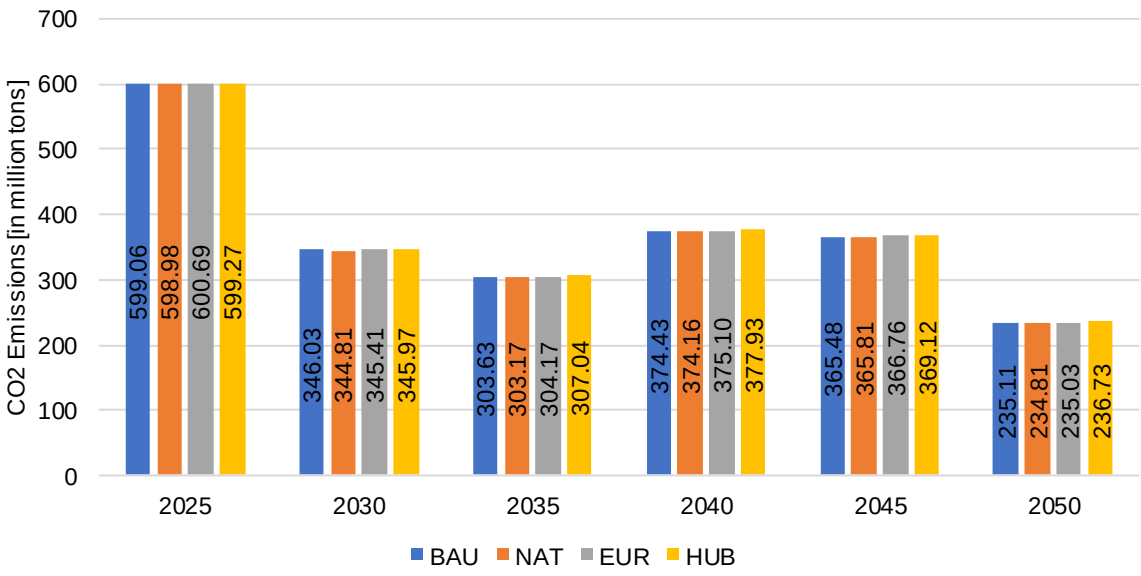


Figure 11-4: CO2 emissions of all simulated countries per scenario year and concept for the Central scenario.

B5: GRID LOSSES

The comparison of the losses is an analysis of the estimated system losses in the offshore system. As the onshore system is modelled with ideal components in the operational simulation, only losses of converters, cables and offshore transformers of the offshore topologies are being taken into account. The problem with this method is that a comparison of the four concepts with each other is not possible. The BAU concept uses the shortest distance to shore for evacuating the generated energy. The exchange with other bidding zones is then coordinated from the onshore bidding zone node and can happen via offshore or onshore interconnections, the latter option being without losses. This results in incomparable losses because in the BAU concept the energy exchange could happen on lossless onshore interconnections, e.g. between Germany and Denmark West, whereas in the EUR concept the offshore connection from the German OWF to the Danish shore is being used and losses occur. These discrepancies show that a comparison makes only sense within a concept and not between the different developed concepts. Furthermore, Deliverable 7.11 advises to neglect the difference in grid losses in the practical CBA.

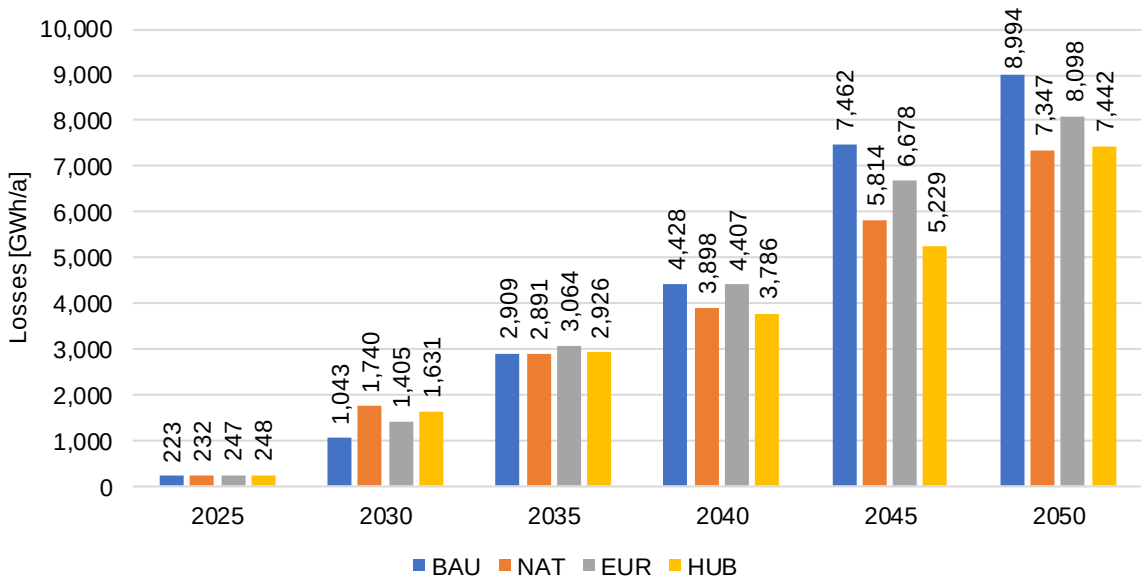


Figure 11-5: Grid losses of the offshore system per scenario year and concept in the Central scenario

B6: SECURITY OF SUPPLY – ADEQUACY: LOSS OF LOAD EXPECTATION

The operational dispatch simulation can determine hours of the simulated years, in which not sufficient generation potential and NTCs are available to cover the existing load in each market area. The missing energy difference is defined as *Loss of Load Expectation* (LOLE). The amount depends on the generation input data for the future generation park, available NTC between market areas and the offshore topology. As the used input data is taken from the ENTSO-E TYNDP 2018, already insufficient generation is transferred to this operational simulation. The developed offshore topology implemented into the European node model can however improve the available insufficient supply with additional interconnection capacity.

The only country which has LOLE is Finland in 2030 and that value already exists within the TYNDP 2018 data. Otherwise, a sufficiently high generation capacity is available in the entire simulated system.

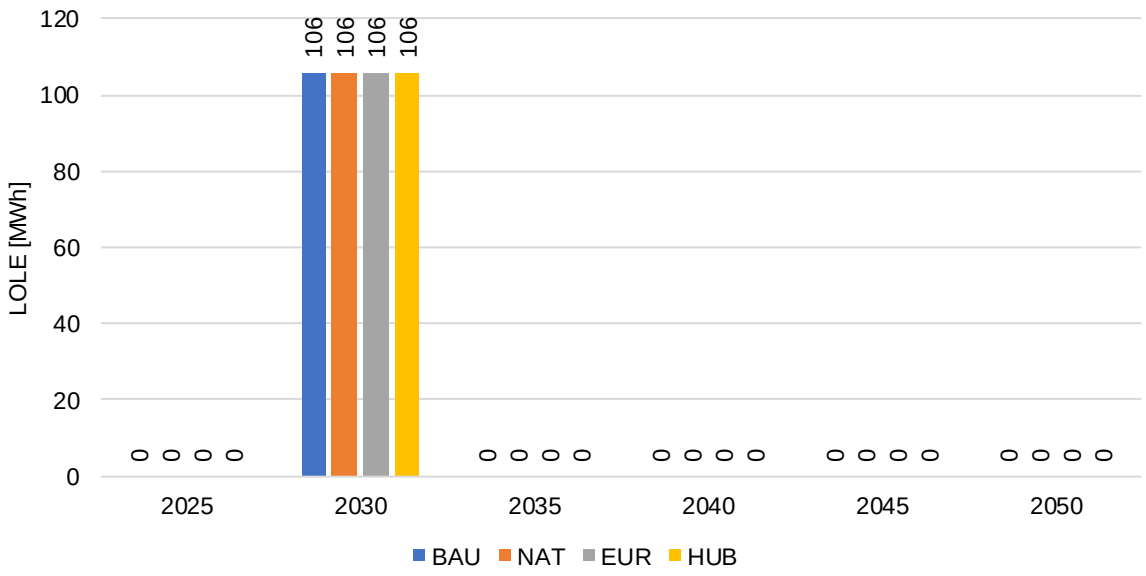


Figure 11-6: LOLE of all simulated Seas countries per scenario year and concept in the Central scenario

BENEFIT CALCULATION RESULTS FOR THE LOW WIND SCENARIO

In the following chapter, all the results of the benefit analysis of the Low scenario are presented.

B1: SOCIO-ECONOMIC WELFARE

The calculated marginal generation costs of the simulated countries show similar results between the four concepts in each scenario year. The reason for that are the same locations and installed capacities of the OWFs in each concept. Only the onshore connections and interconnectors differ and could therefore lead to differences in generation costs, but as the installed offshore generation capacity is significantly lower than in the High scenario, the differences are not as pronounced.

Table 11-1: Marginal costs per fuel type in Low scenario

		2025	2030	2035	2040	2045	2050
Marginal costs [€/ MWh]	Biofuels	162.73	162.73	227.53	194.61	160.67	189.47
	Gas	64.15	73.91	82.32	90.73	99.14	107.55
	Hard Coal	59.46	61.21	72.64	84.07	95.49	106.92
	Hydro pump	3.00	3.00	3.00	3.00	3.00	3.00
	Hydro run	2.50	2.50	2.50	2.50	2.50	2.50
	Hydro turbine	6.00	6.00	6.00	6.00	6.00	6.00
	Lignite	54.59	51.43	63.29	75.14	87.00	98.86
	Nuclear	14.13	14.13	14.13	14.13	14.13	14.13
	Oil	68.08	64.87	76.91	88.94	100.97	113.01
	Other non-RES	77.29	74.13	85.98	97.84	109.70	121.55
	Other-RES	62.00	62.00	62.00	62.00	62.00	62.00
	RES (Solar & Wind)	0.00	0.00	0.00	0.00	0.00	0.00

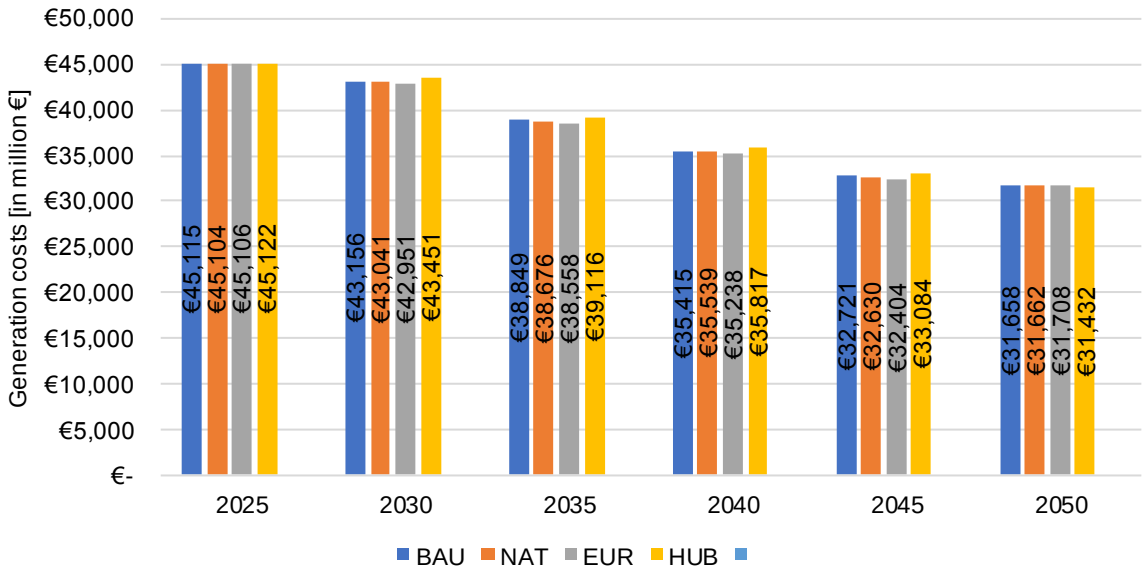


Figure 11-7: Marginal generation costs of all North Seas countries per scenario year and concept for the Low scenario

The marginal generation costs of the North Seas countries (Figure 11-7) in the Low scenario show a steady decline from 2025 to 2050, but not in the same high percentage as in High scenario, which has a generation cost decrease of more than 50 % over the same period.

However, when looking at the marginal generation costs for all simulated countries (Figure 11-8), an increase of costs occurs in 2045 and 2050 compared to the previous scenario year. The final generation costs in 2050 are above the level of 2030. The reason for that is the higher deployment of generation units with biofuels, gas and the unspecified fuel type “othernon-RES”. Their marginal costs are the highest of all fuel types and together with the lower share of nuclear, hard coal and lignite generation result in increasing generation costs.

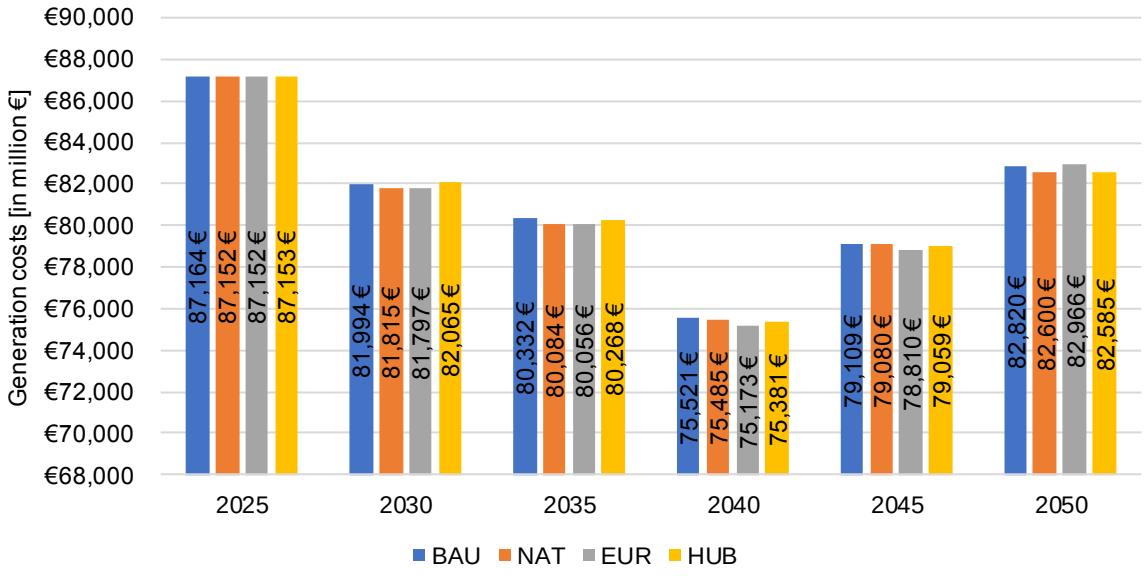


Figure 11-8: Marginal generation costs of all simulated countries per scenario year and concept for the Low scenario

The final socio-economic welfare is the depiction of how much better the NAT, EUR and HUB concepts fare against the BAU concept over the whole period under consideration in summed up marginal generation costs. As the generation costs are similar between the concepts, the socio-economic welfares are not that high over the

whole 25-year period (Table 11-2). The EUR concept has the highest benefit with savings of about 4.93 billion Euros over the 25-year period, followed by the NAT concept with 3.62 billion Euros and the HUB concept with 2.14 billion Euros.

Table 11-2: Socio-economic welfare of the simulated concepts in the Low scenario

CONCEPT	SOCIO-ECONOMIC WELFARE
NAT	3.62 billion €
HUB	2.14 billion €
EUR	4.93 billion €

B2: RES INTEGRATION

The KPI of the RES integration depicts the amount of curtailed energy from renewable generation for each concept. The curtailed generation types in the benefit simulation could be solar-thermal, solar-PV, wind-onshore and wind-offshore. Main reasons for curtailment of renewables are a higher generation potential than available load in combination with congestion on interconnectors between markets. Bottlenecks in the offshore topologies are not a reason for curtailment, as the whole offshore system is designed congestion-free.

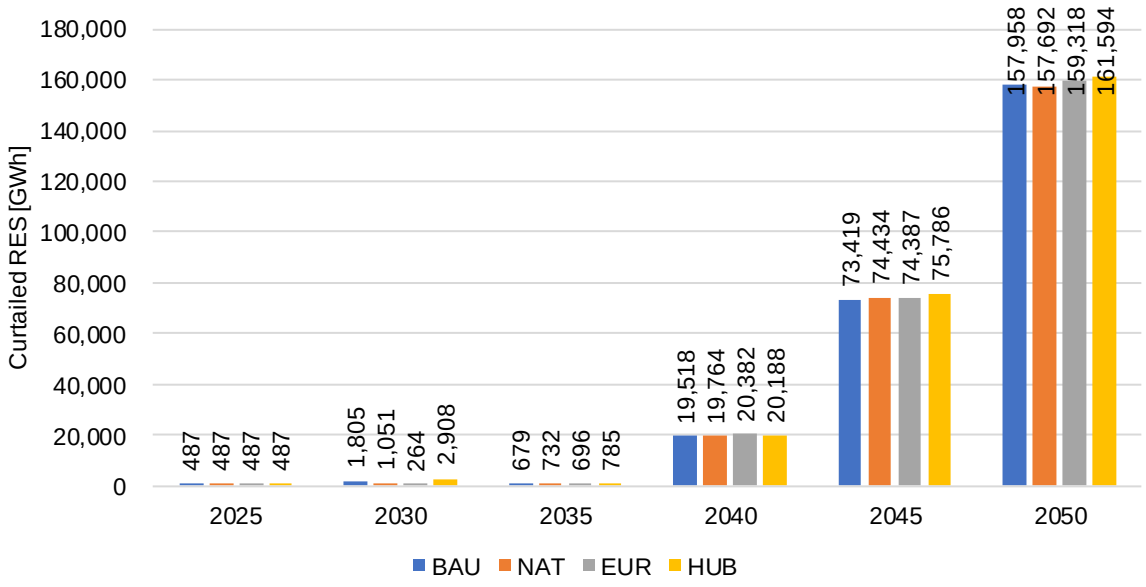


Figure 11-9: Curtailed generation of renewables of all North Seas countries per scenario year and concept for the Low scenario

The benefit analysis shows a high amount of curtailment in all four concepts from 2035 onwards. A further analysis shows especially high curtailment of PV generation, which corresponds with the scenario background. The foundation of the Low scenario is the *Distributed Generation* scenario of the TYNDP 2018 which, as the name suggests, has a higher generation capacity of PV installed than the other scenarios. This results in a surplus supply of renewable energy during times of high solar radiation and therefore curtailment. This behaviour could be avoided by integrating storage options into the benefit simulation. The same has already been discussed in 7.3.4 with the high installed wind generation capacity.

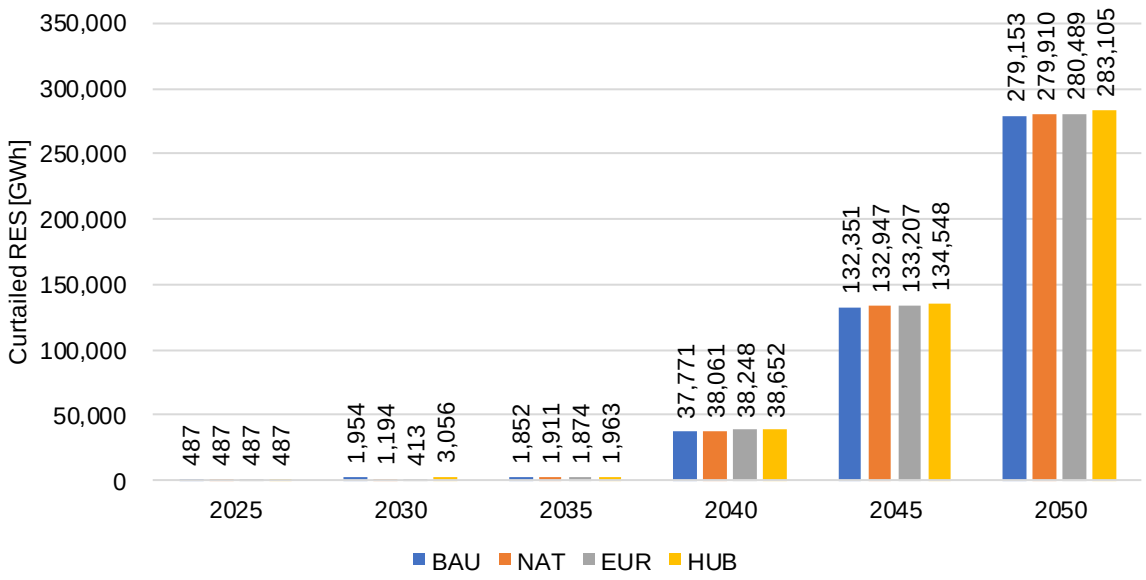


Figure 11-10: Curtailed generation of renewables of all simulated countries per scenario year and concept for the Low scenario

B3: CO_2 VARIATION

The KPI of the CO_2 variation depicts the CO_2 emissions per concept in the specific scenario year. Figure 11-11 shows the yearly emissions of all countries neighbouring the North Seas, whereas Figure 11-12 shows the yearly emissions of all simulated countries. An increasing share of renewables in the system result in a steady decline of CO2 emissions until 2050 compared to the year 2025. As the developed offshore system in the North Seas is relatively small compared to the other scenarios and the installed generation capacity onshore, differences between the concepts are almost not existent regarding the CO_2 emissions.

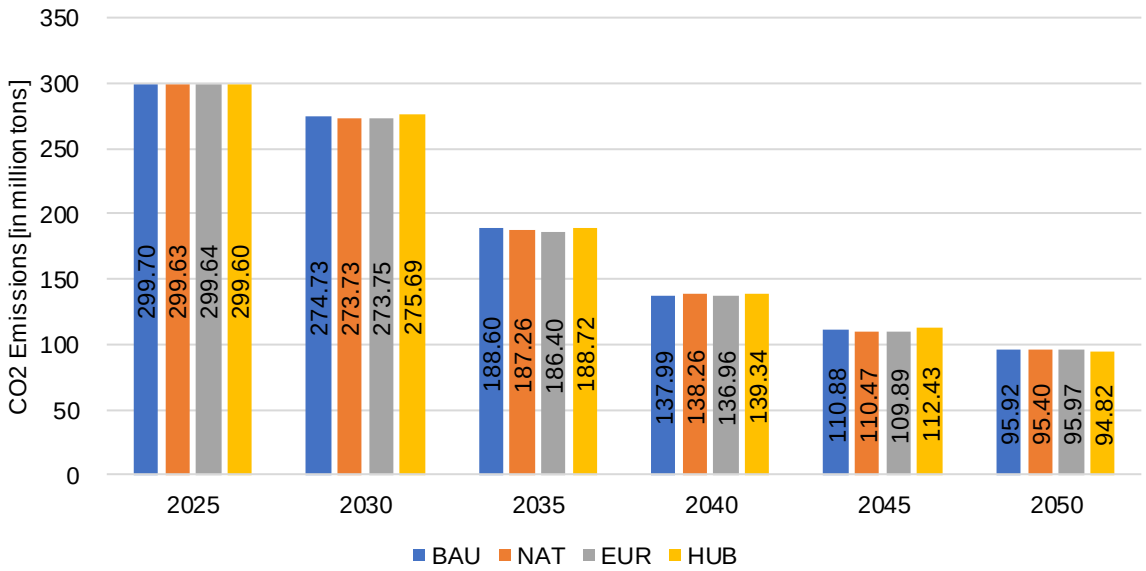


Figure 11-11: CO2 emissions of all North Seas countries per scenario year and concept for the Low scenario

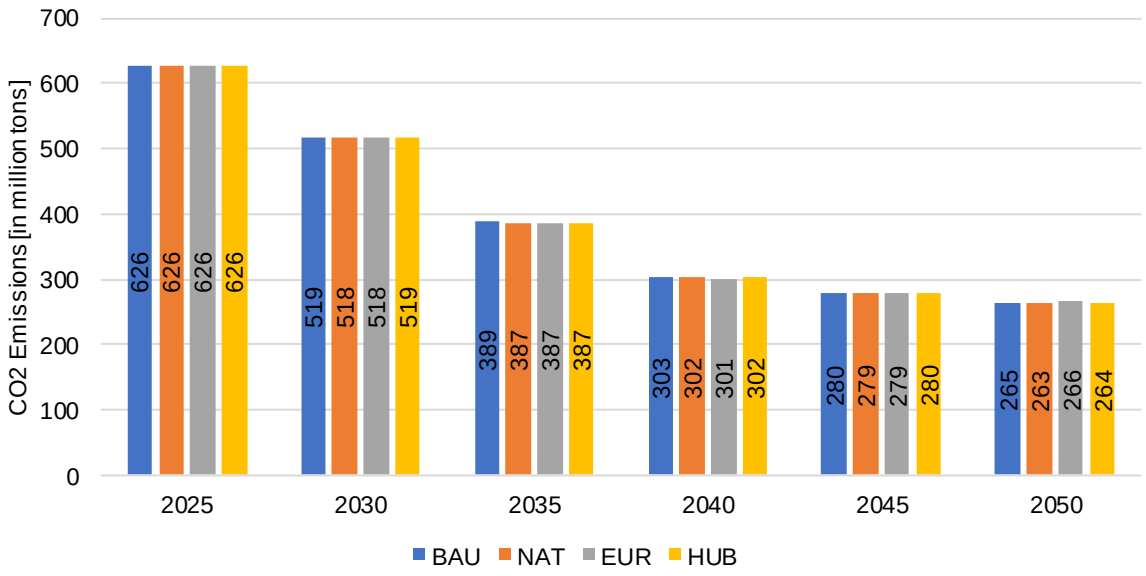


Figure 11-12: CO2 emissions of all simulated countries per scenario year and concept for the Low scenario

B5: GRID LOSSES

The comparison of the losses is an analysis of the estimated system losses in the offshore system. As the onshore system is modelled with ideal components in the operational simulation, only losses of converters, cables and offshore transformers of the offshore topologies are being taken into account. The problem with this method is that a comparison of the four concepts with each other is not possible. The BAU concept uses the shortest distance to shore for evacuating the generated energy. The exchange with other bidding zones is then coordinated from the onshore bidding zone node and can happen via offshore or onshore interconnections, the latter option being without losses. This results in incomparable losses because in the BAU concept the energy exchange could happen on lossless onshore interconnections, e.g. between Germany and Denmark West, whereas in the EUR concept the offshore connection from the German OWF to the Danish shore is being used and losses occur. These discrepancies show that a comparison makes only sense within a concept and not between the different developed concepts. Furthermore, Deliverable 7.11 advises to neglect the difference in grid losses in the practical CBA.

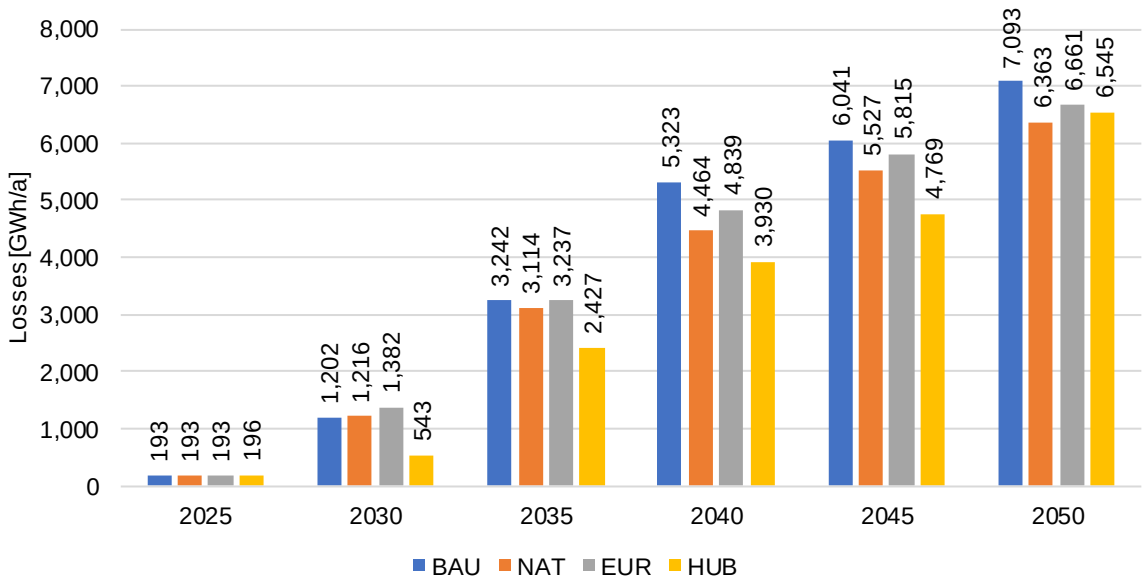


Figure 11-13: Grid losses of the offshore system per scenario year and concept in the Low scenario

B6: SECURITY OF SUPPLY – ADEQUACY: LOSS OF LOAD EXPECTATION

The operational dispatch simulation can determine hours of the simulated years, in which not sufficient generation potential and NTCs are available to cover the existing load in each market area. The missing energy difference is defined as *Loss of Load Expectation* (LOLE). The amount depends on the generation input data for the future generation park, available NTC between market areas and the offshore topology. As the used input data is taken from the ENTSO-E TYNDP 2018, already insufficient generation is transferred to this operational simulation. The developed offshore topology implemented into the European node model can however improve the available insufficient supply with additional interconnection capacity.

The only country with LOLE in all four concepts before 2045 is Finland. That value already exists within the TYNDP 2018 data. Irelands does also have an hour in 2030 where a 22.1 MWh demand cannot be covered by generation or trading. The high values for LOLE in 2050 are directly correlated with the high numbers of curtailment in this scenario. More than half of the bidding zones involved in the simulation have at least one hour of LOLE in 2050, with almost all the lost load occurring in Hungary and Czech Republic. Modelling storage options could help to store and dispatch the PV generated energy during these hours.

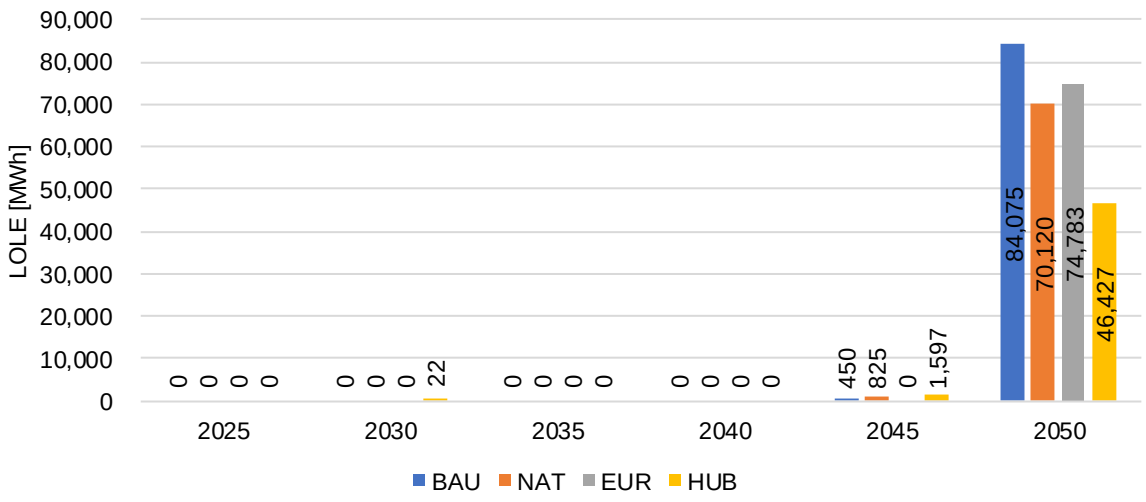


Figure 11-14: LOLE of all North Seas countries per scenario year and concept in the Low scenario

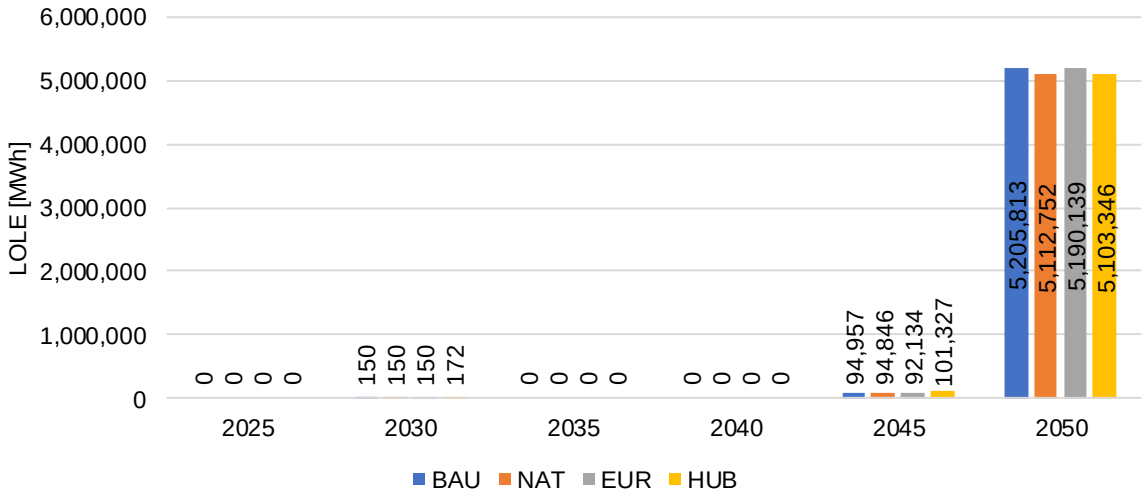


Figure 11-15: LOLE of all simulated countries per scenario year and concept in the Low scenario

APPENDIX VIII

Study performed by TenneT TSO B.IV.

OVERVIEW OF BENEFITS

The following Section completes the qualitative benefit assessment. It was carried out as a separate research into the benefits of MOGs and thus is used as a reference to the qualitative benefits. Where necessary for the storyline, parts of this research have been incorporated in the quantitative benefit discussion.

B1: SOCIO-ECONOMIC WELFARE

A MOG would potentially provide a large amount of interconnection capacity, connecting different European countries using power links with vastly higher capacities than available today. This will result in price convergence (through market coupling). This price convergence results in a direct effect on socio-economic welfare, which consists of the sum of consumer surplus, producer surplus, and – in the case of limited interconnection capacity – congestion rent. This is illustrated by Figure 43 below. The allocation of this socio-economic welfare to either consumers or producers is not relevant for the evaluation of total benefits, but could of course impact social acceptance or political support. The welfare gain of a project is then the socio-economic welfare, minus the cost of items considered in the CBA. This means that although any additional interconnection increases socio-economic welfare, the marginal gains of every additional interconnector may decrease. This could result in additional interconnector capacity not being worth the construction and/or operation costs (diminishing returns).

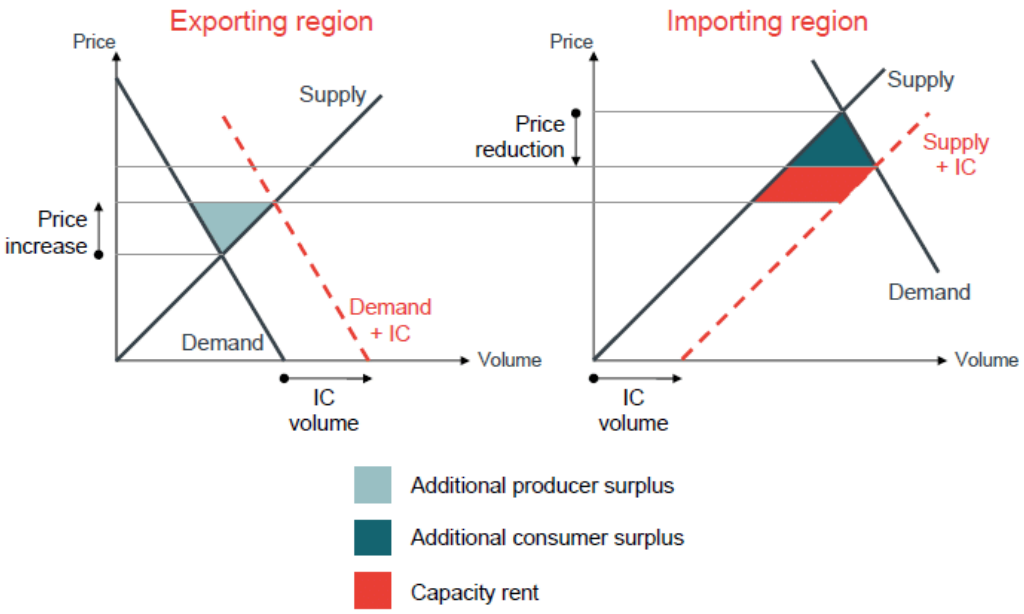


Figure 43 - Illustrative example of increase in socio-economic welfare due to an increase interconnection capacity, resulting in a producer surplus, consumer surplus and congestion (capacity) rent [35].

The concept of diminishing returns could be applicable in the development of an offshore grid: the optimal amount of interconnection capacity for socio-economic welfare may be different than the optimal amount of interconnection capacity for other benefits, such as renewable energy sources integration. In principle, these would lead to similar outcomes if the electricity market would function perfectly and all externalities (i.e. global warming due to CO_2-emissions) would be included within the market. However, the existing electricity market

although it internalises many costs (such as emission, pollution security of supply, etc.), does not represent a perfect market since it does not include all of the externalities [36]. Therefore, other benefits than socio-economic welfare can be considered to be relevant to the development of an offshore grid as well.

The increase in market coupling due to an increase in interconnection would also reduce the quantity volatility in the market due to a larger volume of the market. This increase in interconnection will increase predictability of the market for the wind developers and therefore decrease their risk. Although some aspects of this benefit are included in the direct socio-economic welfare calculations, the decrease in risk uncertainty due to a larger market can be considered to be a separate benefit. Decreasing risks has two major effects: wind farm developers can apply a smaller risk margin in the design of their business case and these developers can attract large amounts of capital at lower interest rates due to the lower uncertainty of the project. As a result, subsidy schemes become cheaper or superfluous and wind farm development is stimulated due to a decrease in barriers to development.

Furthermore, the electricity market considered actually consists of different markets. The aforementioned benefits apply to the commodity trading of electricity (all timescales). However, there is also a market for balancing services provided to the TSO. Due to an increasing share of variable renewable energy sources, balancing might become even more important in the future. Balancing of supply and demand can be achieved by increasing or decreasing the local supply and demand of electricity within one region (bidding zone), but also through increasing or decreasing the amount of energy transferred over interconnectors with other countries. Increasing the capacity of interconnection will result in more efficient international access to different suppliers of balancing services. This will result in a cost decrease for the relevant TSOs, which ultimately impact end-consumer transmission charges. As a result, prices between different bidding zones may converge generally and shorter or even real-time pricing may become more relevant.

Moreover, a MOG could result in less congestion management, which would result in lower redispatch costs. Congestion management is necessary if there are technical constraints to the desired flows resulting from the electricity market. Within one bidding zone ('market'), it is assumed that the grid is perfect ('copper plate') while matching demand and supply curves. This is, however, not always the reality. The transmission grid has technical constraints and the market optimisation does not take the geographical dimension of such grid constraints into consideration. If this leads to problematic situations, the TSO will require power generation to move from one area to another area within the same bidding zone. These 'redispatch' procedures come at high costs, since the original power supplier needs to be compensated for not being able to deliver power and another power supplier needs to be compensated for being required to deliver power. Preventing redispatch can thus save costs. If a grid is more interconnected, it resembles a copper plate more closely, resulting in less congestion management necessary and thus lower redispatch costs. This benefit is however strongly dependent on future bidding zone configurations.

B2: RENEWABLE ENERGY SOURCES INTEGRATION

A MOG could enable the enhanced integration of renewable energy sources into the power system.

A first benefit with regards to the integration of RES is the provisioning of alternative pathing for wind evacuation. Even without applying a strict N-1 security criterion, a MOG would provide some redundancy for wind evacuation. As the availability of the offshore grid is not perfect, there is a significant benefit to having an alternative path for wind electricity available. This increases the amount of renewable energy integrated into the system, but also save costs in compensation for downtime of the grid. The three-year (2015-2017) average offshore grid availability of TenneT was 94,21% compared to an onshore availability of 99,9987% [37]. This difference is due to

the current absence of any redundancy in the offshore grid. Having a MOG could increase the redundancy and thus the net availability of the offshore grid. Although this benefit alone may not be sizeable enough to justify the development of a MOG, it could still be a significant potential benefit to the development of the grid.

A second benefit with regards to the integration of RES is the improved access to storage due to more interconnection capacity. With an increasing share of variable renewable energy sources in the power system, the need for storage will most likely increase in the future. Storage can help balancing the variable production of renewable energy and help match this supply with consumer demand. As a MOG would increase the amount of available interconnection capacity, there will be improved access to storage. For example, the Netherlands already makes use of (virtual) storage of renewable energy by means of the NorNed interconnector to Norway [38]. This enables the Norwegian hydro power plants to act as a (virtual) storage for Dutch (wind) production. An increase in interconnector capacity would enable improved access to such storage facilities. This is valid regardless of the type of storage technology being used: more interconnection capacity would facilitate improved access and use of the storage facility in any case. This thus forms a second benefit of a MOG with respect to the integration of renewable energy sources.

Furthermore, a MOG could lead to more efficient use of wind production facilities as the curtailment of wind production could be decreased. Curtailment of (offshore) wind infeed is necessary when the grid is not capable of transporting all the intended electricity production to the load centres. For example, in 2016, 4.4% of German wind energy production was curtailed [39]. In Germany, offshore wind production is located in the Northern most part of the country whereas the Southern part represents the most important load centre. The transmission grid is not at all times capable of transmitting all wind power infeed from the North to the South. This results in the need for redispatch and curtailment: wind infeed is limited (curtailed) while conventional generation units in the south start producing electricity (redispatch). This results in alleviation of the grid constraints, but also in high redispatch costs and increased CO_2-emissions. A MOG could result in a decrease of curtailment and redispatch by having an overall higher capacity available. Assuming a slight overdesign in the offshore grid, offshore wind production could be exported directly to other countries in such a case, disburdening the onshore grid. This would lead to a more efficient use of wind production facilities as curtailment would not be necessary anymore. This results in lower costs, higher CO_2-emissions savings and a better business case for offshore wind farms, resulting in better incentives for offshore wind developments. As the rejection of power (curtailment) also leads to disturbances in the power quality, a decrease in curtailment would further improve the power quality offered in the system.

Fourthly, large amounts of wind power generation with strong reciprocal correlation can lead to marginal wind prices approaching 0 €/ MWh. This is due to the fact that wind power generation has low marginal costs, and at times of peak production a lot of wind power will suddenly become available. Of course, a marginal wind price approaching 0 €/ MWh is harmful for wind farm developers since it endangers their profit margins. A MOG would increase demand opportunity by having a larger market available for the accommodation of the wind power without having very strong reciprocal correlation between the wind parks. This is a contrast with the current – national – approach where the power generation of wind parks is usually quite strongly correlated. The improvement in demand opportunity would thus lead to less moments in time where the marginal wind infeed price approaches 0 €/ MWh. This both leads to better profit margins – a incentive for wind farm development – as well as to lower risks associated with wind farm development. Both effects would stimulate the integration of larger amounts of renewable energy sources into the power system.

Finally, a meshed gird could result in lower connection costs of offshore wind farms. The MOG would enable a more coordinated approach to grid development and wind park connection, resulting in lower costs than a

business as usual approach. This coordination refers to an international approach to spatial planning, assuming that countries collectively decide on what is built where and when (both wind evacuation and interconnection capacity), including an optimisation on total system costs, synchronised timing of construction and proper incentives in place [40]. The cost-reduction potential is also a key argument used for the advancement of the North Sea Wind Power Hub: the development of such a hub would result in significantly lower grid connection costs than connecting each wind park individually to shore [41].

However, the cost-reduction potential depends heavily on the assumptions used, most importantly with respect to the dimensioning of the grid. If one assumes an equal amount of wind evacuation capacity and interconnector capacity for each different topology, a MOG topology in which wind evacuation transmission assets are combined with interconnection use will be cheaper than a pure radial solution with separate point-to-point interconnectors. This difference in costs is due to less transmission assets required, as illustrated in Figure 44 below.

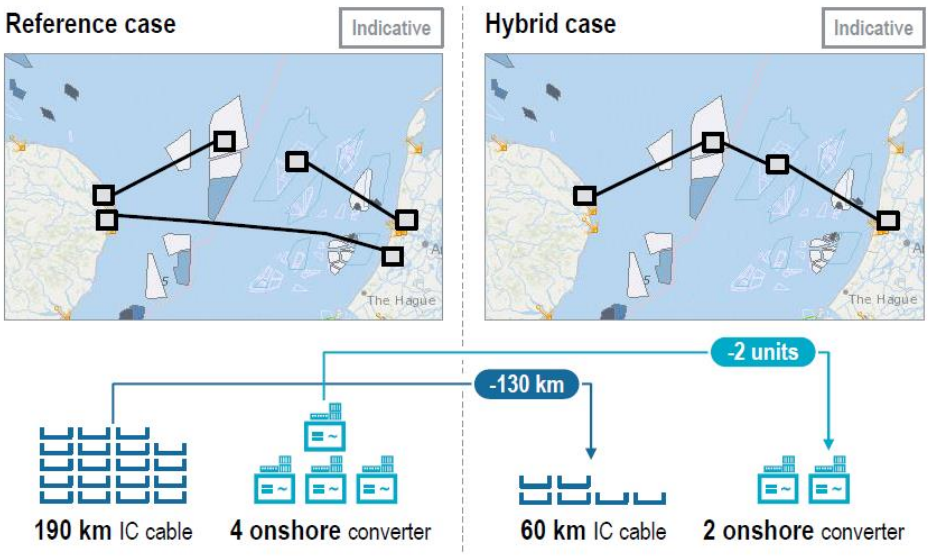


Figure 44 - Illustrative comparison between separate wind evacuation transmission assets and point-to-point interconnector compared to a hybrid approach, combining the two types of assets [42].

A grid topology in which wind evacuation transmission assets are combined with interconnection use will thus be cheaper. However, it is questionable whether this is a realistic assumption, since it is unlikely that an equal amount of interconnection capacity will be realised in such a scenario. Therefore, in a fair comparison, it is assumed that a MOG topology will not result in reduced costs but rather in more interconnection capacity available. This is assumption is still based on the cost-reduction potential, but takes a different scenario as the reference. Thus, the working assumption is that for the same amount of costs, a MOG topology would offer more interconnection capacity than a pure radial (business-as-usual) topology would realise. Put differently; if part of the costs of the transmission assets is paid for by its interconnection use, this results in lower connection costs for offshore wind farms.

B3: CO_2 VARIATION

A MOG could result in a net decrease of CO_2-emissions. The most significant impact on the amount of CO_2 (equivalent) greenhouse gas emissions will come from the development of renewable energy sources. However, within this project, the amount of renewable energy production is fixed within a scenario (205 GW of offshore wind in 2050 for the High wind scenario). Nonetheless, the total amount of CO_2-emissions emitted can still be dependent on the type of grid topology chosen to connect the windfarms.

Firstly, a MOG will result in an increase in the capacity credit of the offshore wind generation. The capacity credit refers to the total amount of *certain* wind generation. As wind power is a variable source, wind electricity output varies. The average of this varying wind output defines the capacity factor of a single wind turbine. The capacity credit is a measure of the total amount of generation power that is constantly produced by wind turbines in the system. This effectively entails the amount of conventional generation that can be completely displaced by wind generation. A MOG increases this capacity credit. This is due to 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 [43].

As wind production depends on wind speed – a local parameter – a larger geographical area thus entails a larger amount of wind power that is always available. This only holds, however, if this production can also be transmitted to the desired place: which is true in a MOG, but not in a radial grid topology. For example, if there is hardly any wind in the Dutch and German parts of the North Sea (assuming therefore high electricity price), but there is a large amount of offshore wind production in the seas surrounding Northern England (assuming therefore a low electricity price), a MOG would enable this wind production to be transmitted to the continental European system. For the continental European system, this would increase the total amount of wind production that is certain to be produced at all times, hence it increases the capacity factor. This displaces conventional (fossil fuel) power generation, resulting in lower CO_2-emissions.

Secondly, a MOG would increase coupling between different time zones, contributing to a better spread of total system peak load and hence a reduction of the maximum system peak load ('load-flattening'). The peak of the power demand usually occurs in the evening. If regions have different time zones, this usually means that the peak load of region A will not coincide with the peak load of region B. By interconnecting these time zones, the burden of satisfying these peak loads can be spread over multiple countries. By means of the interconnection, the peak load of the total system can be reduced. 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 entail a reduction in the amount of gas-generated power required, hence a decrease in CO_2-emissions. However, as a future energy system is envisaged to become more supply-driven rather than the current demand-driven approach, it is unclear to what extent this benefit will be a significant factor in 2050.

Thirdly, a MOG can contribute to a better utilization of the (potential of) different renewable energy sources within the European system. A better interconnected grid allows countries to focus on their specific comparative advantages with respect to different renewable energy sources. For example, a country that is very suitable for a high penetration of PV electricity generation could make use of wind energy generated in other countries throughout the night using a MOG (and vice versa). By doing so, the countries would not need to rely upon conventional power plants to provide power throughout times in which their domestic renewable energy production supply is not large enough to satisfy demand. In doing so, a MOG decreases overall CO_2-emissions.

Finally, as a MOG leads to an increase in market integration, it could also lead to more efficient production plants. Less-efficient (in monetary terms) generation plants will be pushed out of the market by economic forces due to enhanced market integration. This move towards more efficient generation plants would also decrease the total amount of CO_2-emissions. This benefit only holds however if a sufficiently high price for CO_2-emissions is set (either via ETS-system or direct tax) and some generation would still be fossil fuel based. Only then would it result in less-efficient (in terms of CO_2-emissions) power generation plants being pushed out of the market.

B5: GRID LOSSES

An important differentiator between different kinds of grid topologies is the quantity of grid losses associated with the grid topologies. Lowering the grid losses has been an important motivator for HVAC meshing: the grid losses for HVAC lines and cables are directly related to the square of the current transmitted over the connections. As meshing decreases the current strengths, it decreases grid losses. This benefit would in principle also apply to a HVDC MOG: meshing decreases the current strengths applied and decreasing these current strengths decreases the grid losses.

However, HVDC systems also require the use of converters. Although for longer distances – or underground or subsea systems – HVDC have lower losses than HVAC systems, HVDC systems still have losses. These losses occur in both the cables as well as the converters, where the latter are dominant in the amount of losses. HVDC meshing could reduce cable losses, but could also increase converter losses since more converters would be operating at power levels below their nominal capacity, which has a negative impact on their relative efficiency. The variation in grid losses thus depends on the relative predominance of cable losses versus converter losses and the relative efficiency of HVDC converters compared to their nominal power rating.

Nevertheless, an HVDC MOG could reduce grid losses in another way. The existence of a meshed HVDC grid could reduce grid losses in the onshore HVAC grid. This is heavily dependent on the specific interaction between the HVDC offshore and the HVAC onshore system. For example, HVDC facilitates better controllability of power flows which enables system operation strategies which optimise towards the lowest amount of grid losses possible. As a result, an HVDC MOG could reduce the amount of loop flows in the onshore grid since power flows can be actively steered. Reducing the occurrence or size of these loop flows could reduce grid losses. However, the exact effects of the HVDC MOG on the onshore grid losses remain unclear until different operational strategies have been modelled in more detail.

B6: SECURITY OF SUPPLY - ADEQUACY

The adequacy of the power system refers to the existence of sufficient facilities within the system to supply demand. It evaluates whether the system is adequately equipped to supply demand, also in case of (unscheduled) outages of transmission equipment. In order to do so, there needs to be sufficient generation capacity available as well as adequate transmission and distribution networks with sufficient capacity. A MOG would significantly improve the adequacy of the system compared to radial wind evacuation connections. As a MOG would create alternative paths for power evacuation, an outage of the primary connection to shore would have no or smaller effects compared to the radial approach.

This feature is also already included in the 'RES integration' benefit category, as an improved availability of the offshore power grid facilitates the integration of wind. However, it also has wider system benefits as the total adequacy of the system is improved by having more alternative paths (redundancy) available. The increase in redundancy is thus not 'double counted', but should rather be approached as a single feature offering multiple benefits. Normally, the benefit of redundancy is expressed in terms of 'value of lost load' (VOLL) as the redundancy prevents an outage that would have otherwise occurred. However, as the offshore grid is assumed to have no load, this indicator is not suitable. Rather, the improvement in system adequacy should be seen in terms of prevented 'value of lost renewable energy production'. Furthermore, an important security criterion for the adequacy of the system is that an offshore failure should not lead to an onshore disturbance. The addition of alternative paths by means of a MOG increases the easiness by which this security criterion is complied with, because a single outage can be (partially) compensated by the available alternative paths for wind evacuation.

ASSESSMENT

In the preceding Sections, a total of 28 separate benefits associated to the development of an HVDC MOG have been identified. They have been listed per benefit category in Table 16 below. As a preliminary analysis, it has also been assessed to what extent these benefits will have a sizeable impact, how likely it is for the benefit to take place and who or what the main beneficiaries of the benefits would be. Both the impact as well as the likelihood has been assessed on a one to five scale based on expert interviews (five entails large impact and large likelihood respectively). As for the main beneficiary(ies), a number of potential beneficiaries have been identified, including governments, TSOs, consumers, society ('citizens'), wind farm developers, storage owners and non-wind power plant owners. In this first assessment, only the direct beneficiaries are included: for example, a decrease in curtailment benefits the wind farm developer, but could eventually – depending on regulatory arrangements – also benefit the TSO and/or consumers. However only the wind farm developer is included in this table as a direct beneficiary.

Table 16 - The significance or impact, likelihood or certainty and the main beneficiary(ies) of each of the identified benefits.

#	BENEFIT CATEGORY	BENEFIT	SIGNIFICANCE / IMPACT (1 - 5)	LIKELIHOOD / CERTAINTY (1 - 5)	MAIN BENEFICIARY
1	*Socio-economic welfare*	Price convergence	5	5	Society, consumers, power plant owners
2		Reduced market volatility	3	4	Society, consumers, power plant owners
3		Improved balancing market access	3	4	TSOs
4		Reduction in redispatch costs	3	2 *	TSOs
5	*Renewable Energy Sources (RES) integration*	Alternative pathing for wind evacuation	4	4	Wind farm developers, TSOs, society
6		Improved access to storage	4	4	Storage owners, TSOs
7		Decrease in wind power curtailment	2	3	Wind farm developers
8		Improved demand opportunity	2	3	Wind farm developers
9		Lower connection costs of wind parks	2	2	TSOs
10	*Variation in CO_2-emissions*	Increase in capacity credit	4	5	Society
11		Reduction of peak load	2	5	Society, TSOs
12		Better utilization of different RES	3	4	Society
13		More efficient production units	3	4	Society, consumers

14	*Societal well-being as a result of RES integration and a change in CO_2-emissions*	Reduction of onshore grid reinforcement	3	3 *	TSOs, DSOs, society
15		Decreased environmental impact	2	3	Society,
16	*Variation in grid losses*	Reduction in onshore HVAC grid losses	2	2 *	TSOs
17	*Security of supply: Adequacy to meet demand*	Increase of adequacy by alternative pathing	4	4	TSOs, society
18	*Security of supply: System flexibility*	Increased flexibility in operation	4	4	TSOs
19		Levelling out of uncertainties & variations in wind production	3	4	Wind farm developers, TSOs
20	*Security of supply: System stability (security)*	Improved power oscillation damping	3	4	TSOs
21		Provision of synthetic inertia	2	3	TSOs
22		Provision of black-start (assisting) capabilities	1	3	TSOs
23		Reactive power compensation and active voltage stability support	4	4	TSOs
24	*Security of supply: resilience*	Increase in resilience of power system	2	4	TSOs, society
25	*Other*	Possibility of gradual development	4	4	TSOs
26		Support for European industry	3	4	Governments
27		Geopolitical advantages	4	4	Governments
28		Increased European integration	3	4	Governments

** Benefit identified in interviews, but widely divergent opinions among interviewees on the likelihood of occurrence of this benefit.*

DISCUSSION

The analysis of these benefits is meant as a first qualitative assessment of the potential benefits of an HVDC MOG. It remains, however, challenging to identify these benefits for an unspecified grid since some benefits are highly dependent on the exact specifications of the grid, its interactions with the onshore grid and the applicable legal and regulatory arrangements. A full assessment of the benefits of a MOG is thus dependent on further iterative work. Because a clear analysis of the benefits of such an offshore grid also impacts its specifications and development, this needs to be performed in an iterative process. Within the remainder of PROMOTioN, this will

be partially covered in an already ambitious step to execute a full cost-benefit analysis of detailed grid topologies in conjunction with recommendations on the necessary technical, legal and financial barriers still to overcome. In this regard, PROMOTioN provides the first comprehensive analysis of the development of an offshore grid, as opposed to more theoretical or hypothetical analyses performed before.

However, future work could improve this first assessment of benefits. Some benefits with regards to socio-economic welfare will be modelled in detail by FGH. Based on this analysis, it could be possible to execute a first-order estimate of some of the other benefits. The study performed by FGH will result in the quantification of power flows over the cables that form the MOG and a system-wide merit order detailing which power plants deliver power. In principle, from this information, many other benefits could be quantified. For example, it would produce the required information in order to estimate grid losses, the increase in capacity credit, reduction of peak load, dispatch of more efficient power units and decrease in wind power curtailment. In order to provide more insight into the benefits of a MOG, it could be useful to use these data to provide a first-order quantitative estimate of these benefits. Nonetheless, not all benefits can be quantified in that way and some benefits may not be quantifiable at all.

Some other benefits may only be researched further in a more detailed modelling of the operation of the MOG. For example, detailed analyses of several aspects of security of supply are quite dependent on the operation of the grid. This is also contingent on protection strategies and operational control schemes. Furthermore, it may be useful to subject the benefits that will be quantified to a sensitivity analysis. As a next step in the qualitative assessment, further work could still be done. For example, a more detailed assessment of the significance and likelihood per benefit could be executed by assessing this from the perspective of multiple stakeholders. This also holds for assigning some kind of weighing criteria to capture the outcome of the cost-benefit analysis in smaller set of compact indicators. The weighing factors could be assigned different values in a type of sensitivity analysis to reflect the different interests of several stakeholders.

Furthermore, this first qualitative assessment could be repeated in more depth once the final grid topologies have been developed. This will provide concrete insight into the amount of interconnection to be constructed between countries, the landing points of offshore wind connection and the exact lay-out of the grid. This will provide concrete information that can be used for a second round of interviews and a wider consultation amongst the stakeholders involved. For example, the potential additional flexibility in operation that a MOG would offer, could be assessed in more detail by discussing concrete grid topologies with the System Operations departments of several TSOs. Benefits that cannot be assessed quantitatively could be assessed qualitatively in more detail in that way.

Lastly, although the high complexity of the project warrants the need for simplicity, it is crucial to ultimately combine both the costs and benefits of the development of the offshore grid in one comprehensive analysis. The main reason to do so lies in the fact that the optimisation of either maximum benefits or minimum costs will most likely not result in the 'best' option that will maximise for the added value of society (c.f. profit by subtracting costs from benefits). As the optimal value for society should be the goal of the optimisation of the possible development of a meshed HVDC offshore grid, it is vital to include this objective in the final analysis of the overall costs and benefits of the possible development of the offshore grid. This first qualitative assessment of the potential benefits of the MOG forms a start for that analysis.

CONCLUSION

Large scale renewable energy production is required to conform to international climate agreements and in order to bring climate change to a stop. The development of such large amounts of renewable energy production units is demanding. Its integration into the power system is, however, just as challenging. Whereas offshore wind energy seems attractive due to the high and relatively stable wind speeds at sea, it also requires advanced, expensive and complex grid technologies. Therefore, research is being conducted into how such large amounts of renewable energy can be integrated into the power system. The PROMOTioN project is part of these research efforts and investigates how a meshed HVDC offshore grid can be developed in a cost-effective way.

Being a leading international Transmission System Operator, TenneT is actively contributing to research into new grid technologies and future developments. As part of these efforts, TenneT is the leading partner for the work package within PROMOTioN that is responsible for the integration of technical, economic, financial and regulatory analyses. In order to do so, TenneT will execute a cost-benefit analysis of several grid topologies in cooperation with amongst others Tractebel Engineering and FGH. In order to do so, all benefits that a MOG could potentially offer need to be identified, assessed and if possible quantified.

An analysis of potential benefits of a MOG was previously lacking. Although a standardised CBA methodology exists for the purpose of evaluating power grid developments, this methodology was not suitable for the evaluation of a complete additional system. However, even the adapted CBA methodology only contained a number of benefit categories without a full assessment of the potential benefits of a MOG. This report builds on that work by delivering a first complete overview of all potential benefits of a MOG. These can subsequently be assessed in more detail and if possible and appropriate, quantified and monetarised.

In total, using ten different benefit categories, 28 different potential benefits have been identified. These benefits vary in impact, likelihood and main beneficiary but all have in common that a MOG would offer these benefits whereas other grid topologies would not offer such benefits or only to a smaller extent. Depending on the final grid topology of a MOG, some benefits may not be valid anymore or have a different impact and likelihood than currently anticipated. Therefore, another qualitative assessment of the benefits of a MOG should be executed once the topologies have bene finalised. Using that information, it can be assessed with more certainty which benefits will hold. This is important information to assess whether a MOG would offer enough additional benefits to outweigh its additional costs compared to a radial grid topology.

Even then, another question remains, however. Are there any realistic alternatives to achieve the ambitious climate goals without a MOG to connect large amounts of offshore wind production? It remains uncertain to what extent it would be possible to comply with the international climate agreements without large amounts of offshore wind energy. Moreover; is it possible at all to integrate up to 200 GW of offshore wind energy in the North Sea without some form of meshing using advanced HVDC technologies? It remains uncertain whether radial grid topologies could deliver the required amounts of interconnection, flexibility, adequacy and security in order to integrate such large amounts of offshore wind energy. The development of a meshed HVDC offshore grid may not be so much of a choice, but could rather be a necessity. It remains quintessential in that case as well to clearly highlight which benefits a MOG could offer. Political and societal support for the development of a MOG will only be provided if its benefits and the need for its development can be clearly explained. For that purpose, this document also provides a first step.