D12.5 Deployment Plan for Future European offshore Grid Development. Short Term Projects.
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DISCLAIMER

The projects included in this document, are projects identified by PROMOTioN as potential opportunities for early adoption of HVDC equipment for multi-terminal or meshed use. This represents for PROMOTioN the first steps to identify potential opportunities to industrially test HVDC equipment prior to commercial deployment.

While we are thankful for the support and cooperation given by PROMOTioN partners to allow us to use planned or potentially real situations to test our both technical and non-technical research, we realise the complexity of such projects, and that our work is but a small subset in the decision making process, to actually go out and build. The work written here describes hypothetical projects and although approached from a number pragmatic perspectives. It does not commit any party to follow up or act on our recommendations.

The work is intended to illustrate how research work done within the PROMOTioN framework may be used to analyse and support the preparation and development of these projects. The analysis done has used data provided by our partners which may or may not be true to the final configuration of a project. PROMOTioN has used simulation and theoretical analysis to try to assess the benefits of its proposals and link these to our longer term conclusions and recommendations.

This document has restricted access and is not generally available (i.e. no publication on our website, and no active dissemination) beyond the PROMOTioN consortium and the European Commission Services. This document should not be provided to parties outside the consortium or those involved in the projects without written permission of the PROMOTioN Project Manager.
SUMMARY

This document is a supplement to the PROMOTioN project deliverable D12.4 Deployment Plan for future European Offshore Grids (the Deployment Plan). The Deployment Plan is intended to give guidance to stakeholders in which choices are best to realise an efficient, cost effective and secure offshore grid to ensure optimal evacuation of wind generation to shore and interconnection of North Sea countries; what steps are required to steer parties towards a selected scenario; and when these steps need to be taken (short-, medium- or long term).

An important goal of the Deployment Plan is to identify planned or existing transmission projects where solutions and recommendations of PROMOTioN could be implemented already in the short-term. This would significantly reduce the perceived level of risks due to the combination of innovative measures, at the same time laying down the first steps for the deployment of meshed HVDC grid. The primary focus of this document is on a number of short-term projects to deploy & pilot technical, regulatory, market and economic solutions in such a way that complexity increases gradually and risks are manageable.

The work done by PROMOTioN on these projects is as such a preliminary analysis and support of the project developers. In all cases, the work performed by PROMOTioN has been performed in cooperation with the developers (TSO or other stakeholders). However, the work done represents no commitment from these organisations to develop the opportunities discussed. More strongly, we anticipate that none of these cases may go further without early EU, governmental, manufacturers support and encouragement given by the developers.

The TSOs have to date indicated that the risk of such projects is too high, given the amount of new technology required. Also, they consider that despite similar/or same specification of manufacturer equipment, there is insufficient guarantee and clarity regarding liability where interconnection of different systems is deployed it will operate safely. ENTSO-E is planning a new programme to address equipment interoperability. However, unless this programme is able to incorporate the projects in our analysis or similar projects in parallel to the proposed development programme, then the start of deploying multi-terminal equipment will be pushed into the period from 2030 and beyond.

The projects that PROMOTioN analysed were based on the ENTSO-E TYNDP 2018. PROMOTioN identified a series of projects with increasing complexity. This analysis focuses on examples only, where PROMOTioN received a mandate to perform support work. The deployment of these projects in the short term requires a step-wise increase in the level of complexity and new technologies, and market & regulatory frameworks to be tested, see Figure 0-1.
In this document three real projects and one hypothetical proposal are reviewed:

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

2. WindConnector DC protection. Installing DCCB on an offshore platform to protect Dutch onshore grid from the faults in the hybrid cable between Dutch and British offshore windfarms.

3. Bornholm island CleanStream energy hub. Offshore hub for hybrid infrastructure combining functionality of offshore energy evacuation and interconnection between Denmark, Poland and potentially Germany.

4. Additionally, a hypothetical 3-node system connecting North Sea countries was proposed to showcase potential socio-economic benefits that could be achieved by building meshed grid.

For each of these projects a range of studies in technical, regulatory, commercial, economic and financial dimensions was performed. The depth and scope of studies differ significantly based on the information and support available from project promoters. Nevertheless, PROMOTioN has addressed a large proportion of the uncertainties. It is believed that the next step is to carry a more detailed feasibility analysis in the commercial environment with an actual intention to implement one or more of these initiatives.

PROMOTioN has shown that these projects could not only resolve existing barriers towards deployment of the offshore grids, but also lay down the first steps that are necessary if high ambitions towards offshore wind integration are to be realized. From our analysis, to date each of the above projects could potentially show positive net benefits for stakeholders.

For each of these projects a range of studies in technical, regulatory, commercial, economic and financial dimensions was performed. The depth and scope of studies differ significantly based on the information and support available from project promoters and where PROMOTioN is able to add value to the project promoters efforts.
Nevertheless, PROMOTioN has addressed a large proportion of the uncertainties. It is believed that the next step is to carry a more detailed feasibility analysis in the commercial environment with an actual intention to implement one or more of these initiatives. PROMOTioN has shown that these projects could not only resolve existing barriers towards deployment of the offshore grids, but also lay down the first steps that are necessary if high ambitions towards offshore wind integration are to be realized in the longer term.
## ABBREVIATIONS

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<td>AC</td>
<td>Alternating Current</td>
</tr>
<tr>
<td>ADC</td>
<td>Analog to Digital Converter</td>
</tr>
<tr>
<td>CB</td>
<td>Circuit Breaker</td>
</tr>
<tr>
<td>CEF</td>
<td>Connecting Europe Facility</td>
</tr>
<tr>
<td>DC</td>
<td>Direct Current</td>
</tr>
<tr>
<td>DCCB</td>
<td>Direct Current Circuit Breaker</td>
</tr>
<tr>
<td>DCL / DCR</td>
<td>DC Current Limiting Reactor</td>
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<tr>
<td>DSP</td>
<td>Digital Signal Processor</td>
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<tr>
<td>EMB</td>
<td>Electromagnetic Breaking</td>
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<tr>
<td>FO</td>
<td>Fibre Optic</td>
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<tr>
<td>HDC CB</td>
<td>Hybrid Direct Current Circuit Breaker</td>
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<tr>
<td>HVDC</td>
<td>High Voltage Direct Current</td>
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<tr>
<td>IGBT</td>
<td>Insulated Gate Bipolar Transistor</td>
</tr>
<tr>
<td>OWF</td>
<td>Offshore Wind Farm</td>
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<tr>
<td>PCB</td>
<td>Printed Circuit Board</td>
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<tr>
<td>PCI</td>
<td>Project of Common Interest</td>
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<td>PI</td>
<td>Proportional Integrator</td>
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<td>PWM</td>
<td>Pulse Width Modulation</td>
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<td>RCB</td>
<td>Residual Current Breaker</td>
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<tr>
<td>RTDS</td>
<td>Real Time Digital Simulator</td>
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<tr>
<td>STP</td>
<td>Short-Term Project</td>
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<tr>
<td>TYNDP</td>
<td>Ten-Year Network Development Plan</td>
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<tr>
<td>UFD</td>
<td>Ultrafast disconnector</td>
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<tr>
<td>VSC</td>
<td>Voltage Source Converter</td>
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<td>WP</td>
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1 INTRODUCTION

1.1 BACKGROUND

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

Short-term HVDC projects present the opportunity to demonstrate the HVDC technologies being developed in PROMOTioN, and which will be needed for multi-terminal HVDC projects: DCCBs, DC GIS and control and protection systems. These projects also present an opportunity to implement legal, regulatory and market frameworks which will facilitate the deployment of meshed HVDC offshore grid. Short Term Projects is a separate subtask within Work Package 12 (WP12) which aimed at identifying and analysing potential projects that could be modified to test HVDC technologies. The primary goal is to gradually increase complexity from the business-as-usual solutions (primarily point-to-point links) to multi-terminal HVDC systems.

1.2 PLANNED HVDC PROJECTS

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

Figure 3 ENTSO-E Map of proposed projects in the Northern Seas. Source: ENTSO-E TYNDP 2018
However, with the focus on interconnection, there is little detail in TYNDP of how the majority of offshore wind will be connected to the shore, despite the fact that offshore energy generation capacity in the region is anticipated to be 125GW in 2040 according to its Global Climate Action Scenario [1].

1.3 ATTITUDES TO SHORT TERM MULTI-TERMINAL HVDC GRID PROJECTS

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

1. **Too risky.** TSO management and Regulators are risk averse; TSOs are unwilling and unsure how to defend the use of HVDC CBs and protection in an untested environment towards the regulator.
2. **Too expensive.** The capital costs are anticipated to be too high. In particular, the space that is required for HVDC, multi-terminal project is large resulting in materially larger offshore platforms.
3. **The Legal & Regulatory environment is not yet ready for multi-purpose projects.** Temporary workarounds can facilitate a unique solution, but this may encounter objections from certain stakeholders. Some of the multi-purpose projects require significant alterations in the existing regulations and this is perceived to be a long process.
4. **Too complex to manage stakeholder views.** Most of the hybrid projects involve two or more countries as such the negotiation process requires agreement from at least 6 parties: the 2 TSOs, 2 Regulators, at least 2 Owners / Government, OWFs, etc. Each has its own interests and concerns. Also, the suppliers need to consider a multi-terminal option, and where more contractors involved, interoperability.
5. **There is no immediate technical need.** The projects are currently quite simple, whereby the targeted results can almost be reached without the use of new technology.
6. **Planning processes are not designed for complex projects.** The current planning process is designed for individual and uncoordinated projects that are delivered as standalone projects. This is because of limitations in connections to the onshore grid, when compared to the size of the projects, the non-technical barriers that we describe further in this document and the short planning horizon for projects – this does not make a more strategic approach easy to deliver.
7. **Lack of technical expertise.** There is also insufficient experience within the TSOs to consider HVDC multi-terminal connections. All studies that have been performed in Europe so far have mainly academic character and haven’t left lab environment, i.e. have not resulted in commercial or pilot projects. The only existing real experience is on land in China.
8. **Procurement and interoperability risks.** There is little to no experience with building multi-vendor HVDC projects. It is expected that in such systems performance guarantees from the manufacturers would be withdrawn as this conflicts with conventional turn-key project approach. Equipment suppliers ensure operational stability based on the extensive in-house testing of various equipment and systems. In multi-vendor environment full-system testing is currently impossible as it would mean sharing technical details and specifications with competitors in a highly non-standardised industry.

1.4 MOTIVATION

As a result, PROMOTiOn has, evaluated the technical feasibility, costs and benefits, risks and the legal and regulatory barriers of real existing or planned projects which may be suitable for testing new HVDC equipment. It is believed that deployment of multi-terminal multi-vendor grids has to be achieved in a step-wise manner, gradually increasing complexity of the projects and keeping the above-identified risks tolerable. The diagram in Figure 4 in the direction from left to right shows how projects can evolve from the current state, and which already planned initiatives fulfil the criteria.
In PROMOTioN Short Term Projects subtask we focused on three existing or planned projects and one hypothetical demonstrator, each with a different potential to utilize multi-vendor technology, HVDC protection, and new regulatory & market schemes. These projects, in the order of complexity are:

1. **SouthWest Link – Hansa Power Bridge DC Connection.** DC-side connection of two HVDC corridors with the goal of reducing grid losses, increasing availability and interconnection level between Sweden and Germany.
2. **WindConnector DC protection.** Installing DCCB on an offshore platform to protect Dutch onshore grid from the faults in the hybrid cable between Dutch and British offshore windfarms.
3. **Bornholm island CleanStream energy hub.** Offshore hub combining functionality of offshore energy evacuation and interconnection between Denmark, Poland and potentially Germany.
4. **Additionally, a hypothetical 3-node system connecting North Sea countries was proposed to showcase potential socio-economic benefits that could be achieved by building meshed grid.**

These projects’ geographic location is given on the map in Figure 5, where also some other opportunities are identified.
1.5 SCOPE OF STUDIES AND SUMMARY

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Realisation of each of the above-mentioned projects entails its own barriers and complexities related to technical, regulatory, economic or financial dimensions. PROMOTioN has addressed known issues based on the availability of information and support from project promoters. This resulted in different scope of studies and level of detail in the analysis done for each of the short-term initiatives as it is shown in Figure 6.
SouthWest Link – Hansa Power Bridge (SWL-HPB) DC connection

As such, the most comprehensive analysis was performed for SouthWest Link – Hansa Power Bridge (SWL-HPB) DC connection. For this project PROMOTioN has analysed in detail grid topologies, technical requirements and implications, conducted Cost Benefit Analysis (CBA) of various configurations and DCCB technologies, gave recommendations for some of the regulatory, market and commercial aspects. This proposal, if implemented, could be realized by 2028, and compared to the other two initiatives requires limited alterations in the original scope. Furthermore, the DC link would be located onshore which further reduces the complexity and allows to avoid some of the risks inherent to offshore environment. The focus is on DCCB and multi-vendor DC connection which allows to reduce losses from energy conversion and increase availability of the transport corridor between Sweden and Germany.

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

There is a potential to apply for Connecting Europe Facility (CEF) funding both for the engineering works, as well as for the actual component procurement seeing the innovativeness of the project. In order to be realized this project will require such an external financing from EU in order for TSOs of Sweden and Germany to opt for it. Without such an assurance, it is unlikely that it may be realized. The primary value of this project for the realization of future meshed grid is the first real life implementation of DCCB, simplified multi-vendor environment and DC meshing. By implementing it onshore, significant cost reduction and de-risking is achieved.

WindConnector DC Protection

For the DC protection of WindConnector it is suggested to install a DCCB on the cable connecting two offshore wind platforms so that the faults on any side do not propagate to the other one. PROMOTioN has focused on the analysis of transient phenomena which would occur in case of DC faults on the hybrid cable between two offshore platforms and on the potential gains enabled by DCCB. Additionally, an overview of procurement and interoperability issues was summarized based on the insights and opinions provided by Dutch TSO TenneT. Finally, PROMOTioN has done an analysis on different market schemes, i.e. offshore and onshore bidding zones, which are relevant for WindConnector. This is however included in the main deliverable D12.3 and will not be showcased here.

Similarly, to the SWL-HPB, this project employs a DCCB but now installed offshore. Based on a high-level cost estimate, added costs for DCCB and extra space on the platform may reach up to ~€120 mln. This is a rough estimate which could be improved by having more insight into the costs of offshore platforms and supplementary equipment needed to enable DC protection. Due to the fact that this is an offshore project, the risks of achieving a successful implementation are perceived even higher and stakeholders even less willing to approve such projects. Incentives from the EU are needed, also seeing that different stakeholders have opposite views on the benefits from DC breaker as compared to its costs. Potential for CEF funding is to be investigated further but in any case support will be necessary. The timeline for this project is to be realized before 2030.

We recommend project stakeholders to assess the potential of offshore DCCB for WindConnector further and in a higher detail. From multiple consultations with industry experts, it is suggested that being in a commercial environment, many hurdles can be solved in a more pragmatic, fast and optimal way.

Bornholm island CleanStream energy hub

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

While ongoing political negotiations on new offshore wind in Denmark include a Bornholm energy island project, the design of the project CleanStream is still ongoing and in a very early stage, so the relevance of the pre-feasibility analysis of CleanStream is high. Also, there is a window of opportunity, it is easier to plan for complex technology and develop design which will allow for new technical solutions. The concept of the project is an energy hub located onshore, on the existing Bornholm island, so it imposes less costs, less risks for new technology and does not have the space constraints present in artificial island structures. Besides OWFs connected to the energy hub at Bornholm, the project includes an interconnector between Denmark and Poland, which is already been subject to interest from the two countries and is included as a direct link in the TYNDP 2018. In summary, there is great interest and commitment to find technical and economic solutions to realise the project. What is needed is to incentivize a more innovative approach which promises significant increase in socio-economic welfare as it is shown in PROMOTioN. This project has to be seen as a representative building block for the full-scale future DC grid. It is believed that first parts of the project can be in place by 2030. We note that Bornholm island offers an unprecedented opportunity to minimize the amount of infrastructure that would be required otherwise to connect 4 different EU states. Its geographic position between Nordic and Central European regions makes it a perfect candidate for the development of a first multi-terminal European energy hub. In addition, we have proposed an approach for the step-wise development of the hub in order to further de-risk its implementation, eliminate technology-related difficulties and attract finance.

1.6 HOW TO READ THIS DELIVERABLE

For each of the projects a limited research and analysis were done based on the current project phase, available information and stakeholder involvement. The following chapters of this Deliverable contain a full overview of the studies that were performed for each STP respectively. Each chapter, therefore, can be read as an independent report with its own conclusions.
2 SOUTHWEST LINK AND HANSA POWER BRIDGE DC CONNECTION

2.1 INTRODUCTION

This chapter focuses on the idea for a short-term initiative SouthWest Link- Hansa Power Bridge link, modifying this in order to demonstrate the benefits of HVDC protection technology. From an innovation perspective, the proposed project is defined by first time application of a multi-vendor HVDC protection system in Europe. In a proposal to "upgrade" this project our goals are to improve the efficiency of the infrastructure by reducing effective losses through conversion, and facilitating the security of supply both in availability/resilience and flexibility.

2.2 A DC-SIDE CONNECTION BETWEEN TWO HVDC CABLES

The point-to-point HVDC links SouthWest Link and Hansa Power Bridge both have one of their terminals in the same location, Hurva, Sweden. They are based on similar technology and will use the same DC operating voltage. This raises the question whether connecting these links on the DC side into a multi-terminal connection would be beneficial. The link can be realised as a project extension without significantly altering existing plans. With the proposed DC connection the power could be fed through the node in Hurva without passing through two converter stations. This implies power loss savings, which translate into significant savings on operating cost over the lifetime of the installations.

Such a development would bring lots of experience in designing, deploying and operating multi-terminal DC (MTDC) links in Europe. These skills are currently lacking. Obtaining such experience is necessary for further deployment of MTDC infrastructure in Europe, including meshed HVDC networks and offshore MTDC nodes.

The risks are manageable, and financially it is attractive. No major capital-intensive modifications need to be made to the original design of the two links and they can be operated just as originally intended, by disconnecting the proposed added circuitry. Also, since the amount of added equipment will be modest, the capital expenditure should be small in relation to the total projects CAPEX and additionally realisable benefits.

The main data for the two links can be seen in Table 1 and a map showing their approximate locations is found in Figure 7.

<table>
<thead>
<tr>
<th>Table 1 Main data of SouthWest Link and Hansa Power Bridge</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>SOUTHWEST LINK</strong></td>
</tr>
<tr>
<td>Investment (MEUR)</td>
</tr>
<tr>
<td>Power (MW)</td>
</tr>
<tr>
<td>DC Voltage (kV)</td>
</tr>
<tr>
<td>Length Cable (km)</td>
</tr>
<tr>
<td>Length DC OH Line (km)</td>
</tr>
<tr>
<td>In Operation (planned) Year</td>
</tr>
</tbody>
</table>
† = of which 180 km offshore

2.3 SOUTHWEST LINK

The SouthWest Link is a combined AC and DC transmission link in Sweden. Only the DC part is considered here, which is embedded in the Nordic synchronous zone. This part consists of two parallel onshore VSC HVDC links running from Barkeryd (SE) to Hurva (SE). The links are partly overhead lines and partly land cables. The cables are provided by NKT, formerly ABB, whereas the converter stations are built by GE, formerly Alstom. The converter stations are configured as two parallel symmetrical monopoles. The planned date for commissioning is set to October 2020.

2.4 HANSA POWER BRIDGE

The Hansa Power Bridge is a 700 MW subsea HVDC link between Hurva (SE) and Güstrow (DE). It will connect the two different synchronous areas of Svenska Kraftnät (SvK) in Sweden (Nordic) and 50 Hertz Transmission GmbH in Germany (UCTE). The whole link is foreseen to be cabled. The planning and permission process is currently ongoing. The start of construction is planned in 2023 and commissioning should be in 2026.

The connection is of great importance in facilitating the opportunity to integrate the large quantities of renewable electricity generation that will be established in Sweden and the Nordic region. The increased trading capacity between Sweden and Germany makes it possible to export larger quantities of renewable energy during periods
of surplus in the Nordic countries, but also to import when large surpluses in the rest of Europe give lower prices there than in the Nordic countries.

The increase in trading capacity is also of great importance to be able to import more power during those times when the weather-dependent electricity production in Sweden and the Nordic region, together with other production sources produces insufficient power to cover consumption. This is especially important as the decommissioning of Swedish nuclear power is expected to lead to more occasions with a serious risk of power shortage in southern Sweden.

2.5 TECHNICAL ANALYSIS

The DC connection of the SouthWest Link and the Hansa Power Bridge, while largely attractive from an operational point of view, leads to several interesting control and protection challenges. This chapter will provide analysis around work that has been performed proposing methods by which the overall system could be controlled and protected.

2.5.1 OPTIONS FOR ELECTRICAL CONFIGURATION OF THE DC CONNECTION

The single-line diagram of the proposed DC connection in Hurva can be seen in Figure 8, indicated in red print. This is a minimum version including one HVDC circuit breaker that allows for connecting either of the DC lines going to Barkeryd directly to the line going to Güstrow. It also allows for rapid separation of the two lines in case of a fault on either of them so that the fault will not affect the operation of the other. It is not foreseen that both of the SouthWest Link lines will simultaneously be part of the new connection; one of them will still function as a point-to-point link.

The arrangement in Hurva will differ from the ones that have commonly been studied in an MTDC context in that there will be two converter stations in parallel in that node, one belonging to the SouthWest Link and one from Hansa Power Bridge. In steady state, there may be advantages (such as reduced losses, or improved maintainability/operability) to disconnecting one of the converters during MTDC operation (preferably the one from the SouthWest Link since it has lower rating). This needs further explicit analysis.
Figure 8 Simplified schematic showing the proposed connection in red print.

Figure 9 Detailed schematic of SWL-HPB DC Connection including one DC circuit breaker (DCCB) per pole and high-speed switches for reconfiguration. Note that only one SWL point-to-point system will be connected to the HPB at a time.

Note that although there are six converters, no benefit has been identified in connecting all six converters to make a six terminal system, therefore the main scenario under consideration in this document is the four terminal system for which two of the SouthWest Link converter stations are connected to the two Hansa Power Bridge converter stations. In the rest of the chapter, for simplicity only one symmetrical monopolar system of the SouthWest Link will be presented, but the analysis applies equally to the other identical system, and indeed either system could be used in the DC connection in the same manner by reconfiguring the high speed switches.

2.5.2 CONTROL OF THE HVDC SYSTEM

In order to successfully operate the overall system – including the converter stations within both the SWL and the HPB in addition to the switchgear within the DC connection – a control structure and strategy has been designed. Droop characteristics to define the voltage control and the power flow across the network have been defined. Switching sequences to bring the DC connection in and out of conduction have been proposed, and the communication requirements for such a control scheme have been defined.
2.5.2.1 POWER AND VOLTAGE DROOP CONTROL OF CONVERTER STATIONS

Droop characteristics have been developed such that there is no requirement for control mode switching between operational modes. Fixing the control method in this manner results in operation at a slightly lower voltage than necessary during point-to-point operation of one of the SWL or the HPB, therefore it may be attractive to only use this control mode immediately before, during, or immediately after conduction of the DC connection. However, it has been developed such that the DC connection can be well controlled without any requirement for changing voltage/power droop parameters when switching between different control states. The applied droop characteristics, Figure 10, ensure that the voltage and power are controlled appropriately - both when the DC connection is conducting and also when the DC connection is not conducting (e.g. before connection or following disconnection). Considering the case when the DC connection is not conducting, on the SWL the Barkeryd station injects power into the DC system, increasing the DC voltage until the droop at the Hurva station (black line) absorbs the same power that is injected. Similarly, for the HPB, the Güstrow station absorbs power and the droop at the Hurva station (red line) controls the voltage. Before the DC connection is made, there is a voltage imbalance across the connection (e.g. ~10 kV), and the action of closing the DC connection results in a balancing of the voltage between the SWL and the HPB, the rate of which is controlled by the very large series inductor in the connection. After the voltage is balanced between the SWL and the HPB, the voltage at Hurva is near to the nominal and no real power is absorbed or injected at the Hurva converters, with the power instead being transferred through the DC connection. This method allows operation of the system in each mode without control mode changes during operation, at the penalty of a marginal decrease in possible power transfer on one of the systems in normal operation – given that a slight reduction in voltage is implied for one of the point-to-point systems in the operation mode for which the DC connection is not conducting. This operating mode is considered to allow successful operation when switching the DC connection (in or out), and if one point-to-point system or the DC connection is out of service then modifying the droop settings such that they are optimised for point-to-point transmission would be advisable.

![Figure 10 Droop characteristics for the four connected converters in case of DC connection and following DC disconnection due to a fault](image)

2.5.2.2 SWITCHING THE STATE OF THE DC CONNECTION

No requirement for advanced switching sequences is foreseen with the presented control structure. Switching the DC connection into conduction can be performed simply by ordering closing of the switches in the DC connection.
(the order of which would be controlled within the DC ‘switching station’ or SS). Likewise, switching the DC connection from conduction into the non-conducting state requires only the ordering of the opening of the switches in the DC connection in a specified order.

The DCCBs in the DC connection (one per pole) operate following a DC fault on either side of the DC connection. The detection of the DC fault is performed by an HVDC IED, which bases its decision on measurements on both sides of the DC connection.

Given that the key benefit of the DC connection is in steady state losses over long periods of time, no significant benefit is foreseen for fast switching between modes – it is expected that it would be better for the operator to be confident in the operation. Therefore, following a fault, there is no requirement for reconnecting the DC connection quickly.

Further detail on the switching of the DC connection is included in Appendix, section 7.2.1.1.

2.5.2.3 COMMUNICATION REQUIREMENTS

Low speed communications are assumed for setting power flow scenarios and droop settings (from the control centre). There is no requirement for high speed communication between converter stations. It is assumed that reliable/redundant high-speed communication would be present within a substation.

Additional information on a possible control and communication structure is provided in Appendix B, Section 7.2.1.2.

2.5.3 PROTECTION OF THE HVDC SYSTEM

There are various options available when designing an HVDC protection system. Depending on the choice of fault isolation method (AC CB or DCCB) for both primary and backup protection there are varying trade-offs in performance and system impact. The SWL HPB DC connection is in many ways an interesting case study to examine, given that it would be a connection between two existing point-to-point HVDC systems. A key aim of a protection strategy would be to ensure that a fault on one of the HVDC systems does not cause any interruption of power transmission for the remaining healthy system. Conversely, it is important that the protection system does not become prohibitively large, have too large capital cost to install, or have significant losses that would mitigate the key benefit of the SWL-HPB DC connection.

A common suggestion for protection of multiterminal HVDC networks is using fast DCCB with additional series inductance to limit the rate of rise of fault current and prevent the rapid propagation of the fault across the network. Such inductors, however, can be physically large and expensive, and incur some steady state conduction losses. There are various options in DCCB technology, with varying operation speed and current rating (among other trade-offs). In this section several protection options will be examined, with a 2 ms DCCB and an 8 ms DCCB, and for each hardware configuration the details of the primary protection will be discussed and evaluated through time domain simulation.

In each case, focus will be placed on the impact of a fault on one existing point-to-point system (e.g. the HPB) on the other (e.g. the SWL), and if the protection system allows the healthy point-to-point system to ‘ride through’ the fault and continue power transfer. In the following simulations the continuous operation – or otherwise blocking – of the healthy point-to-point system is prioritised and highlighted. The blocking limit is based on typical expected
performance of such a converter station. For the purposes of this study, the SWL MMCs are specified according to known data about the real system and the HPB MMCs are specified to be the same. The protection sequences for the SWL – including pole rebalancing and one reclosing attempt - are known based on previous study [2], [3] and are fully implemented in the presented results.

The designed protection systems and the studies presented assume no modifications of the SWL converter control scheme is allowed - therefore the SWL control system would not require any modification or retro-fit to allow it to operate in these modes. This leads to the significant advantage – both in operational reliability as well as in cost – that the SWL requires no modification and can revert back to point-to-point operation without any control modifications.

### 2.5.3.1 DC CONNECTION PROTECTED USING DC CIRCUIT BREAKERS

Using a DCCB and an additional inductance could allow for the impact of a DC fault to be constrained to the faulted system, with the healthy point-to-point system remaining in continuous operation and continue to transfer power without interruption. In order for the healthy system to remain in continuous operation the DCCB and the additional inductance should be chosen such that the converter stations connected to the healthy network segment do not block. In order to analyse differing options, two DCCB operation speeds are chosen for analysis here: 2 ms (representing either the ABB hybrid DCCB or the SCiBreak VARC DCCB) and 8 ms (representing the Mitsubishi DCCB).

![Figure 11 SWL-HPB DC connection with one DCCB per pole](image)

The protection scheme with one DCCB utilised per pole is shown in Figure 11. In this case, primary protection is provided by the DCCB and backup protection is provided by the AC-side circuit breakers at all four MMCs. For each DCCB topology, an appropriately sized inductor has been chosen such that the SWL converters do not block following a DC fault on the HPB, Table 2. Note that in all the following simulations, because of the significant additional inductance in the system the current in the DC connection does not exceed 10 kA (including in the backup protection cases). In the following studies it has been assumed that fault detection takes 500 us in line with recently demonstrated industrial hardware [4], although it may be possible to marginally improve the speed in future hardware [5]. Because of the strict requirement for the healthy system to remain in continuous operation and not block, the additional inductance required is quite significant – 250 mH to 900 mH. This additional inductance, relatively large compared to that often considered for HVDC protection, could lead to significant additional cost. It should be noted that a 1 ms DCCB would only require an 80 mH inductor, should future DCCB technology allow this operation speed.
Table 2 Additional inductance requirement according to DCCB operation time

<table>
<thead>
<tr>
<th>DCCB Operation Time</th>
<th>Additional Inductance</th>
</tr>
</thead>
<tbody>
<tr>
<td>2 ms DCCB</td>
<td>250 mH</td>
</tr>
<tr>
<td>8 ms DCCB</td>
<td>900 mH</td>
</tr>
</tbody>
</table>

The operation of each DCCB – and the subsequent performance of the droop control – will now be analysed. Following a fault on the HPB (closest to the DC connection), Figure 12 and Figure 13, it is observed that the DCCB is able to successfully isolate the fault from the healthy network segment, showing that the DCCB successfully isolates the fault from the healthy system and the converters in the healthy point-to-point system (the SWL) do not block, with the droop control successfully redistributing the power flow such that there is no interruption to the flow in the SWL. The maximum observed energy dissipation for a single opening event is 3.48 MJ (2 ms DCCB and 250 mH) or 12.75 MJ (8 ms DCCB and 900 mH). Given that there is no identified benefit to fast reclosing of the DC connection – and therefore no requirement for a second consecutive open operation before the DCCB surge arresters have cooled – this stated energy dissipation is anticipated to be the maximum required for this application.

Figure 12 Response of primary protection with 2 ms DCCB and 250 mH additional inductance.
**Notes on other aspects:**

By selecting inductors that are large (relative to many proposed multiterminal HVDC protection schemes), the imbalance on the healthy network segments following a pole-to-ground fault is negligible and therefore there is no identified advantage to fast pole rebalancing equipment.

In each case, a dv/dt protection algorithm is used with measurements at each side of the DC connection. The required measurements may be provided by existing equipment (in the SWL and HPB) where possible, or alternatively could use dedicated instrument transformers. The algorithm used is simplistic in nature given that for any fault case the DCCB should operate – in this respect the algorithm does not need to be selective and can easily detect when there has been a fault. Overcurrent protection could be used as a backup. A 500 us delay is added to the detection algorithm to allow for the computation time of a typical HVDC protection IED. Pole-to-pole faults are used to specify DCCBs and pole-to-pole faults are applied to specify outage timings.

**Example functional requirements of the DC connection (based on design choices for 2 ms DCCB with 0.5 ms protection IED):**

Connection rated to 1.1 kA (continuous), 9 kA (instantaneous). Voltage rating of all equipment to be coordinated with the overvoltage protection of DCCB and HPB, but in the presented examples a momentary overvoltage of maximum 525 kV (line to ground) must be tolerated by the equipment in the DC connection. Given the 250 mH current limiting inductance, the DCCB should be required to isolate a peak fault current of 5 kA and 3.5 MJ per pole. Optional addition for faster recovery in case of breaker failure: additional switchgear in series for backup protection able to isolate 7 kA in 30 ms and withstand 1.5 pu voltage for 50 ms.
2.5.3.2  DC CONNECTION WITHOUT DC CIRCUIT BREAKERS

For benchmarking, the case with no DCCBs and just high-speed switches (disconnecter switches) present in the DC connection is now studied, Figure 14. It is shown that the healthy system can recover in between 550 ms and 850 ms following a worst case fault on the other point-to-point system.

Figure 14 SWL-HPB DC connection with no DCCBs and switchgear for reconfiguration of network.

Figure 15 Response of SWL-HPB DC connection with AC CB protection (no DCCB and no additional inductance) to pole-to-pole fault. Recovery on healthy point-to-point system observed in 850 ms.
Figure 16 Response of SWL-HPB DC connection with AC CB protection (no DCCB and no additional inductance) to pole-to-ground fault. Recovery on healthy point-to-point system observed in 549 ms.

### 2.5.4 PROSPECTS FOR EXTENSION

The SWL-HPB DC connection only uses DCCBs at one location given that this results in a fully selective protection strategy – i.e. the faulted segment can be isolated without de-energising the healthy segments. If one or more additional terminals were connected in the future, then there is likely to be an operational benefit in adding DCCBs in order to create a fully selective system. The exact configuration would depend on the expected power flows across the network and the anticipated network layout, but the most flexible is likely to be a fully selective strategy.

![Diagram of network connections]

Figure 17 Hurva station following DC connection
The particular case of having converter stations that are not expected to be fully utilised while the SWL and the HPB are connected results in several significant benefits that could be gained when considering future expansion. In many power flow scenarios, the power rating of the converter stations at Hurva is under-utilised, therefore connecting an additional DC line or cable to the Hurva substation would allow for an increased utilisation of the converter stations – power transfer would be possible from a new remote station to the Hurva station with only the addition of one extra converter station (at the remote station).

If there is a possibility that this might be attractive in the future, space should be left for the additional DCCBs and the other substation equipment that would be required.

2.5.5 IMPLEMENTATION

Figure 20 shows an aerial picture of the existing SouthWest Link converter station at Hurva. The existing cable route to Barkeryd has been sketched in blue. The proposed location of the Hansa Power Bridge converter station (from the public consultation) has been shown, including the proposed cable route towards Güstrow. There are two sites of approx. 60 x 100 m adjacent to both converter sites which could potentially be interesting for the placement of the DC connection equipment.
As discussed in the previous sections, the DC connection is likely to contain a DC circuit breaker. In addition, DC equipment to measure voltages and currents, to prevent overvoltages and to disconnect and earth the DC connection are needed. This is illustrated for one pole in Figure 21. A key aspect to be considered in the physical implementation are the possibilities to connect the DC connection to the existing and planned infrastructure of the SWL and HPB. The SWL has been equipped with outdoor air insulated removable link points which could be used for this purpose, and therefore does not require additional hardware changes. The design of the HPB has not yet been formalized, but it is essential that to enable the future realization of the DC connection, the HPB Hurva converter DC switchyard design foresees the provision of a physical connection point. As a minimum this could be the inclusion of sufficient space for an additional DC bay, but it may also already include the necessary equipment to make a connection so that this can be done in the future without requiring downtime.
Apart from the DC circuit breaker, the equipment required to realize the DC connection is readily available in the required ratings in air insulated implementation. In case space reduction is required, it is possible to implement this functionality in gas insulated systems. Figure 22 shows a 350 kV 4000 A HVDC gas insulated system test pole from ABB which is currently being qualified in a long-term prototype installation test in PROMOTioN. The available gas insulated equipment includes disconnectors, earthing switches, current measurements, voltage measurements, surge arrestors and air terminations. After finishing the long-term test in 2020, the technology can be considered mature with a TRL of 8.

Table 3 shows the HVDC circuit breaker technologies that have been analysed and demonstrated in PROMOTioN. All technologies are in principle applicable to realise the DC connection. The illustrations shown only show one pole, of which there will be two in an actual DC connection. In addition to the equipment shown, there will be a series reactor the size of which depends on the circuit breaker type. It is noted that with the exception of the Mitsubishi HVDC circuit breaker, the other two must be installed indoor in an air-conditioned environment. All three technologies are air-insulated, and thus have a significant footprint compared to AC circuit.
breakers. Mitsubishi claims to offer a gas insulated version of its DCCB technology, realizing further space reductions, but no further details about the design or maturity of this option are available. All three technologies have been tested, although the ABB technology can be regarded as the most mature.

Table 3 – HVDC circuit breaker technologies

<table>
<thead>
<tr>
<th>Hybrid HVDC circuit breaker</th>
<th>Mechanical HVDC circuit breaker with active current injection</th>
<th>Voltage source converter assisted resonance converter HVDC circuit breaker</th>
</tr>
</thead>
<tbody>
<tr>
<td>ABB</td>
<td>Mitsubishi Electric</td>
<td>SciBreak</td>
</tr>
<tr>
<td>Illustration: 350 kV 16 kA</td>
<td>Illustration: 320 kV 16 kA Both in and outdoor</td>
<td>Illustration: 320 kV 10 kA Indoor</td>
</tr>
<tr>
<td>Indoor</td>
<td>8 ms breaker operation time</td>
<td>2 ms breaker operation time</td>
</tr>
<tr>
<td>3 ms breaker operation time</td>
<td>8 ms breaker operation time</td>
<td></td>
</tr>
<tr>
<td>Tested up to 350 kV and 16 kA</td>
<td>Tested up to 160 kV (multi-modular) and 16 kA</td>
<td>Tested up to 80 kV (multi-modular) and 10 kA</td>
</tr>
<tr>
<td>Dimensions: 7 x 5 x 11 m</td>
<td>Dimensions: 8 x 10 x 9 m</td>
<td>Dimensions: 2 x 7 x 8 m</td>
</tr>
<tr>
<td>TRL 7-8</td>
<td>TRL 6-7</td>
<td>TRL 5-6</td>
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</tbody>
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2.5.6 INSULATION COORDINATION

A key aspect of system design is the insulation coordination in which the insulation strength of the equipment in a system is chosen as a trade-off with the cost of applying overvoltage protection such as surge arrestors for all conceivable overvoltages (transients) that may occur. To enable the DC connection, the insulation coordination of the Hansa Power Bridge must be compatible with that of the South West Link. Three aspects need to be considered.

Lightning overvoltages – currently, the Hansa Power Bridge is envisaged without overhead lines, and probably with completely enclosed DC switchyards, hence avoiding the impact due to lightning overvoltages. The SouthWest Link does have overhead line sections and is does liable to lightning induced overvoltages, which can travel to the Hansa Power Bridge. This may require additional insulation strength which was not originally foreseen, or additional overvoltage protection measures at Hurva station.
Temporary overvoltages – In case of a pole-earth fault in a symmetrical monopole such as the SWL and the HPB, the voltage on the faulty pole collapses, and that of the healthy pole attempts to rise to 2 pu, as shown by the blue line in Figure 23a). Typically, the overvoltage is limited by surge arrestors to about 1.5 pu. (shown by the green line) to limit the equipment insulation ratings necessary to withstand this overvoltage. This overvoltage lasts until the protection (in this case the AC circuit breakers) clear the fault, after which it decays slowly depending on any shunt resistance in the circuit such as the cable insulation resistance. The exact duration and magnitude of the overvoltage depends on the converter design and is typically vendor specific. Hence the temporary overvoltage characteristics of the Hansa Power Bridge converter must be compatible with the temporary overvoltage rating of the SouthWest Link cable.

Transient interruption voltage – All HVDC circuit breaker technologies rely on inserting a series surge arrester to apply a counter-voltage and absorb the magnetic energy stored in the system. This counter voltage, shown in Figure 23b) and also known as transient interruption voltage (TIV) must be higher than the nominal system voltage, and is typically chosen around 1.5 pu. In case of the application of an HVDC circuit breaker, the breaker TIV must be chosen in such a way that it is compatible with the insulation coordination of the SWL and the HPB in terms of magnitude and the maximum duration of the TIV.

2.5.7 SYSTEM EARTHING

As in AC systems, DC systems need to have a system earth as reference and to avoid excessive line-earth voltages. Typically, a DC system is earthed at one point only, to avoid (DC) earth currents. In a symmetrical monopole configuration, like the SWL and HPB, this earthing is typically realized at the converter station. Several earthing methods exist, as shown in Figure 24a) and are typically converter vendor specific. In addition, in a trade-off between fault current magnitude and overvoltage magnitude during line-earth faults, different earthing impedances can be chosen, as shown in Figure 24b). It is possible to have different earthing impedances at one earthing location, selected by a switch at that location.
The SouthWest Link system earthing is implemented by means of a star-connected earthing (shunt) reactor in between the converter transformers and valves. The starpoint is protected against overvoltages by means of a surge arrester, which can be by-passed by a resistor depending on the system operational configuration and mode. This ability to switch between different earthing impedances enables multi-terminal system operation, in which it can be guaranteed that no more than one earthing point is in operation. The switch should be fast-acting, such that in case of loss of system earthing after grid splitting after a fault, the system earthing can be quickly restored.

The system earthing of the Hansa Power Bridge needs to be compatible with that of the SouthWest Link in order to enable the DC connection. This means that Hansa Power Bridge also must be equipped with a similar earthing impedance arrangement in which the earthing impedance can be switched between a surge arrester or an earthing resistance, to ensure that there is never more than one earthing point in the system. In principle, the choice of earthing location should be open, even though this must be confirmed by more detailed analysis.

2.5.8 APPLICABILITY OF PRESENTED STUDIES AND REQUIREMENTS FOR FUTURE WORK

The presented results are based on models developed in the context of the PROMOTioN project and are configured and parameterised using published information, informed assumptions, experience and typical industrial practice. It is believed that the results presented are accurate to a reasonable level for the purposes of the study – to examine general protection options and trade-offs. It should be clear that the models are not fully representative of the real system and have not used the privileged information that would be required to do the complete studies before implementation of such a scheme. In particular, the following aspects would be important for further examination:

Existing protection schemes within the existing SouthWest Link MMC, in particular the specific arm overcurrent and pole overcurrent limits, any line protection and other relevant protection components where present.

Ideally the correct operation of the control and protection strategies presented would be validated on a detailed manufacturer model or on a control replica system.

2.5.9 DEMONSTRATION

- Demonstration of control and protection strategy via a lab-scale replica of the SWL/HPB
- HVDC CB (lab-scale) provided by KTH
Detailed information on the components of the demonstrator are given in Deliverable 16.7 [6]

2.6 COST BENEFIT ANALYSIS OF THE DC LINK

The goal of the CBA described in this chapter is to prove the value of the proposed solution to the society, as well as to the main involved stakeholders. In contrast to a purely societal CBA of offshore grids, as described in PROMOTioN Deliverable 7.11, this DC link project requires an analysis which would additionally provide estimates of the individual costs and benefits to the relevant stakeholders. This analysis might serve later as a starting point for the consideration of cross-border cost allocation between the involved TSOs.

For the above reasons, focus is on assessing the value to the involved TSOs and society in Sweden and Germany. Some other differences with the framework proposed in Deliverable 7.11 are in the approach for considering different Scenarios and selection of the KPI's.

With regard to the considered project alternatives, the base-case scenario is a status quo, whereby no additional infrastructure is built. In this case, SouthWest Link and Hansa Power Bridge are not connected on the DC side. Further, the analysis will be done for the two configurations of the DC link as presented in section 2.5.1 The following main KPIs will be utilised:

1. Costs associated with the new solution (monetised):
   o CAPEX
   o OPEX

2. Benefits associated with the new solution (monetised):
   o Benefits due to power loss savings.
   o Benefits due to availability gain.
     • Socio-economic welfare change
     • Re-dispatch savings.
As it is shown, the KPIs will be monetised and different alternatives will be compared based on the NPV of the project.

Apart from the monetary impact, the proposed project will most probably have other implications, such as change in the environmental and social impacts, effect on the grid adequacy and stability, and societal well-being. These factors will not be discussed due to the scale of the project and limited scope of the present studies.

In what concerns the evaluation period, end-situation will be considered, with the project build in one go, and for the entire lifetime.

2.6.1 COSTS ASSOCIATED WITH THE NEW SOLUTION

Based on the design configurations proposed above, expenditures associated with the construction and lifetime expenditures of the solution (CAPEX and OPEX) are estimated using the Cost Data Collection report, prepared as a part of Work Package 12. The costs are obtained for the 2 considered Configurations:

- Configuration 1: AC-side protection.
- Configuration 2: DCCB as a primary protection, ACCB as a back-up protection.

Moreover, two different types of DCCBs were analysed:

- Mechanical DCCB, slow – opening time within ~8 ms
- Hybrid DCCB – opening time within ~2 ms

The summary of added costs during entire lifetime of the asset is presented in Table 4. Costs associated with the new solution. For this calculation a lifetime of 25 years and discount factor of 4% were assumed as recommended by ENTSOE framework for CBA [7].

<table>
<thead>
<tr>
<th>Costs associated with the new technological solution EURmIn</th>
<th>ACCB protection</th>
<th>DCCB primary, AC back-up</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Mechanical DCCB</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Investment Costs</td>
<td>€</td>
<td>€</td>
</tr>
<tr>
<td>Total Operating Costs</td>
<td>€</td>
<td>€</td>
</tr>
<tr>
<td><strong>Total Costs</strong></td>
<td>€</td>
<td>€</td>
</tr>
<tr>
<td><strong>Hybrid DCCB</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Investment Costs</td>
<td>€</td>
<td>€</td>
</tr>
<tr>
<td>Total Operating Costs</td>
<td>€</td>
<td>€</td>
</tr>
<tr>
<td><strong>Total Costs</strong></td>
<td>€</td>
<td>€</td>
</tr>
</tbody>
</table>

For this analysis we have included the costs associated with DCCBs and high-speed switches, DC reactors, DC cables, control systems and land rental cost in Sweden. The 10% contingency was assumed for the cost of any auxiliary protection and monitoring systems, additional measurement equipment and master control system in line with the outcomes of protection systems CBA by PROMOTioN WP4. It is included in the Total Investment Costs.
As for cost of VARC DCCB, it is worth to mention that promoters expect it to be on par with mechanical DDCBs cost-wise. However, seeing this uncertainty, it was not included in the analysis.

Seeing that DCCB contributes to the larger part of investment costs, the difference between total costs for different configurations and types of a breaker can be significant. In principle, both of the proposed configurations can be integrated in the system. From the analysis presented in section 2.5 it stems that both hybrid and mechanical DCCB, if complemented with a reactor of a corresponding size, can provide the required protection functionality and clear anticipated faults. Therefore, a choice of specific configuration or DCCB type is left to the developer who may favour one or another option depending on the availability of finance or other considerations. From the point of view of technological innovation and progressing protection systems it might be more attractive to have a more complex, hybrid DCCB installed.

2.6.2 BENEFITS DUE TO POWER LOSS SAVINGS

When connecting the new DC link in Hurva, one of the main benefits is the power loss savings made by bypassing two HVDC converters. To estimate these power savings and resulting economic benefit, assumptions must be made about the converter losses, the intended use of the DC interconnection as well as the operation of the bypassed converters.

2.6.2.1 CONVERTER LOSSES

For the calculation of the power savings, the converter losses as a function of the transferred power should be calculated. As a first assumption the losses were measured using the converter model from PROMOTioN WP2, the input power and output power were measured at different operating conditions and the losses were calculated as the difference between these values. The resulting losses are shown in Figure 26, where also the common estimate of 1 % losses are shown.
From the simulations the losses are significantly higher than 1% losses of the transferred power and should therefore be adjusted. The difference can be due to the accuracy of the measurements, the losses are calculated as a small difference between two large numbers. The losses for both the sending end converter and the receiving end converter are adjusted with a constant so the losses at rated power is 1% and a polynomial is fitted to these curves, see Figure 27.

Here, the yellow curve is the loss estimation that is used for the further calculations, where the power losses $P_{loss}$ are calculated as a function of the transferred power for the converter $P_{conv}$.

$$P_{loss} = 2.01 + 0.0008 \times P_{conv} + 0.00001 \times P_{conv}^2$$

Note that the same loss calculations are made for the South West Link converters as well as for the Hansa Power Bridge converters.

**2.6.2.2 POSSIBLE OPERATING SCENARIOS**

For calculation of the loss savings, the power transmitted in the new DC connection must be estimated and the operation of the two bypassed converters in Hurva must be known.

The situation when the new connection is most likely to be used is when transmitting power from Sweden to Germany. Since most of the generation in Sweden is located in the north and loads are mainly located in the south, the energy transmitted to Germany using Hansa Power Bridge is preferably taken from the SouthWest Link, enabling the use of the new DC connection. If power is transferred from Germany to Sweden with Hansa Power Bridge it will most likely be needed in the south of Sweden and not be transmitted further by the SouthWest Link, whereby the added connection is not used. Therefore, it is assumed that when transmitting power from Sweden to Germany, it will be made using the added connection.
Four different scenarios are used when calculating the transmitted power in the new connection between the SouthWest Link and Hansa Power Bridge. Note that it is assumed that the connection is only used for power transmission from Sweden to Germany based on the present trend of lower electricity prices in Nordics.

- **Scenario 1**: Full usage of the links from Barkeryd to Güstrow, 600 MW. This is not a realistic case but used for a benchmark.
- **Scenario 2**: Based on the usage of Baltic cable during 2018. When Baltic cable is running at full capacity, HPB will also run at full capacity. When Baltic cable is running at lower power, the transmitted power for Baltic cable is divided equally to HPB and Baltic cable. All power for HPB is supplied from SWL.
- **Scenario 3**: Looking at future predictions for HPB, assume full export during peak hours when wind is less than 7 m/s.
- **Scenario 4**: Full export/import based on price differences 2018.

When bypassing the converters in Hurva, there are three different options for their operation.

- **Option 1**: Both converters in Hurva are in operation also when the DC connection is used but the active power flow is set to zero.
- **Option 2**: One converter in Hurva is in operation also when the DC connection is used but the active power flow is set to zero.
- **Option 3**: None of the bypassed converters in Hurva is in operation when the DC connection is used.

### 2.6.2.3 LOSS SAVINGS FOR SCENARIO 1

For scenario 1, it is assumed that there is a constant power flow of 600 MW in the new DC connection. The losses are calculated using the equation below, resulting in 6.1 MW losses for rated power of 600 MW, and 2 MW losses for a converter with no active power transfer.

\[
P_{loss} = 2.01 + 0.0008 \times P_{conv} + 0.00001 \times P_{conv}^2
\]

Using the number of hours for one year 24*365=8760 h, the losses for the different options for the bypassed converters can be obtained, as shown in Table 5.

<table>
<thead>
<tr>
<th></th>
<th>Option 1</th>
<th>Option 2</th>
<th>Option 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>(P_{loss}) in Hurva no DC link</td>
<td>(2<em>6.1)MW</em>8760 h = 107 GWh</td>
<td>(2<em>6.1)MW</em>8760 h = 107 GWh</td>
<td>(2<em>6.1)MW</em>8760 h = 107 GWh</td>
</tr>
<tr>
<td>(P_{loss}) in Hurva with DC link</td>
<td>(2<em>2.01)MW</em>8760 h = 35 GWh</td>
<td>(1<em>2.01)MW</em>8760 h = 18 GWh</td>
<td>0</td>
</tr>
<tr>
<td>Loss gain</td>
<td>107-35=72 GWh</td>
<td>107-18=89 GWh</td>
<td>107 GWh</td>
</tr>
</tbody>
</table>
2.6.2.4 LOSS SAVINGS FOR SCENARIO 2

For Scenario 2, the transmission of power is based on the usage of Baltic Cable 2018. It is assumed that when Baltic cable is running at full capacity, Hansa Power Bridge will also run at full capacity. When Baltic cable is running at lower power, the transmitted power for Baltic cable is divided equally between Hansa Power Bridge and Baltic cable. It is assumed that full power is 600 MW transferred between the SouthWest Link and Hansa Power Bridge. Note that Baltic cable was out of service for about 2 months during 2018.

An example of the calculated transmitted power in the new connection for Scenario 2 compared to the power for Baltic Cable is shown in Figure 28.

![Figure 28 – Power in the DC connection for scenario 2 compared to the power for Baltic Cable.](image)

The calculated losses and loss savings for Scenario 2 are shown in Table 6.

<table>
<thead>
<tr>
<th></th>
<th>Option 1</th>
<th>Option 2</th>
<th>Option 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>$P_{\text{loss}}$ in Hurva no DC link</td>
<td>30 GWh</td>
<td>30 GWh</td>
<td>30 GWh</td>
</tr>
<tr>
<td>$P_{\text{loss}}$ in Hurva with DC link</td>
<td>19 GWh</td>
<td>9 GWh</td>
<td>0</td>
</tr>
<tr>
<td>Loss gain</td>
<td>30-19=11 GWh</td>
<td>30-9=21 GWh</td>
<td>30 GWh</td>
</tr>
</tbody>
</table>

2.6.2.5 LOSS SAVINGS FOR SCENARIO 3

For Scenario 3, the future prediction for Hansa Power Bridge is used, where full transmission from Sweden to Germany is assumed during peak hours (9-20) when wind speed is less than 7 m/s. This is based on the statement provided by the project developers towards ENTSOE from the TYNDP project (available at [https://tyndp.entsoe.eu](https://tyndp.entsoe.eu)): 

“The increase of renewable power in Sweden and Germany will lead to an increased need for trade in situations with high surplus due to high wind power production. Flows are expected to be balanced on an annual level with southbound flow during peak hours and when the hydro inflow in Sweden are high and northbound in periods of high RES generation in Germany and during nights.”

The wind data for the North of Germany that was used in this analysis is taken from the open sources, available at “https://opendata.dwd.de/climate_environment/CDC/observations_germany/climate/hourly/wind/historical/” and is shown in Figure 29.

![Wind data used in scenario 3.](image)

Figure 29 – Wind data used in scenario 3.

An example of the calculated transmitted power in the DC connection for Scenario 3 compared to the wind speed is shown in Figure 30.
The calculated losses and loss savings for Scenario 3 are shown in Table 7.

Table 7 Calculated loss savings for scenario 3.

<table>
<thead>
<tr>
<th></th>
<th>Option 1</th>
<th>Option 2</th>
<th>Option 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>$P_{\text{loss}}$ in Hurva no DC link</td>
<td>43 GWh</td>
<td>43 GWh</td>
<td>43 GWh</td>
</tr>
<tr>
<td>$P_{\text{loss}}$ in Hurva with DC link</td>
<td>14 GWh</td>
<td>7 GWh</td>
<td>0</td>
</tr>
<tr>
<td>Loss gain</td>
<td>43-14=29 GWh</td>
<td>43-7=36 GWh</td>
<td>43 GWh</td>
</tr>
</tbody>
</table>

### 2.6.2.6 LOSS SAVINGS FOR SCENARIO 4

For Scenario 4, the power flow in Baltic Cable is based on the price differences between South Sweden and Germany in 2018, where full power flow (600 MW) is assumed and the direction is based on the price difference. An example of a comparison between the difference in spot prize and the power in Baltic Cable for 2018 is shown in Figure 31.
An example of the calculated transmitted power in the DC connection for Scenario 4 compared to the difference in spot price is shown in Figure 32.

The calculated losses and loss savings for Scenario 4 are shown in Table 8.

<table>
<thead>
<tr>
<th></th>
<th>Option 1</th>
<th>Option 2</th>
<th>Option 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ploss in Hurva no DC link</td>
<td>65 GWh</td>
<td>65 GWh</td>
<td>65 GWh</td>
</tr>
</tbody>
</table>
2.6.2.7  SUMMARY OF THE LOSS SAVINGS

A summary of the annual loss savings for all scenarios is shown in Table 9.

<table>
<thead>
<tr>
<th>Scenarios</th>
<th>Option 1: 2 conv at DC link</th>
<th>Option 2: 1 conv at DC link</th>
<th>Option 3: 0 conv at DC link</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scenario 1</td>
<td>72 GWh</td>
<td>89 GWh</td>
<td>107 GWh</td>
</tr>
<tr>
<td>Scenario 2</td>
<td>19 GWh</td>
<td>21 GWh</td>
<td>30 GWh</td>
</tr>
<tr>
<td>Scenario 3</td>
<td>29 GWh</td>
<td>36 GWh</td>
<td>43 GWh</td>
</tr>
<tr>
<td>Scenario 4</td>
<td>43 GWh</td>
<td>54 GWh</td>
<td>65 GWh</td>
</tr>
</tbody>
</table>

The costs for power losses are normally monetized at the price of the exporting zone and split equally among the TSOs operating an interconnector. For the monetization of losses, we assume a constant annual average power price through the lifetime. It is set equal to 50 EUR/MWh, that is a current average price in the exporting Swedish bidding zone SE4. At a discount rate of 4% and lifetime of 25 years this will lead to the following lifetime savings, shown in Table 10.

<table>
<thead>
<tr>
<th>Benefits due to Power Loss Savings (EURmln) over 25 years</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Scenario 1</strong></td>
</tr>
<tr>
<td><strong>Option 1</strong></td>
</tr>
<tr>
<td><strong>Option 2</strong></td>
</tr>
<tr>
<td><strong>Option 3</strong></td>
</tr>
</tbody>
</table>

These values change linearly depending on the assumed average annual power price. Based on the DNV GL internal power price outlooks, the assumption of 50 EUR/MWh is a realistic indication of future price evolution. It can be seen that the difference in potential gains between Scenarios is significant. Excluding a purely academic base-case Scenario 1, a potential outcome can differ by a factor of more than two, e.g. when considering Scenario 2 and 4. Thus, it is important to realise which of these Scenarios and converter usage Options is more plausible. It is our belief that Scenario 4 – full usage according to the price differentials between South Sweden and Germany, is the most realistic. The reason is that market prices already take into account presence of Baltic Cable and reflect residual differences in the local markets’ clearing points, which will justify further energy trading between two countries.

2.6.3  COSTS DUE TO DC LOSSES IN INDUCTOR

As it was pointed out in 2.5.3.1, for each DCCB topology, an appropriately sized inductor has been chosen such that the SWL converters do not block following a DC fault on the HPB. This inductor will result in additional power losses when transferring power via DC connection. Hence, we quantify these losses to evaluate their significance on the business case.
To quantify these losses, we consider operational Scenario 4, as defined in 2.6.2.6. In this scenario connection is operated at a full capacity of 600 MW whenever there is a positive price difference between Germany and Southern Sweden. These losses are then monetised at a power price of 50 EUR/MWh in line with the earlier quantification of benefits. Further we assume the following DC losses in inductor based on the values indicated by experts within PROMOTioN:

- 1.25 kWh for each MWh transferred in 900 mH inductor (Mechanical DCCB)
- 0.347 kWh for each MWh transferred in 250 mH inductor (Hybrid DCCB)

Below, is a summary of additional monetary costs due to inductor losses.

<table>
<thead>
<tr>
<th>DC inductor losses</th>
<th>250 mH</th>
<th>900 mH</th>
</tr>
</thead>
<tbody>
<tr>
<td>Annual costs</td>
<td>€ 0.15</td>
<td>€ 0.04</td>
</tr>
<tr>
<td>Lifetime value (NPV)</td>
<td>€ 2.32</td>
<td>€ 0.64</td>
</tr>
</tbody>
</table>

2.6.4 BENEFITS DUE TO AVAILABILITY GAIN. SOCIO-ECONOMIC WELFARE INCREASE.

Improvement in availability of the DC corridor for the North to South power flow is achieved by replacing two series connected converters with DCCB. This is shown in reliability block diagram in Figure 33.

This diagram only presents the link configuration with a single DCCB. The other configuration did not yield noticeable difference in the resulting availability figures and are not presented here.

Three operation modes are possible:

- Transfer of 700 MW – e.g. one of Hurva SWL converters is under outage or Hurva HPB converter is under outage; power is transferred via added DC connection.
- Transfer of 600 MW – e.g. outage of any of SWL links, including converter or cable; power is transferred via added DC connection.
- Transfer of 0 MW – e.g. outage of any component in HPB.

As a result of analysis, the annual number of hours when a certain capacity is available is calculated. Results are presented in Figure 34.

It can be seen that the number of full capacity hours, i.e. 700 MW, would not change would the new link be constructed. On the other hand, number of no capacity hours is reduced and offset by extra 12 hours when 600 MW are available for transfer.

The benefits due to increased availability can be divided in the benefits due to increased utilisation of the link, but also due to a lower chance of sudden capacity loss. The former can be presented in terms of extra delivered energy or extra number of hours in a year when the link is available for power transfer. The latter might be estimated as the reduction in payments that TSO would have to perform to procure energy from the local balancing markets to compensate for a sudden loss of the interconnector.

### 2.6.4.1 INCREASE IN SOCIO-ECONOMIC WELFARE

Increased utilisation of the link will lead to increased utilisation of HPB interconnector, and subsequently increase in the Socio-Economic Welfare in the connected countries. HPB project promoters have reported on the TYNDP webpage that the annual SEW due to HPB utilisation amounts to 47.8 EURmln\(^1\) [8]. Assuming that this gain is uniformly spread across all hours of a year, it can be calculated how much is gained during one hour – 5.5 kEUR. Multiplying this number by the extra 12 hours gained due to DC link we obtain the annual gain in SEW to be equal to 65.4 kEUR. Throughout the lifetime of 25 years and at a discount rate of 4%, the NPV will amount to approximately 1.02 EURmln. These calculations are summarised in Table 12 below:

<table>
<thead>
<tr>
<th>SEW benefits from the increased availability (EURmln)</th>
</tr>
</thead>
</table>

\(^1\) This is an average of four scenarios reported on ENTSO-E website
2.6.4.2 INCREASE IN GRID REDUNDANCY AND SECURITY OF SUPPLY

The other benefits of increased availability are related to a reduced risk of outages and/or sudden loss of transmission capacity. In case a fault happens in converters or AC busbar at Hurva substation, it would be possible to continue power transfer via the new DC link. This can potentially lead to a reduction of associated costs/economic losses, such as:

- contracting less spinning reserves or decreasing temporary overload transfer capacity of any parallel AC paths – direct costs experienced by TSO
- loss of load – theoretical socio-economic losses
- procuring extra power at the balancing market / redispatch – direct costs experienced by TSO

Seeing that change in availability is very modest, it is arguable whether TSOs will consider reducing precautionary measures, such as contracting less spinning reserves. Their size is dictated by the overall configuration of the power system of a country and is not affected by extra availability of an interconnector.

Furthermore, it can be argued that the DC link could contribute to the reduction of the Energy Not Served (ENS) in South Sweden or Germany. However, due to the fact that transfer capacity is only 700 MW, it is not expected that an outage of HPB would lead to energy not served. Reference incident for Nordic system is 1800 MW, and 3000 MW for Continental Europe. Hence, a sudden loss of the HPB interconnector should not lead to any severe impacts. It can be argued that with the decommission of nuclear power plants in Ringhals and Oskarshamn (Sweden), the picture may change and the link could significantly contribute to reliable electricity supply in the southern regions of Sweden providing extra hours of connection to the continent [9]. Nevertheless, these factors are not fully certain for the moment, and can only be quantified via extensive scenario modelling. From a heuristic point of view, it is concluded that the increase in availability will have minor effect on the socio-economic losses related to the ENS, and will not be monetised.

Finally, a sudden loss of an interconnector will lead to frequency deviations, and TSO might have to procure additional energy at the balancing market or even initiate redispatch actions. Based on the discussions with three TSOs, it is 100 EUR/MWh is a good assumption for the cost of such remedial actions. This yields approximately 11 EUR/Min of lifetime savings, as shown in Figure 17. Such expenses are usually passed to the grid users and reflected in transmission charges, which in this case could be reduced, yielding positive socio-economic impact.

Table 13 Re-dispatch savings from the increased availability

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Extra hours of availability [hrs]</td>
<td>12</td>
</tr>
<tr>
<td>Capacity available [MW]</td>
<td>600</td>
</tr>
<tr>
<td>Re-dispatch cost [EUR/MWh]</td>
<td>€ 100.00</td>
</tr>
<tr>
<td>Annual savings [EUR/Min]</td>
<td>€ 0.7</td>
</tr>
</tbody>
</table>
2.6.5 SUMMARY OF THE COSTS AND BENEFITS.

The total of costs and benefits of the proposed DC connection modification are summarised in Table 14, where negative values are given in brackets. Note that entries 4 to 6 apply to both types of DCCB.

<table>
<thead>
<tr>
<th>Cost / Benefit Element</th>
<th>Mechanical DCCB</th>
<th>Hybrid DCCB</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 CAPEX</td>
<td>€ (14.69)</td>
<td>€ (43.22)</td>
</tr>
<tr>
<td>2 OPEX</td>
<td>€ (2.06)</td>
<td>€ (14.68)</td>
</tr>
<tr>
<td>3 DC Reactor losses</td>
<td>€ (2.32)</td>
<td>€ (0.64)</td>
</tr>
<tr>
<td>4 Power loss savings</td>
<td>€ 42.18</td>
<td></td>
</tr>
<tr>
<td>5 SEW gain</td>
<td>€ 1.02</td>
<td></td>
</tr>
<tr>
<td>6 Re-dispatch savings</td>
<td>€ 11.25</td>
<td></td>
</tr>
<tr>
<td>7 Total Lifetime Project Value (NPV)</td>
<td>€ 35.38</td>
<td>€ (4.09)</td>
</tr>
</tbody>
</table>

Note that CAPEX and OPEX values are given for the configuration with a single DCCB only, thus DCCB is used as primary protection, and AC side breakers as a secondary one. For the other cases please refer to Table 4 Costs associated with the new solution. Power loss savings are given for the average value of Scenario 4, as discussed in 2.6.2.

It can be seen that the project proves to have a net positive value when 8ms DCCBs are used. Due to a substantially higher cost, Hybrid DCCBs result in a negative value over entire lifetime. Despite the high NPV of the configuration with Mechanical DCCB, TSOs are likely to consider overall risks too high and might require additional support as discussed further.

2.7 FINANCING

2.7.1 PROJECT OF COMMON INTEREST STATUS AND CONNECTING EUROPE FACILITY SUPPORT

In order to further de-risk the project, it is possible to apply for the financial assistance for instance as a Project of Common Interest (PCI). PCIs are eligible for funding from the Connecting Europe Facility (CEF), a key EU funding instrument for targeted infrastructure investment at European level. This funding may be in the form of grants, (low-cost) finance or investment credits, or a combination of these. In addition to grants, the CEF offers financial support to projects through innovative financial instruments such as guarantees and project bonds. These instruments create significant leverage in their use of EU budget and act to attract further funding from the private sector. The use of financial instruments under the CEF encompasses the CEF debt instrument and the CEF equity instrument. The CEF Debt Instrument was launched in 2015 jointly by the European Commission and the European Investment Bank (EIB), and is currently implemented by the EIB. The Equity Instrument, currently under
development, aims at providing equity or quasi-equity financing to smaller and riskier projects in the field of broadband, transport, and energy [10].

CEF is operated by the INEA, The Innovation and Networks Agency. The SWL-HPB link project underpins their longer term goals for innovation in energy, transport and telecoms infrastructure. The CEF structures finance as a grant to cover specific costs (the concept agreement specifically says that it will not fund "lump sum" projects. This may limit the finance in some turnkey cases). However, it should be possible to separate specific costs and tasks in order to reach EU standards. The CEF will pre-finance projects if necessary, albeit purchased assets, if not later utilised, will revert to EC ownership.

To qualify for PCI status, a project needs to be in TYNDP. The Hansa Power Bridge (1 and 2) are both in TYNPD 2018. Neither the Hansa Power Bridge nor the SWL are currently on the map of PCIs. The Hansa Power Bridge might qualify in its own right. The combination should certainly qualify due to its innovative nature. Also, it may be possible to position the proposed project as a "technical design of the planned infrastructure".

Projects are selected as PCIs based on five criteria. They must:
- have a significant impact on at least two EU countries
- enhance market integration and contribute to the integration of EU countries' networks
- increase competition on energy markets by offering alternatives to consumers
- enhance security of supply
- contribute to the EU's energy and climate goals.

The proposed DC connection seems to satisfy the above criteria. Further requirement is that projects should facilitate integration of increasing share of energy from variable renewable energy sources. The selection process gives preference to projects in priority corridors, as identified in the Trans-European Networks for Energy (TEN-E) strategy.

The four infrastructure corridors identified as priority by the TEN-E require urgent infrastructure development in electricity in order to connect regions currently isolated from European energy markets, strengthen existing cross-border interconnections, and help integrate renewable energy. For each of these priority corridors, a dedicated Regional Group has been established to propose and review candidate projects of common interest, which contribute the most to achieving EU's energy and climate policy objective by modernising the existing grid. Two of these may be relevant to this project:

- **North Seas offshore grid ('NSOG')**
  Integrated offshore electricity grid development and related interconnectors in the North Sea, Irish Sea, English Channel, Baltic Sea and neighbouring waters to transport electricity from renewable offshore energy sources to centers of consumption and storage and to increase cross-border electricity exchange.

- **Baltic Energy Market Interconnection Plan in electricity ('BEMIP Electricity')**
  Interconnections between Member States in the Baltic region and the strengthening of internal grid infrastructure, to end the energy isolation of the Baltic States and to foster market integration; this includes working towards the integration of renewable energy in the region.
Candidate projects are proposed by their promoters. They are then assessed by Regional Groups that include representatives from EU countries, the Commission, transmission system operators and their European networks, project promoters, regulatory authorities, as well as the Agency for the Cooperation of Energy Regulators (ACER). ACER is responsible for assessing electricity and gas projects' compliance with the PCI criteria and their European added value. The Commission is solely responsible for the appraisal of projects linked to oil supply connections in central and eastern Europe and cross-border carbon dioxide networks.

After these assessments, the Commission adopts the list of approved PCIs via a delegated act procedure. The list of projects is then submitted by the Commission to the European Parliament and Council. These institutions have two months to oppose the list, or they may ask for an extension of two months to finalise their position. If neither the Parliament nor the Council rejects the list, it enters into force. The Parliament and the Council cannot request amendments to the list [11].

### 2.7.2 SYNERGIES BETWEEN HORIZON 2020 AND CEF

Interestingly, Innovation and networks Executive Agency (INEA) fosters synergies between Horizon 2020 (H2020) projects and CEF. There is a natural link between the two, since the former is aimed at research and the latter at deployment. In other word, EU-funded research project under H2020, such as PROMOTioN, can benefit from the further support, provided that the technology has been sufficiently progressed and became ready for an industrial scale deployment.

In case of SWL-HPB DC link, construction of such a small-scale multi-terminal connection is a logical continuation and one of the first steps proposed in the Deployment Plan delivered by WP12. Albeit PROMOTioN looks far in the future up to 2050, the foundation for the deployment of meshed HVDC grid must be laid in the near-term if the desired scale of offshore wind development is to be achieved. Hence the main stakeholders involved in the project would be able to apply for the financial support from EU. Website of INEA clearly states that parties who have received H2020 energy funding and obtained significant results might be ready to apply to CEF Energy calls [12].

### 2.7.3 ESTIMATION OF FINANCIAL GRANT

According to a EU Regulation 1316/2013 addressing the principles for the allocation of financial support by the EU, the cost of equipment treated as a capital expenditure may be eligible up to its entirety. However, this should not include land costs, that is why the values under Total Investment Costs are different in the Table 15 from Table 4. The funding rates for the overall project cost may reach 75% at maximum for projects that provide an evidence of their contribution to the Union-wide security of supply or comprise highly innovative solutions. [13]

For simplicity of the grant value estimation, a simple interest-free loan is assumed and the net present value of payback over the lifetime of the project is used to calculate a potential “relief” in the costs of installing untested technology, excluding land cost. The resulting values of the funding for each possible configuration and type of DCCB is given in Table 15 Potential contribution of EU grant.

<table>
<thead>
<tr>
<th>Grant / Contribution from CEF funding (EURmln)</th>
<th>ACCB protection</th>
<th>DCCB primary, AC back-up</th>
</tr>
</thead>
<tbody>
<tr>
<td>Table 15 Potential contribution of EU grant</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
2.7.4 OTHER FINANCING OPTIONS

Other options for obtaining financial support for the deployment of electricity infrastructure are also possible as presented in Figure 35 Electricity Infrastructure Financing Options. These will not be reviewed in the current document.

Within the scope of this project we have not investigated national R&D and technology funding schemes. Local subsidy expertise may provide support for this.
2.8 LEGAL, REGULATORY AND COMMERCIAL BARRIERS MITIGATION

2.8.1 OVERVIEW OF LEGAL, REGULATORY AND COMMERCIAL ISSUES

There are multiple legal, regulatory and commercial barriers which may hinder the construction of the new DC link. Although being technically feasible, the link needs to fit into existing regulatory arrangements and commercial practices. Based on the conducted consultations, it was concluded that if not addressed properly, these aspects can undermine realization of the project. A list of the related barriers with explanation is given below:

- **Legal status.**
  Hansa Power Bridge will be covered by TSO agreements for the transfer of power and ownership of assets as a regulated interconnector.
  a. What will be the status of the DC link? Regulated asset or interconnector extension?
  b. Can it influence the status of the SWL and the sub-station in Hurva?

- **Ownership.**
  The DC link would be fully located within the territory of Sweden.
  a. Are there any important aspects related to ownership by Swedish TSO that need to be considered?

- **Operation and maintenance responsibility.**
  a. Is there a need for a bilateral agreement between two TSOs on the operational rules?
  b. How can this fit with the operational responsibility that is envisaged for HPB?
  c. Link failure responsibility.

- **Operation strategy, market arrangement.**
  a. How would the link be controlled marketwise?
  b. What are the requirements on availability of the link to the market?

- **Revenue scheme, business model. Cross-border cost allocation.**
  With the construction of interconnectors, their costs are normally split equally between the involved TSOs. These are development costs and enduring operational costs. Looking at the benefits side, the avoided cost of energy losses and increased social welfare due to the extra availability of connection from Sweden to Germany must be accounted for.
  a. What will be the cost allocation for the construction of DC link, seeing that it does not physically cross the border between two countries, but contributes to the socio-economic welfare in both?
  b. Should these costs and revenue be incorporated into existing business case of HPB?

- **Procurement.**
  It is expected that the HV equipment for HPB and SWL link will come from different vendors. This may result into certain interoperability-related issues when connecting two HVDC cables on the DC side.
  a. What are these interoperability issues?
  b. How can the interfaces between different components be managed, who carries the liability?
  c. How will the link affect existing contracts between the TSOs and manufacturers of equipment for HPB and SWL?

The above-identified issues are closely intertwined and as such need to be addressed together. The legal status of the link is interdependent with its ownership and governance. Involved parties will sign a project agreement, which normally covers ownership and maintenance responsibility. Cost of construction incurred by owner(s) will
have to be offset by revenues, which are determined by income regulation and selected business model. These models will include certain operational rules, which must be designed based on the existing EU regulations and agreed market arrangement. In its turn, market arrangement is affected by a legal status and governance over the link.

The primary goal of this section is to propose a solution for the above issues, which would keep the business case of the link financially attractive, fit within the existing regulatory frameworks and be easy to implement. Due to the fact that the ultimate purpose of building the proposed link is its expected positive effect on the socio-economic welfare (SEW) of the involved Member States, it was decided that the added societal benefits from the link should be taken as a starting point for the discussion as shown in Figure 36. In parallel, a legal status of the link will have implications on the applicable market arrangement and operational aspects. The remaining independent aspect is related to procurement and interoperability of equipment.

As a universal measure to facilitate the mitigation of these barriers, a strong engagement of public stakeholders, such as relevant authorities, ENTSOE, etc. is recommended. The formalisation of commitment in the form of a project-specific agreement is an expression of the willingness of the stakeholders to support the development. In early project stages, it provides additional certainty for project developers and creates a framework for the communication with relevant governmental bodies. SvK and 50 Hertz should assume the responsibility, as well as respective regulators in both countries, and the EC [14].

2.8.2 LEGAL STATUS

One of the major questions to be addressed is a legal status of the DC connection. From the jurisdiction point of view, Sweden has a full governance over the connection due to its geographical location. Nevertheless, there are still uncertainties with regard to the classification of such an asset.

At the moment, SWL cable is a part of SvK TSO Regulatory Asset Base (RAB). Oppositely, HPB is envisaged to be a cross-border asset, i.e. regulated interconnector. With the addition of the DC link, which physically connects two different types of assets, two issues arise:

- What will be the status of the DC link itself?
- Does it affect the existing status of SWL and/or HPB?

There are two options available with regard to the status of the link itself – it can be treated as a part of the SvK’s RAB (i.e. Swedish transmission line), or it can become a part of the existing arrangement for HPB.

Several considerations advocate for moving the governance over the link, and subsequently its legal status, as much towards SvK as possible. First of all, the link will affect flows in the connected DC cables. SvK is, obviously, the only involved party which has physical access to both of them. Furthermore, the link is fully located within the national borders of Sweden. If it is treated as a separate asset, it should be regulated by a national TSO. Finally,
size of the link and number of needed components is modest, which makes it more attractive to be owned and managed by a single party.

On the other hand, the consequences of new DC link presence will affect Germany and Sweden equally. The social welfare is expected to increase because the link will reduce losses and improve availability of the corridor between the Sweden and Germany. One could argue that both parties need to be involved in the project, and treating the connection as a part of the HPB could become a solution. Defining the link as an extension of HPB might ease the process of necessary inter-TSO agreements regarding the operation strategy and cost allocation. It is worth to mention that the link cannot be treated as an independent interconnector. According to the EU Regulation 2019/943 [15], an interconnector is a transmission line which crosses or spans a border between Member States and which connects the national transmission systems of the Member State. HPB interconnector is currently in the permitting stage. Due to the fact that the realization of HPB has already commenced and certain decisions have been taken not accounting for the proposed extra DC link, it is not realistic to expect that it would be included in the HPB project at this stage.

As a result, it is recommended that the link has to be treated as a separate regulated asset under the Swedish TSO asset base. In the planning process, however, both Swedish and German TSOs should cooperate closely to agree on the main aspects in which the link can affect operation of HPB cable. Due to the fact that the project is innovative and unique in its nature, having two TSOs cooperating closely would result in additional gains from extensive experience. At the same time, construction, ownership and O&M would remain within SvK scope of responsibility. In this case, the new connection can be seen as a part of SvK grid, analogically to already existing AC connections between the two DC cables. This will have certain implication on the required availability of this link, discussed further under Operational Rules and Responsibility.

2.8.3 DEVELOPMENT AND OWNERSHIP

As concluded in the previous section, the full ownership over the asset should belong to the Swedish TSO. HPB is planned to be a regulated interconnector, whereby the full ownership over the Hurva substation remains under SvK, and subsequently all underlying assets as well. Analysing responsibility for the development and construction of the asset, it is logical to assume the same, as it stems from the ownership rights. By law, SvK is responsible for the construction and development of its own grid assets. There is no uncertainty in this regard and development responsibility is not a barrier as such. Nevertheless, due to the unique nature of the new connection it could be beneficial to have an alignment between the involved stakeholders.

Clearly, involvement of German TSO is not required by law but could bring additional expertise, optimize the process of construction and facilitate a more transparent procurement. The latter one can become crucial seeing that the components for two DC cables and proposed link may all be supplied by different manufacturers. It will be discussed further in detail. Moreover, cooperation between the TSOs will also extend the learning curve for building this type of links to both TSOs.

In order to formalize such collaboration, a project-specific agreement between TSOs can be concluded. This is driven by a need of alignment between two involved parties to ensure the most efficient and mutually optimal implementation of DC link. It is recommended that the development role remains with SvK, while 50 Hertz can be involved in monitoring, quality control and advisory during the process.
2.8.4 OPERATIONAL RULES AND RESPONSIBILITY

As a TSO, SvK will assume the full responsibility for the operation and maintenance of the asset, which is part of its RAB. Maintenance of the DC link can be done without interrupting the flows in HPB, since the DC link can be disconnected by means of switches, and connected back once the maintenance has finished. This adds a lot of flexibility for planning the maintenance of not only the link itself, but also SWL or HPB equipment located at Hurva substation. For the maintenance of HPB equipment, mutual agreements between two TSOs will be in place and planning will be done in advance. Due to additional redundancy provided by the link, cross-border power flows often would not have to be interrupted. Involvement of 50 Hertz is not needed for DC link maintenance, however SvK should keep its counterparty informed when such maintenance is planned.

A similar recommendation is given with regards to the operation. The full responsibility for the control will lie on SvK but 50 Hertz should be aware of the main operational principles. These principles, however, will not differ from the commonly used rules. The link should be made available to the market, and flows in the link will be determined by non-discriminating market clearing algorithms. Seeing that the link reduces the losses for the North-South flows, SvK should aim at utilizing the asset as much as possible, provided that system security and limits are not hindered.

For HPB, Article 16 of EU Regulation 2019/943 prescribes that 70% of interconnector capacity and adjacent network have to be made available to the market respecting operational security limits for internal and cross-zonal network elements [15]. It is important to take this into account for the control and flow management of the new link. Further, operational rules should follow European CACM, FCA, Operation, Electricity Balancing and other relevant Network Codes which describe market rules for the allocation of grid capacity, as it would be done for any other grid asset.

2.8.5 BENEFITS DISTRIBUTION

As it was shown in the Chapter 2.6, the lifetime savings due to the connection of new DC link will benefit both Sweden and Germany. The proposed link has two main positive contributions:

- It allows to reduce energy losses for the power flows which are expected to be predominant – from mid-Sweden to the south via SWL cable, and then to Germany via HPB interconnector. The losses are reduced due to the avoided need of conversion from DC to AC and back to DC between the two cables.
- It improves availability of HPB interconnector at the time when the SWL or HPB converters are out of order.

Regardless from the direction of power flows, both TSOs will benefit from not paying for the avoided power losses, as normally these costs are split equally. The other positive effect – increased link availability, has an additional minor contribution to the socio-economic welfare in both. The contribution to the SEW as a result of higher utilization is negligible compared to the avoided cost of losses, and therefore should not be taken into account. The contribution to the security of supply is also minor since the availability of the transfer capacity from mid-Sweden to Germany is only increased by 12 hours in a year. With or without the link, the Swedish TSO would have to procure capacity reserves in approximately equal amount, since the risk of outage is not changed significantly.
Consequently, according to the conducted CBA, the distribution of the benefits is almost equal between the involved TSOs and respecting Member States.

2.8.6 CROSS-BORDER COST ALLOCATION

Each transmission system reinforcement has implications on the individual benefits and losses of the concerned parties. When a certain country is affected differently from another, compensation via Cross-Border Cost Allocation (CBCA) should take place [16].

In line with the CBCA recommendations issued by ACER, it is recommended to take the distribution of net positive effect as a base for determining the proportion in which the initial investment and operation cost for the link have to be allocated across the countries [17]. Following the Cross-Border Cost Allocation methodology proposed in PROMOTiOn deliverable D7.4, the principle of “beneficiary pays” should be applied, with the benefits assessed based on the results of conducted project CBA. Consequently, the Swedish and German TSO should equally bear all the costs of DC link. For this purpose, a compensation mechanism must be arranged, potentially similar to the Inter-TSO mechanism describe in Recommendation No 5/2015 issued by ACER. The inter-TSO compensation serves as a balancing mechanism for countries, in which they receive compensation for the use of their network by external agents and conversely, pay a charge for the use they make of other countries’ networks. The national regulatory authorities (NRA) will then have to validate the results of this agreement and approve it.

From the conducted CBA the identified relevant cost and benefit categories are:

- Cost of DC link development (initial investment)
- Operational and maintenance costs (running expenditures)
- Benefits from avoided losses
- Benefits from increased availability

The initial allocation of the costs is such that all costs are to be incurred by the Swedish TSO. The reason is that the Swedish TSO will be directly managing the construction and procurement process for the asset located in its country. This is in line with the past experience of how investment costs were allocated by NRAs or ACER for the projects [18]. Furthermore, Swedish TSO would be responsible for the maintenance and operation of the link as it is a primary asset owner. Thus, also this part of costs will be attributed to Sweden. On the opposite side, the benefits are distributed equally, as explained above. There will not be any transmission tariffs for the utilisation of link capacity since in Sweden the tariff only exists in customer connection points.

Summarising the above, it is recommended to split the costs of construction and operation equally between SvK and 50 Hertz. This cross-border cost allocation should be formalised as a binding contract between the involved parties with a clear specification of underlying assumptions, non-complying- and delay penalties [19]. The decision can consider scenarios with and without EU funding. Such a step would mitigate any delays that may occur due to renegotiations between project developers that may be necessitated by an adverse EU funding decision.

2.8.7 MARKET ARRANGEMENT AND REVENUE MODEL

It was discussed earlier in this chapter which operational and market rules would have to be applied for the utilization of the new link. The ultimate purpose of new connection is to reduce the power losses for the flows from
Sweden to Germany. Hence, it is beneficial to maximize utilization of the link so that larger costs are saved, provided that security rules are respected.

Depending on the availability of EU finance, a bigger part or the cost of the link construction will be initially incurred by the Swedish TSO, and later shared with 50 Hertz. The main way in which transmission network owners and operators gain income in the EU is through regulated transmission tariffs based on incentive regulation, in order to achieve economic efficiency in the absence of competitive pressure [16]. The nature of DC link is such that it helps to reduce the costs for losses which would otherwise be incurred by two TSOs. As mentioned earlier, under the Swedish regulatory regime no transmission tariff would not be imposed on such a link since it does not directly connect any customer. Nevertheless, the benefits of link utilization would save the TSO’s expenditures and allow to reduce transmission tariffs in the points where they are collected.

Hence, it is recommended to validate the feasibility of regulated revenues for such anticipatory investments under the regulatory regime in Sweden and Germany. Project developers will need to emphasize the added socio-economic benefits that the link is expected to bring. During the process a compatibility must be ensured with the CBCA as described in the previous section [14].

2.8.8 COMMERCIAL ISSUES. PROCUREMENT AND INTEROPERABILITY.

Not all key electrical equipment manufacturers offer HVDC CB's. It is likely that suppliers of converters for SWL and HPB may not be able to provide DCCB. Moreover, connecting converters of different manufacturers on the DC side will probably result in the withdrawal of existing warranty and maintenance contracts. The DC breakers may need to be purchased as “free-issued material”, which would automatically make TSO responsible for the overall system integration. SvK and 50 Hertz will in this situation face greater technical challenges and risk with limited resources. If the DCCB is to be implemented, an in-depth knowledge of the DC breaker product and its development steps needs to be in place.

Albeit the European tendency is one that requires suppliers to be able to source or supply the full infrastructure. The current view is that turnkey suppliers source all components, but we observe that the industry may be de-structuring and re-configuring into focused component producers and integrators. As such, integrators will need to source and accept responsibility for externally supplied components (like a car manufacturer sources components from 3rd parties). This may be a challenge in the early stages and will require strength of will from the buyers (TSOs, etc.).

We recommend that in order to manage procurement process, a responsible TSO has to provide all technical specifications which will ensure interoperability. In turn, suppliers will have to adjust their product design in such a way that its operation will comply with the specifics set in a tender issued by TSO. A de-risking approach is to test operation and compatibility of equipment using replicas. This test can be carried in an independent testing facility such as SHE Transmission National HVDC Centre or RTE testing facility. Once the equipment from different manufacturers is tested and the results are approved, it will be difficult for manufacturers to void their warranties.

The procurement issue highlights a need to clarify the roles of TSOs and the relevant suppliers and to have these explicitly reflected in the contractual arrangements. Technical interfaces and parameters, interface conditions and
requirements need to be identified and documented prior to contract award. Liability of the different parties must be agreed.

In PROMOTioN Work Package 11 we focus on "Harmonization". While it is recognised that standards will need to be set by industry umbrella organisations like Cigre and Cenelec, PROMOTioN has initiated a programme to identify gaps in standards and specifications, specifically related to HVDC. We also recognise the need for interoperability. In PROMOTioN, there has been extensive discussion about the ability to connect together equipment from different suppliers. This discussion forms a topic area within Work Package 11. It is seen as important that apparently standard materials and components from different suppliers can operate successfully together. We envisage this as a prerequisite for future development as any grid structure is likely to be built incrementally and thus through a process of sequential procurement processes where different suppliers may be selected. Lastly, in order to connect together HVDC without creating the losses that we try to remove by utilising HVDC there are some overriding choices that do need to be made, such as voltage choice. Attention to all these factors will lead to higher scale for certain choices and thus the opportunity for a manufacturing learning curve, which may be economically attractive.

2.9 CONCLUSIONS

During the course of PROMOTioN project it became clear that stakeholders perceive deployment of meshed offshore grid as a highly risky endeavour because of the technical, regulatory and business innovations that would have to be integrated at once. European Commission has explicitly requested PROMOTioN to study opportunities to de-risk implementation of meshed offshore grid by highlighting existing or planned projects where different innovations could be piloted gradually without too many uncertainties. PROMOTioN has identified a range of such projects, where newly developed HVDC protection, regulatory, market and business models, ownership schemes and other project findings could be applied to prove their commercial readiness, at the same time keeping risks manageable.

A connection between two planned DC corridors – SouthWest Link in Sweden and Hansa Power Bridge between Sweden and Germany is an example of such a project, where adding DC circuit breaker and creating a multiterminal, multi-vendor grid element could lead to an increase in socio-economic welfare, at the same time allowing to test new protection technologies. SouthWest Link is a DC corridor in Sweden that is planned to go in operation in late 2020, while Hansa Power Bridge is an interconnector that is planned to be jointly operated by Svenska Kraftnät and 50 Hertz from 2026 onwards. Both cables are landing in Hurva (Sweden) substation, in a close proximity to each other.

It was initially assumed that by connecting two cables directly on DC side it will be possible to avoid conversion losses and increase availability of the transmission corridor for the power flows. To enable such a connection HVDC circuit breaker is a key component that must be utilised so that the grid is fully protected. Currently there is little experience with HVDC circuit breakers in commercial environment, thus PROMOTioN has performed a range of studies to recommend an approach to tackle technical, business and regulatory implications of such a project and prove its attractiveness.
As a result of technical studies, where two different options of DCCB were analysed, it turned out that the proposed connection is able to clear potential faults, hence protecting connected parts of the grid and decreasing the risk of outage on both sides. A range of dynamic simulations has been performed in order to select auxiliary components, switchgear and control systems of proper ratings that would enable implementation of such a link with different types of DCCB that have been successfully tested before. The particular case of having converter stations that are not expected to be fully utilised while the SWL and the HPB are connected results in several significant benefits that could be gained when considering future expansion, i.e. building Hansa Power Bridge 2. It is important that TSOs operating SouthWest Link and Hansa Power Bridge, in order to allow for such a connection, will need to design Hansa Power Bridge accordingly, i.e. it is essential that to enable the future realization of the DC connection, the HPB Hurva converter DC switchyard design foresees the provision of a physical connection point. Furthermore, the insulation coordination of the Hansa Power Bridge must be compatible with that of the South West Link. Several other characteristics of two links, such as the temporary overvoltage characteristics of the Hansa Power Bridge, insulation coordination and system earthing would have to be designed to be compatible between SouthWest Link and Hansa Power Bridge.

In the conducted Cost Benefit Analysis, it was shown that even though DCCB and other components would have a large total cost, the project has potential benefits that can outweigh these high costs. It was shown that the total cost of the link with all required equipment and hybrid DCCB would amount to 57.9 million Euro, while slower mechanical DCCB, albeit requiring larger DC inductor would only result in 16.8 million Euro. When looking at the benefits, we have analysed the monetary values of reduced losses and socio-economic welfare and reduced re-dispatch/ balancing costs due to increased link availability. The analysis has shown that they could amount to 54.45 million Euro, thus significantly exceeding the cost of link with mechanical DCCB and being slightly less than the cost of the link with hybrid DCCB.

Seeing that in one of the possible configurations the cost is higher than the benefits, we have reviewed available options of financing by European Commission which are specifically targeted at technically innovative projects with significant cross-border impact on EU Member States. It is believed that CEF financing could be an applicable option to further de-risk the project and allow for its realization by providing monetary support to the involved TSOs. The project satisfies some of the criteria to be included in PCI list and is located in one of the so-called priority corridors for energy infrastructure investment. Hence there is a good incentive for a further investigation in this direction.

Finally, an overview was made of some regulatory, business and procurement implications which would arise if the DC connection between two cables become implemented. It was shown that most of the issues related to governance, development, operation responsibility, cost allocation and benefits distribution can be surmounted following the guidelines.

The largest barriers that is remaining is related to procurement risks and multi-vendor interoperability. This barrier can be surmounted from the technical point of view, i.e. it has been proven in some other Horizon 2020 projects that HVDC interoperability could be achieved if sufficient procedures for the exchange of information and communication between different vendors are in place. There are several testing facilities in Europe where potential technical issues could be resolved before implementing the link. The biggest hurdles remain in the perception of involved stakeholders that see significant legal risks. These are related to the lack of clarity around liability for faults, monitoring procedures, warranties and performance guarantees. It remains unclear how to arrange such that these are equally shared among multiple TSOs and vendors in a real commercial environment.
PROMOTioN recommends a further investigation of this issues with the support of EC and EU. It is believed that technical and economic models have been progressed enough by PROMOTioN and other Horizon 2020 programs so that meshed offshore grid can be implemented. The next step in implementing projects in the short-term, such as the one reviewed in this document, is to develop methodologies for commercial and procurement risk management.
3 WINDCONNECTOR PROJECT

3.1 INTRODUCTION

One of the key aims of the PROMOTiOn project is increasing the TRL of DC grid equipment. DC circuit breakers and the associated protection equipment are of particular interest, not only because they are key in realizing multiterminal DC grids [20] [21], but also because of a complete lack of field operational experience with DCCBs for the European TSOs. While several DCCBs are already installed and operational in China [21], not a single one has yet been trialled in Europe. Advancing the TRL of DCCBs is therefore critical to maintain competitiveness of European industry in this sector.

This chapter is dedicated to the so-called WindConnector or Ijmuiden Ver hybrid asset, which aims to connect two offshore wind farms, one feeding British continental grid and the other feeding into Dutch power grid, which are geographically separated by around 60 km. This would establish a VSC-HVDC power transmission link between the United Kingdom and Netherlands and create a new hybrid asset that combines energy evacuation and energy trading functionalities.

The following reasoning and key triggers of the interconnection between the Netherlands and the UK have been reported [22] (this is applicable only if capacity of two HVDC links is available (low wind)).:

- Infrastructure is needed to improve system flexibility and stability. Decreasing system flexibility and stability is being registered, e.g. load ramps may not simply be met with a country’s installed thermal generation. The interconnector project between Netherlands and UK is designed as a HVDC-link. The full controllability of the HVDC link facilitates the balancing of active and reactive power in the Dutch and UK grid.
- Infrastructure is required to address system adequacy deficiencies due to significant changes in the generation mix. This project has an important adequacy contribution due to decreasing figures of installed conventional generation and increasing RES and in particular in light of the (UK) phase out of coal fired generators.
- Infrastructure is required to mitigate RES curtailment and to improve accommodation of flows. RES integration implies higher flows in the meshed AC-grid and/or hybrid transmission assets facilitating both RES integration as well as interconnection capacity and thus increases the need for cross border transmission capacity. This project satisfies this need in a cost-efficient manner.
- Infrastructure supports the reduction of the high price differentials (by adding capacity) across EU borders and synchronous systems between the UK and mainland Europe. This project increases the degree of interconnectivity between the Dutch and UK bidding zone. The possibility of higher market exchanges between these two bidding zones leads to a higher price convergence in more hours of a year and reduces therefore the price differentials.

Currently Dutch TSO Tennet is standardising on the build of HVDC platforms for the evacuation of wind energy from offshore wind. Two platforms are planned for construction at Ijmuiden Ver. In the UK sector, Vattenfall has won tenders to build Offshore Wind off the east coast of the UK in the Norfolk Vanguard and the Norfolk Boreas zones. These developments have resulted in the consideration of various options for the construction of the required infrastructure. These include:
1. Connection of the two TenneT platforms to facilitate a redundant path should there be problems with one of the links to shore.
2. A link from one of the Ijmuiden Ver platforms to the UK
3. A link from Ijmuiden Ver to one of the Vattenfall Norfolk Platforms and through to the UK.
4. (A possible link between the Vattenfall Norfolk platforms)

A graphical representation of the projects is given below in Figure 37, Figure 38.

Figure 37 Scenario 2 Ijmuiden Ver to UK direct

Figure 38 Scenario 3 Ijmuiden Ver to Norfolk

The currently favoured concept is Scenario 3 where one Ijmuiden Ver platform will be connected via the Vattenfall Norfolk Boreas platform to the UK. The proposals for Ijmuiden Ver are for a 2 GW capacity per platform, 525 kV HVDC. These platforms will be connected to the Netherlands using a 2 GW bipole system with dedicated metallic return cable. The UK is considering a similar configuration albeit with a capacity of 1.8 GW. This is due to the onshore limits requiring that a single connection to the grid may not exceed 1.8 GW in the UK. The interconnector is also planned at 1.8 GW capacity. The main savings between the reference case (an independent cable from the Netherlands to the UK) and the Hybrid case is that in the Hybrid Case the Interconnector is 60 km versus the 190 km in the reference case, and there are 2 less converters required.

This document currently considers only Scenario 3 and technical solutions for this model.

The hybrid asset introduces some novel reliability concerns. In particular, connecting the British and Dutch wind farms via a common HVDC link would expose either side to DC faults on the other side, as well as DC faults on the interconnector cable. If conventional ACCB protection for point-to-point HVDC systems is employed, all four converters in the grid would need to be tripped and isolated from the AC side before the interconnector could be
disconnected, and the power flow on the healthy portion of the link could resume. This creates a plethora of technical issues, the main ones being:

- Suddenly disconnecting a large load/power source on the onshore side may cause instabilities or frequency deviations in the onshore AC grid.
- Voltage collapse at the offshore AC grid, which may cause wind turbines to trip and disconnect.
- Restarting the tripped converters and wind turbines may be slow, and the outage can be costly if it occurs during peak times.

To mitigate these issues, the Dutch TSO TenneT considers installing the DC circuit breaker on the interconnector cable at the Ijmuiden Ver platform. The breaker would protect the Dutch converters from the faults on the British side and the interconnector cable, and consequently greatly improve the reliability and security of power supply. Assuming a bidirectional DCCB is employed, the breaker would also protect the British side from the faults on the Dutch subsea link.

This report contains a preliminary assessment of the interconnector protection system. Basic technical specifications, and a comprehensive study on the effects of DCCB installation is undertaken. The minimal DCCB ratings are provided, and should serve as an initial draft of the final DCCB specifications. Furthermore, PROMOTioN has analysed economic implications and distribution of revenue from energy production and trading under various bidding zone arrangements. An estimate of total costs for different grid options was performed based on the available bill of materials needed to realise different grid concepts. Finally, we present a high-level discussions of various barriers that still need to be resolved in order to implement the project, as deemed by involved stakeholders.

3.2 TECHNICAL CONSIDERATIONS

Technical options may differ for the UK portion of the cables. TenneT has a strong preference for a system that operates at the same 525 kV voltage as the evacuation cable from offshore platform to shore, and has a similar bipole configuration with dedicated metal return. A lower voltage would be possible but will likely result in a reduced power transfer capability of the bipole system of Ijmuiden Ver. Secondly, a less obvious problem is the necessity to adapt the converter valve side voltages to the reduced DC voltage in order to avoid over-modulation problems.

The interconnection capacity may determine to a certain extent whether the WindConnector configuration will be regarded as a "small impact" or "medium impact" DC grid, as seen from the AC side. It is assumed that for interconnection capacity of up to 1.8 GW (maximum allowed loss of power infeed in UK), a non-selective protection system would be the most favourable one, therefore DC breakers could be avoided (from a system stability point of view). However, for higher interconnection capacities, a partially selective protection system, including current breaking equipment in strategic offshore locations, might become necessary to ensure security of supply.

Due to lack of detailed data at this time, there cannot be any final conclusions at this stage for the protection system of the WindConnector based on Ijmuiden Ver system. For the time being, it can only be assumed that limited, if any, extra components will be needed to cope with the additional current stresses to be experienced during a DC-side fault when all 4 converter terminals are operating together. Without DC breaking capability, in
case of fault anywhere in the multi-terminal system, all converter terminals will need to shut down immediately, wait for complete discharge, isolate faulty section and then re-energise.

Different options have been considered:

1. Only conventional DC disconnectors are used in the entire hybrid system (which could be seen as the base case for the WindConnector between two HVDC platforms). It will not be possible to interconnect the two offshore platforms if they are not energised at the same time from the two onshore stations. This requires that the scheduled maintenance has to be always aligned between TenneT and the UK operator. The additional elements for this solution, compared to the no WindConnector solution, would be:
   a. DC disconnectors (4 in total),
   b. Earthing switches (8 in total),
   c. DC voltage dividers (4 in total),
   d. Surge arresters (4 in total),
   e. Zero-flux CT’s (4 in total),
   f. DC cable terminations (4 in total),
   g. Extension of DC busbar.

2. For energising the wind farms, the UK station is responsible to energise only the Vattenfall offshore station and TenneT is responsible to energise only Ijmuiden Ver station. The flow between the two offshore platforms would be possible at all times, as long as both platforms are already operational. The following elements would be necessary (for the interconnecting DC cable branch only):
   a. 4 High-speed switches (HSS’s) in total (one per cable pole end),
   b. the associated DC disconnectors (4 in total)
   c. Earthing switches (12 in total),
   d. DC voltage dividers (8 in total in worst case scenario),
   e. Surge arresters (4 in total),
   f. Zero-flux CT’s (4 in total),
   g. DC cable terminations (4 in total),
   h. Extension of DC busbar.

3. The offshore stations should have the possibility to be energised by any of the two onshore stations, while keeping the features as outlined in the 2nd option and without interrupting the existing power flows. The following additional components would have to be added:
   a. 2 discharge resistor units along with their own HSS to enable fast discharge process of interconnecting DC cable section
   b. 4 DC-side pre-insertion resistor units (2 per platform) with their own bypass HSS’s
   c. 4 pole HSS’s in total (one per cable pole end),
   d. The associated disconnectors (4 in total),
   e. Earthing switches (12 in total),
   f. Voltage dividers (8 in total in worst case scenario),
   g. Surge arresters (4 in total),
   h. zero-flux CT’s (4 in total),
   i. DC cable terminations (4 in total) and
   j. Extension of DC busbar.
4. Adding DC breakers to the above design options is analysed here. In case of DC breakers, the Ijmuiden Ver system will become immune to any fault events that may take place in the UK part of the WindConnector. In addition to the list of components from Option 3, 4 DC breakers (bi-directional) would have to be added, with one per pole on each cable end.

In the following section of this report a potential for DC breaker utilization, as described in Option 4 will be explored.

3.3 TECHNICAL STUDY

3.3.1 MODEL OF THE MAIN CIRCUIT

The single-line diagram of the Ijmuiden interconnector is shown in Figure 39. The system consists of two bipolar HVDC-connected wind farms, 2x1000 MW Ijmuiden Ver Dutch wind farm and 2x900 MW Norfolk British wind farm. However, the case with the 2x600 MW Norfolk wind farm is also considered. The proposed interconnector cable 24 would connect the Norfolk and Ijmuiden Ver wind farms and indirectly the British power system with the continental European power system. The transmission system is bipolar with the nominal voltage level of ±525 kV.
The system is grounded at one point in order to prevent ground currents. The default grounding point is the DMR bus at the Ijmuiden Ver offshore terminal, and 0.5Ω electrode resistance is assumed. Alternative grounding points are located at the DMR busses at the remaining three terminals. Only one MRTB is closed at a time when interconnector DC CB is closed. If the systems are separated, then each HVDC will have one grounding point.

Each OWF is separated into two groups of generators, which are independently connected to each converter pole. A bus transfer switch (BTS) for parallel operation exists on the AC bus, but this mode of operation is out of the scope of this study. Therefore, both BTSs will be assumed permanently opened.

Figure 39 also illustrates the location and naming of DC current measurements used in this report. To improve legibility, the complete current measurements are shown only for terminal 1, while the remaining terminals have only the positive pole measurements labelled. For each terminal, the total DMR current is the sum of DMR currents from both poles, which is written as:
\[ I_{x,DMR} = I_{x,dp} + I_{x,dn}, \quad x = 1,2,3,4 \]  

These currents are summed up internally on each DC bus, but this is not visible from the single-line diagram.

### 3.3.2 MODULAR MULTILEVEL CONVERTERS

The nominal rating of British converters is 2x900 MW, while the Dutch MMCs are rated for 2x1000 MW. The MMC parameters are outlined in Table 16 and specified per pole. The table also contains system parameters of AC 1 and AC 3 which are modelled as voltage sources with series RL impedance. AC 2 and AC 4 are on the other hand modelled as controllable power (current) sources. The rated voltage of AC systems corresponds to the ratings of the connected converters. The possibility of British converters being rated for 2x600 MW is also considered. The parameters of MMCs 1 and 2 for that case are given in Table 17.

The MMC self-protection blocks on overcurrent protection. Overcurrent protection operates if the current in any of the arms exceeds two times the rated arm current, which results in a blocking threshold of 4 kA. In this study, both the permanent and temporary MMC blocking are considered.

With permanent blocking, the tripped converter immediately sends out the opening signal to the corresponding ACCB, which opens in 60 ms. With temporary blocking, sending the opening signal to the ACCB is suspended for one grid period (20 ms). If the arm current falls below the de-blocking threshold (set to 1.2 p.u. (2.4 kA)) in this period, it is assumed that the fault has been successfully neutralized. The MMC is de-blocked and the ACCB opening command is cancelled. If the arm current does not fall below 1.2 p.u. within 20 ms, it is assumed that the fault has not been neutralized and the ACCBs are tripped. Since a separate ACCB is used on each pole, the pole protection systems are completely independent of each other.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>MMC 1</th>
<th>MMC 2</th>
<th>MMC 3</th>
<th>MMC 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rated power</td>
<td>900 MW</td>
<td>900 MW</td>
<td>1000 MW</td>
<td>1000 MW</td>
</tr>
<tr>
<td>Rated DC voltage</td>
<td>525 kV</td>
<td>525 kV</td>
<td>525 kV</td>
<td>525 kV</td>
</tr>
<tr>
<td>Rated AC voltage (L-L)</td>
<td>400 kV</td>
<td>400 kV</td>
<td>400 kV</td>
<td>400 kV</td>
</tr>
<tr>
<td>Arm inductance</td>
<td>46.7 mH</td>
<td>46.7 mH</td>
<td>42 mH</td>
<td>42 mH</td>
</tr>
<tr>
<td>Cell capacitance</td>
<td>9 mF</td>
<td>9 mF</td>
<td>10 mF</td>
<td>10 mF</td>
</tr>
<tr>
<td>Cells per arm</td>
<td>250</td>
<td>250</td>
<td>250</td>
<td>250</td>
</tr>
<tr>
<td>Transformer voltage rating</td>
<td>400/300 kV</td>
<td>66/290 kV</td>
<td>400/300 kV</td>
<td>66/290 kV</td>
</tr>
<tr>
<td>Transformer series reactance</td>
<td>0.15 p.u.</td>
<td>0.15 p.u.</td>
<td>0.15 p.u.</td>
<td>0.15 p.u.</td>
</tr>
<tr>
<td>Nominal AC frequency</td>
<td>50 Hz</td>
<td>50 Hz</td>
<td>50 Hz</td>
<td>50 Hz</td>
</tr>
<tr>
<td>Positive sequence impedance (AC 1 and 3)</td>
<td>0.58 + 5.28j</td>
<td>-</td>
<td>0.58 + 5.28j</td>
<td>-</td>
</tr>
<tr>
<td>Zero sequence impedance (AC 1 and 3)</td>
<td>1.25 + 12.51j</td>
<td>-</td>
<td>1.25 + 12.51j</td>
<td>-</td>
</tr>
</tbody>
</table>

Table 17 – MMC and AC system parameters (600 MW UK side)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>MMC 1</th>
<th>MMC 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rated power</td>
<td>600 MW</td>
<td>600 MW</td>
</tr>
<tr>
<td>Rated DC voltage</td>
<td>525 kV</td>
<td>525 kV</td>
</tr>
<tr>
<td>Parameter</td>
<td>MMC 1</td>
<td>MMC 2</td>
</tr>
<tr>
<td>---------------------------------</td>
<td>---------</td>
<td>---------</td>
</tr>
<tr>
<td>Rated AC voltage (L-L)</td>
<td>400 kV</td>
<td>400 kV</td>
</tr>
<tr>
<td>Arm inductance</td>
<td>70 mH</td>
<td>70 mH</td>
</tr>
<tr>
<td>Cell capacitance</td>
<td>6 mF</td>
<td>6 mF</td>
</tr>
<tr>
<td>Cells per arm</td>
<td>250</td>
<td>250</td>
</tr>
<tr>
<td>Transformer voltage rating</td>
<td>400/300 kV</td>
<td>66/290 kV</td>
</tr>
<tr>
<td>Transformer series reactance</td>
<td>0.15 p.u.</td>
<td>0.15 p.u.</td>
</tr>
<tr>
<td>Nominal AC frequency</td>
<td>50 Hz</td>
<td>50 Hz</td>
</tr>
<tr>
<td>Positive sequence impedance (AC 1)</td>
<td>0.58 + 5.28j</td>
<td>-</td>
</tr>
<tr>
<td>Zero sequence impedance (AC 1)</td>
<td>1.25 + 12.51j</td>
<td>-</td>
</tr>
</tbody>
</table>

### 3.3.3 SYSTEM CONTROLLER

The terminal 3 as the largest inverter is set as the DC voltage regulating terminal. The Terminal 1 controls power with a DC voltage droop feedback. The DC voltage droop is set high, to enable full power runback in case of 20% DC voltage variation.

Terminals 2 and 4 are in grid forming control and they regulate local AC voltage. They will pass all wind power to the DC grid. No droop is employed.

### 3.3.4 WIND FARM MODEL

Wind farms are modelled as controllable current sources. Current magnitude is adjusted in a power feedback loop according to a set power reference.

The wind plant regulator has an additional power limiting loop which is necessary in case that DC system cannot evacuate all wind power. This loop represents the action of energy dissipation choppers on wind generators and slow blade pitching controllers. The controller responds to AC voltage increase (with a 10% dead band) and limits the offshore voltage to 1.2 p.u.

### 3.3.5 DC CIRCUIT BREAKER

#### 3.3.5.1 BIDIRECTIONAL DC CB

The purpose of this study is assessing the benefits of installing a DC circuit breaker on the Dutch side of the interconnector cable. DCCB 42, as shown in Figure 39, would protect the Dutch side from DC faults on cables 12 and 24. If a bidirectional DCCB is installed, it would also protect the British side from the faults on cable 34. Without the DCCB, a fault on any cable would need to be cleared by opening of all four ACCBs. This would permanently halt the power transfer on both the British and the Dutch side for the faulted pole. In case of a pole-to-pole fault, the whole system would be shut down.

The schematic of DCCB 42 is shown in Figure 40. A single breaking unit is installed on each pole and also on the dedicated metallic return. The DMR breaker is required to operate only in case of DMR to ground faults. Since the DMR is grounded (assumed from the Dutch side in the model), the voltage on the DMR will normally not exceed few kV although it can be higher during transients. It is presumed that the voltage and current ratings of
DMR breaker will be significantly lower compared with pole breakers. The DMR breaker can also assume mechanical topology with a longer opening time.

![Diagram of DCCB 42 schematic and placement](image)

The DCCB on each pole is modelled using the generic breaker model [23]. The main breaking unit ($S_{MB}$) consists of a current-breaking switch in parallel with a surge arrester (SA) while the residual current breaker (RCB) and the $di/dt$ limiting inductor are connected in series with the breaking unit. This study considers MB opening delays of 3, 5 and 8 ms, which represents both the hybrid and mechanical DCCBs. The RCB time-delay is 30 ms in all cases. Main DCCB model parameters are provided in Table 18.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rated current</td>
<td>2 kA</td>
</tr>
<tr>
<td>MB breaking current</td>
<td>16 kA</td>
</tr>
<tr>
<td>MB opening time</td>
<td>3, 5 or 8 ms</td>
</tr>
<tr>
<td>RCB opening time</td>
<td>30 ms</td>
</tr>
<tr>
<td>RCB breaking current</td>
<td>50 A</td>
</tr>
<tr>
<td>Rated TIV</td>
<td>788 kV</td>
</tr>
<tr>
<td>$L_{dc}$</td>
<td>Variable</td>
</tr>
</tbody>
</table>

All three DCCBs will most likely be controlled by a single IED (protection relay) which takes control of fault detection and protection coordination on the whole DC bus [24]. A practical IED will utilize a wide range of input and output signals, but in this study only a simplified IED model is considered. The IED, which is discussed in detail in the section below, takes the voltage measurements from Figure 40 as inputs and generates control signals for the RCBs and $S_{MB}$’s on each conductor.

### 3.3.5.2 UNIDIRECTIONAL DC CB

It is assumed that a unidirectional DCCB has a unidirectional valve in the main breaker and also in the load commutation switch. It always conducts negative current through the diodes, and therefore cannot interrupt the...
current in that direction. Once fully opened (after RCB opens), a unidirectional DCCB will block in both directions, but this requires special consideration because the current direction could change while the DCCB is in the opening process (possibly 20-30 ms interval).

It is assumed that the unidirectional DCCB is adequately designed to avoid any internal damage, which includes additional bypass semiconductors in parallel with diodes in order to take the fault current. This is analysed further in Section 0. In principle, the relay should not trip the DCCB if a reverse (zone 2) fault is detected. Only zone 1 faults should result in DCCB tripping, and only on the affected pole, to avoid the risk of a fault current reversal (a change from positive to negative) midway through the opening process.

3.3.6 PROTECTION RELAY

3.3.6.1 FAULT DETECTION METHOD

Fault detection is performed independently for each pole using the rate-of-change-of-voltage (ROCOV) method [25], although a single physical device will most likely be utilized for the protection of both poles. The “relay” in this section therefore refers to the independent logical unit and not the physical unit, which is assigned separately to each pole. The voltage measurements are processed using the following transfer function:

\[ H(s) = \frac{s}{1 + sT_f} \]  

(2)

\( T_f \) is the smoothing constant of the noise-rejection low-pass filter whose value is set to 0.2 ms. Using the ROCOV method, the fault is detected if the obtained \( \frac{dv}{dt} \) from (2) is lower than the predefined threshold (\( \frac{dv}{dt} \) is negative). The suitable threshold value is determined by applying five types of DC faults on various places in the DC grid and measuring minimum \( \frac{dv}{dt} \) for each fault. The measurements are taken at the indicated places in Figure 40 and the voltage magnitude, rather than absolute value, is fed to the protection relay.

The applied fault types are positive-pole-to-ground (P-G), negative-pole-to-ground (N-G), DMR-to-ground (DMR-G), positive-to-negative-pole (P-N) and positive-to-negative-pole-to-ground (P-N-G). To ensure selective fault detection, a relay must detect all the faults involving its conductor while not tripping on the faults on the other conductors. For the relay on the positive pole, this means detection of P-G, P-N and P-N-G faults and the immunity to N-G and DMR-G faults. For the relay on the negative pole, N-G, P-N and P-N-G faults need to be detected while P-G and DMR-G faults need to be ignored.

3.3.6.2 FAULT DETECTION WITH ONE VOLTAGE SENSOR

The initial studies for protection threshold calibration are performed with a 100 mH inductor per pole, using fault resistances of 0.01 and 50 ohms. All possible fault types are considered but, because of pole symmetry and low-impedance DMR grounding, P-G faults can be interpolated to represent N-G, P-N and P-N-G faults as well. The table containing obtained ROCOV values for P-G faults and DMR-G faults is given in the appendix, while the summary is provided in Table 19.

For each pole, the measurements are taken at two locations: bus 4 (\( V_4 \)) and cable 24 (\( V_{42} \)), on the line-side of the DCCB reactor. DC grid is divided into two protection zones, which are indicated in Figure 39. Zone 1 covers cables 12 and 42 and the adjacent busses, while zone 2 covers the cable 34 and adjacent busses. \( V_{42} \) measurements are therefore better suited for detecting fault in zone 1, while \( V_4 \) measurements are suited for detecting faults in zone 2.
The “Min dv/dt for external faults” is the lowest measured ROCOV for faults outside of the assigned protection zone, including all faults on the other two conductors. The “Max dv/dt for internal faults” is the highest ROCOV measured for internal faults, in the corresponding protection zone and on the same conductor. This is the highest protection threshold setting which enables the relay to detect all the simulated internal faults. The ratio between the “Max dv/dt for internal faults” and “Min dv/dt for external faults” is the safety margin, and a higher number indicates greater protection sensitivity. The margin must be > 1, otherwise the internal and external faults cannot be distinguished from one another. The “Min dv/dt for internal faults” is the lowest ROCOV reading for any of the internal faults. A threshold setting below this value means that no internal faults would be detected. This number is provided merely as a reference, to give context to the other two values.

<table>
<thead>
<tr>
<th>Assigned protection zone</th>
<th>Zone 1</th>
<th>Zone 2</th>
<th>Zone 1 and 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Measurement</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>dV42p/dt [kV/ms]</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Min dv/dt for internal faults</td>
<td>-2052</td>
<td>-2051</td>
<td>-2052</td>
</tr>
<tr>
<td>Max dv/dt for internal faults</td>
<td>-523</td>
<td>-520</td>
<td>-61</td>
</tr>
<tr>
<td>Min dv/dt for external faults</td>
<td>-172</td>
<td>-159</td>
<td>-10</td>
</tr>
<tr>
<td>Safety margin</td>
<td>3.04</td>
<td>3.27</td>
<td>6.10</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>8.00</td>
</tr>
</tbody>
</table>

The results in Table 19 indicate that internal and external faults in zones 1 and 2 can be successfully distinguished from one another in both protection zones, using solely the voltage sensor located in that zone. The safety margin is greater than 3 in both cases, meaning that a distant high-impedance internal fault produces three times lower ROCOV than a low-impedance external fault in proximity of the voltage sensor (on the other side of \( L_{dc} \)).

\( V_{42} \) or \( V_4 \) measurements can also cover both protection zones simultaneously, and differentiate between faults occurring on the monitored pole (in either zone 1 or zone 2) from the faults occurring on the other pole or the DMR. This mode of operation is useful if the DCCB is bidirectional. The maximal dv/dt for internal faults is reduced by a factor of 9 compared to the case where each relay covers only one protection zone, illustrating the low-frequency filtering impact of the DCCB reactor. On the other hand, the minimal dv/dt for external faults is reduced by a factor of 20. This shows that even very severe faults on the opposite pole or the DMR have little impact on the voltage of the non-faulted pole, compared to the faults on the same pole in a different protection zone. Consequently, the safety margin more than doubles when a sensor can detect faults in both protection zones.

### 3.3.6.3 Fault Detection with Two Voltage Sensors

Although discriminative fault detection with one voltage sensor is possible, utilizing two sensors can greatly enhance protection sensitivity and considerably increase the safety margin. The logic of a protection relay with two voltage sensors is shown in Figure 41, and a separate configuration is used for a unidirectional and a bidirectional DCCB.
Figure 41 (a) shows the relay logic for a unidirectional DCCB with two sensors. The DCCB is tripped if the fault is detected by $V_{42}$ but not $V_4$. The benefit of this approach is that $V_4$ measurements can be calibrated to detect both zone 1 and 2 faults on the same pole, but the trip signal will not be issued if $V_4$ simultaneously detects a fault on the same pole in zone 2. $V_4$ then only needs to avoid detecting faults on the other pole and the DMR, which, as demonstrated in Table 19, greatly improves the sensitivity of the protection method.

The minimal, maximal and recommended thresholds for each relay ($dV_{42,th}$ and $dV_{4,th}$) are provided in Table 20. The lower limit for the $V_{42}$ ROCOV threshold is the same as in the “Zone 1” column in Table 19, because the sensor is still only required to detect zone 1 faults. However, because $V_4$ will override detection by $V_{42}$ in case of an obvious fault in zone 2, the upper limit for the $V_{42}$ ROCOV threshold increases all the way to -10 kV/ms (which avoids the detection of faults on the other two conductors). The end result is a major increase in the safety margin to 52.3, which indicates superb sensitivity and is more than sufficient for practical applications.

The relay logic for a bidirectional DCCB is shown in Figure 41 (b), which must trip the breaker if a fault occurs in either zone 1 or zone 2, but only on the affected pole. In this case, both $V_{42}$ and $V_4$ measurements need to merely distinguish between a fault on the assigned conductor and the other two conductors (DMR and the other pole). This is considerably easier to achieve than distinguishing between faults on the same conductor, as shown in Table 19. The minimal and maximal ROCOV threshold, as well as the recommended setting, are given in Table 20. As in the unidirectional case, an overall safety margin of 52.3 is achieved, although the margin for zone 2 faults is even higher, at 74.3.

Table 20 – Minimal, maximal and recommended ROCOV thresholds for a unidirectional and bidirectional DCCB

<table>
<thead>
<tr>
<th>DCCB Measurement</th>
<th>Unidirectional</th>
<th>Bidirectional</th>
</tr>
</thead>
<tbody>
<tr>
<td>$dV_{42}/dt$</td>
<td>-523</td>
<td>-523</td>
</tr>
<tr>
<td>$dV_4/dt$</td>
<td>-520</td>
<td>-520</td>
</tr>
<tr>
<td>Minimal $dv/dt$</td>
<td></td>
<td></td>
</tr>
<tr>
<td>threshold [kV/ms]</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Maximal dv/dt threshold [kV/ms] | -10 | -159 | -10 | -7  
---|---|---|---|---
Recommended threshold [kV/ms] | -300 | -300 | -300 | -300  
DCCB trip logic | $dV_{42}/dt < dV_{42,th}$ AND $dV_4/dt > dV_{4,th}$ OR $dV_4/dt < dV_{4,th}$ | $dV_{42}/dt < dV_{42,th}$ OR $dV_4/dt < dV_{4,th}$  
Safety margin | 52.3 | 52.3

The two-sensor fault detection methods are clearly superior to the one-sensor method, and the increase in cost (one voltage sensor) is negligible. In all the simulation studies in this report, two-sensor methods are employed (depending on the DCCB type), using the recommended thresholds from Table 20.

### 3.3.7 DMR CIRCUIT BREAKER

The fault detection and protection logic for DMR faults is not studied in this report. The DMR protection is both less critical and less demanding (in terms of speed) since DMR voltage is low and DMR faults will not cause high currents. A DMR ground fault will not cause any component damage, but ground current will be present until fault is cleared. Therefore, slow DC CB may be used. The HVDC bipolar operation with DMR isolated may or may not be allowed depending on the operating principles, but monopolar operation will certainly not be allowed. Also, detection logic may need different approaches from the traditional line fault detection.

### 3.3.8 NEUTRAL BUS SWITCHES

The location of neutral bus switches is shown in Figure 39. NBSs are necessary to prevent converters from feeding the DC fault through the antiparallel diodes while in blocked state. Fault feeding occurs even after ACCB tripping, and is caused by the potential difference between the DMR and the fault.

The fault feeding is illustrated in Figure 42 for a P-G fault. MMC p has been blocked, and the fault has been cleared by opening ACCB p. MMC n resumes operation as a rectifier, and DMR assumes the role of a return conductor. For simplicity, only one leg of each MMC in a bipole is shown, and only one cable is connected to each DC bus. In this example, the DMR is grounded on a remote bus, but the same principles apply if the grounding is on the same bus.

Since DMR takes the full load current of the negative pole post-fault, a potential difference arises between the two ends of the DMR cable due to internal cable resistance. Because the DMR is grounded at a single point (and the grounding resistance $R_G > 0$), it is necessary that the DMR voltage at the sending bus $V_{DMR}$ is positive with respect to ground for the given direction of $I_{DMR}$. The single-point grounding of DMR prevents earth currents in normal circumstances, but in this case the ground connection also exists on the positive-pole cable because of a P-G fault. The positive voltage difference between the DMR and ground forward-biases the antiparallel diodes of the blocked MMC p, and drives the fault current through the loop closed through the DMR grounding and the earth fault. The fault current is subtracted from the load current provided by MMC n, and generates additional power losses.
The role of NBS is to break the fault-feeding ground current and isolate the blocked converter on the DC side. Since $V_{DMR}$ is usually in the range of several kV, NBS operates at a low current and voltage rating compared to DCCB 42. It can be implemented as a low-cost passive-resonant circuit breaker, rated for tens of kilovolts, with breaking capacity below the rated load current. The voltage rating of NBS’s MB commonly corresponds to the voltage on DMR. Key parameters for NBS dimensioning are shown and discussed in section 3.3.10.2. They are used to determine the NBS model parameters, which are provided in Table 21. The NBS is also represented by the generic DCCB model [23], and has the same layout as the single-pole DCCB from Figure 40.

Table 21 – NBS model parameters

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rated current</td>
<td>2 kA</td>
</tr>
<tr>
<td>MB breaking current</td>
<td>500 A</td>
</tr>
<tr>
<td>MB opening time</td>
<td>20 ms</td>
</tr>
<tr>
<td>RCB opening time</td>
<td>30 ms</td>
</tr>
<tr>
<td>RCB breaking current</td>
<td>10 A</td>
</tr>
<tr>
<td>Rated TIV</td>
<td>30 kV</td>
</tr>
<tr>
<td>$L_{dc}$</td>
<td>Variable</td>
</tr>
</tbody>
</table>

3.3.9 LOAD FLOW ANALYSIS

3.3.9.1 BOTH POLES OPERATIONAL

Figure 43 shows the grid response to the test case outlined in Table 22. The currents are shown at each converter terminal, while voltages are only shown for onshore terminals for legibility. Colour coding is: red – positive pole,
green – neutral, blue – negative pole. The test case demonstrates interconnector operation with power transfer from the UK to NL side, followed by ramping up the OWF power output which results in full power reversal at terminal 3. All controllers operate as expected, and the DC voltages are controlled in a narrow range. MMC 1 maintains constant power output even as the wind power changes.

Table 22 – Control test of bipolar operation

<table>
<thead>
<tr>
<th>Time</th>
<th>Terminal 1 UK onshore</th>
<th>Terminal 2 UK offshore</th>
<th>Terminal 3 NL onshore</th>
<th>Terminal 4 NL offshore</th>
</tr>
</thead>
<tbody>
<tr>
<td>0 – 1.5 s</td>
<td>Controls power at 0 MW</td>
<td>Power is 0 MW</td>
<td>Controls DC voltage. Power at 0 MW.</td>
<td>Power is 0 MW</td>
</tr>
<tr>
<td>1.5 - 2.6 s</td>
<td>Power ramp from 0 to 1800 MW</td>
<td>Power is 0 MW</td>
<td>Controls DC voltage. Power increases from 0 to 1800 MW.</td>
<td>Power is 0 MW</td>
</tr>
<tr>
<td>3.0 - 3.8 s</td>
<td>Controls power at 1800 MW</td>
<td>Power ramp to from 0 to 1800 MW</td>
<td>Controls DC voltage. Power reduces from 1800 MW to – 2000 MW.</td>
<td>Power ramp to from 0 to 2000 MW</td>
</tr>
</tbody>
</table>

The final voltage and current measurements for the test from Figure 43 are provided in Table 23. The measurements are taken at each terminal, as well as cable 24, The unit for voltage is kV and the unit for current is kA.

Table 23 – Final measurements at all terminals and cable 24 for bipolar operation control test

<table>
<thead>
<tr>
<th>Pole</th>
<th>I1</th>
<th>V1</th>
<th>I2</th>
<th>V2</th>
<th>I3</th>
<th>V3</th>
<th>I4</th>
<th>V4</th>
<th>I42</th>
<th>V42</th>
</tr>
</thead>
<tbody>
<tr>
<td>Positive</td>
<td>-1.732</td>
<td>526.2</td>
<td>1.675</td>
<td>527.4</td>
<td>-1.791</td>
<td>524.8</td>
<td>1.864</td>
<td>527.4</td>
<td>0.061</td>
<td>527.4</td>
</tr>
<tr>
<td>DMR</td>
<td>0.002</td>
<td>0.0</td>
<td>0.003</td>
<td>-0.0</td>
<td>-0.002</td>
<td>-0.0</td>
<td>-0.004</td>
<td>-0.0</td>
<td>0.001</td>
<td>-0.0</td>
</tr>
<tr>
<td>Negative</td>
<td>-1.731</td>
<td>-526.3</td>
<td>-1.678</td>
<td>-527.5</td>
<td>1.794</td>
<td>525.0</td>
<td>-1.860</td>
<td>527.6</td>
<td>-0.062</td>
<td>527.6</td>
</tr>
</tbody>
</table>

The average DMR current are voltage are zero, with small harmonic current (several amps) flowing through the conductor. The maximum DMR voltage observed at any terminal in steady-state is 50 V, which shows that the system is balanced and operates correctly.
Figure 43 – Terminal currents and voltages for full power ramps on MMCs 1, 2 and 4
### 3.3.9.2 NEGATIVE POLE ONLY

Figure 44 shows the grid response for a similar test case as in Table 22, but with only negative pole operational. The effective power output of each terminal is therefore halved. Positive poles of all four MMCs are blocked while the corresponding ACCBs are open. The DMR consequently assumes the role of a return conductor in this test, which indicates correct single-pole operation.

The final voltage and current measurements for this test are provided in Table 24. The DMR voltage at different points of the grid reaches up to 2.3 kV, depending on the load conditions. Meanwhile, the voltage of the positive pole reads 20.9 kV, even though the pole is completely disconnected from the AC systems. This residual voltage is a result of DC-side submodule capacitor charging through the positive pole MMC’s antiparallel diodes during transients. During this test, the NBS’ are deliberately maintained closed to demonstrate this point. If the test is repeated with NBS’ open, the positive pole is fully de-energized and the voltage is zero.

<table>
<thead>
<tr>
<th>Pole</th>
<th>I1</th>
<th>V1</th>
<th>I2</th>
<th>V2</th>
<th>I3</th>
<th>V3</th>
<th>I4</th>
<th>V4</th>
<th>I42</th>
<th>V42</th>
</tr>
</thead>
<tbody>
<tr>
<td>Positive</td>
<td>0.001</td>
<td>20.9</td>
<td>0.000</td>
<td>20.9</td>
<td>0.001</td>
<td>20.9</td>
<td>0.000</td>
<td>20.9</td>
<td>0.000</td>
<td>20.9</td>
</tr>
<tr>
<td>DMR</td>
<td>-1.728</td>
<td>-1.3</td>
<td>1.684</td>
<td>-0.1</td>
<td>-1.771</td>
<td>-2.3</td>
<td>1.858</td>
<td>0.0</td>
<td>0.044</td>
<td>0.0</td>
</tr>
<tr>
<td>Negative</td>
<td>1.734</td>
<td>-528.6</td>
<td>-1.677</td>
<td>-529.9</td>
<td>1.777</td>
<td>-527.5</td>
<td>-1.851</td>
<td>-529.9</td>
<td>-0.067</td>
<td>-529.9</td>
</tr>
</tbody>
</table>
Figure 44 – Terminal currents and voltages for full power ramps on negative poles of MMCs 1, 2 and 4
3.3.9.3 IMPACT OF DCCB INSTALLATION

POWER FLOW REVERSAL

The installation of DCCB reactors on cable 42 may have an adverse impact on transient system performance and stability. To investigate this matter, a full power reversal is performed between MMCs 1 and 3, which leads to a maximum load current change through cable 24. Figure 45 shows the powers at terminals 1 and 3 (per pole) for different inductor sizes (also given per pole). MMC 1 ramps the power from -900 to 900 MW while MMC 3, which regulates DC voltage, meets the demand.

Even with very large inductors (1000 mH per pole), no notable difference is observed between the base case without inductors (0 mH). The rate limiter of the power controller limits the maximum power slope to 1 p.u./s, and this has the dominant effect on the shape of response. Evidently, the addition of DCCB inductors does not limit the load current slope beyond the existing control limit.

Positive pole voltages for the examined test cases are shown in Figure 46. Larger inductance requires a slightly higher increase in the power-regulating MMC 1 voltage during the transient phase, but the difference is merely 2 kV. On the other hand, the voltage-regulating MMC 3 maintains the DC voltage in a very narrow range and there is practically no difference in voltage profiles between cases with different inductors.

![Figure 45 – Active powers at MMC 1 and 3 terminals during a full power reversal, for different DCCB 42 inductor sizes](image)
While this study indicates that the DCCB reactor does not slow down the power transfer through the interconnector, it does not mean that the installed inductance has no dynamic impact at all. Large DCCB inductors are shown to reduce the stability margin in DC grids [26], but this may only become apparent during large disturbances (such as DC faults or MMC blocking).

Figure 46 – Positive pole voltages at MMC 1 and 3 terminals during a full power reversal, for different DCCB inductor sizes.
REACTOR LOSSES

DCCB installation on cable 42 will result in increased conduction losses. Two main types of conduction losses are reactor losses (applicable to all DCCB topologies) and LCS losses (applicable only to the hybrid topology). This section evaluates DCCB reactor losses.

The reactor losses are evaluated as purely resistive losses. Because of very high current levels in DCCBs, virtually all DCCB reactors have an air core to prevent core saturation. Magnetizing and eddy current losses may occur in the metallic casing, but only during transients so their impact is negligible. It is assumed that the inductors are cooled through passive convection, so any potential cooling system losses are neglected.

The procedure for dimensioning DC reactors is outlined in [27]. A multi-layered, air-core inductor is considered.

The inductance of the coil can be approximated as

$$L_{coil} \approx 0.4 \cdot 10^{-6} \pi^2 \frac{a^2}{h} N^2 K$$

(3)

where $N$ is the total number of turns, $a$ is the average turn radius and $h$ is the height of the coil (assuming vertical mounting). $K$ is Nagaoka’s constant, defined as:

$$K = \frac{1}{1 + 0.9 \frac{a}{h} + 0.32 \frac{t}{a} + 0.84 \frac{t}{h}}$$

(4)

where $t$ is the thickness of multi-layered coil turns. The total number of turns $N$ is obtained as

$$N = N_{turns} \cdot N_{layers}$$

(5)

with $N_{turns}$ being the number of turns per layer and $N_{layers}$ being the number of layers. The radius of the coil wire is defined as

$$r_w = r_c k_{ins}$$

(6)

where $r_c$ represents the radius of the inner conductor while $k_{ins}$ is a factor >1 which accounts for insulation thickness. $r_c$ is adjusted based on the load current magnitude, in order to obtain satisfactory coil current density $J_{coil}$. $J_{coil}$ is typically in the range between 1 and 4 A/mm$^2$. When $r_w$ is known, the relationship between $h$ and $t$ is

$$h = 2 N_{turns} \cdot r_w$$

(7)

$$t = 2 N_{layers} \cdot r_w$$

(8)

The optimal value for $a$ is $3t/2$, as this maximizes the inductance according to (3). However, this results in a densely wounded coil and reduces the area for heat dissipation, so a higher value is usually applied for high-power applications. Mechanical factors such as the minimal wire bending radius may also be a limitation. By defining coefficient $k_a > 1$, $a$ can be expressed as a function of the optimal average turn radius:

$$a = \frac{3}{2} k_a$$

(9)

Once $a$ is known, the outer diameter of the coil is calculated as

$$D = 2a + t = (3k_a + 1) \cdot t$$

(10)

Total length of the coil wire is calculated by summing the length of turns in each layer:
Reactor resistance is then calculated as

\[ R_{\text{coil}} = \rho_{\text{Cu}} \cdot \frac{l_w}{\pi r_w^2} \]  

where \( \rho_{\text{cu}} \) is resistivity of copper.

There are multiple degrees of freedom in reactor design, and the optimal solution depends on various parameters such as the size, weight, cost and losses. Optimizing the inductor design is out of the scope of this report, and this study aims only to provide a rough estimate of the losses associated with installing a DCCB reactor.

The input parameters for the analysis are provided in Table 25. The rated current is obtained by assuming a 900 MW power transfer through the interconnector cable at the nominal system voltage of 525 kV. The rated current density is selected as 2 A/mm\(^2\). This represents a trade-off between conduction losses and smaller reactor size, which is important for offshore installations. The insulation thickness is assumed to be 10\%, and \( k_a \) is selected as 1.5, representing a trade-off between the inductor size and cooling system efficiency.

**Table 25 – Input parameters for the reactor design**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rated current</td>
<td>1714 A</td>
</tr>
<tr>
<td>Rated current density</td>
<td>2 A/mm(^2)</td>
</tr>
<tr>
<td>( k_{\text{ins}} )</td>
<td>1.1</td>
</tr>
<tr>
<td>( k_a )</td>
<td>1.5</td>
</tr>
<tr>
<td>( \rho_{\text{Cu}} )</td>
<td>1.73e-8 ( \Omega \text{m} )</td>
</tr>
<tr>
<td>( h/D )</td>
<td>1</td>
</tr>
</tbody>
</table>

The ratio between the inductor height and diameter is fixed to maintain the same shape of reactor regardless of its size. This ratio is selected as 1 as this fits the inductor in a square box and should minimize space usage, although the optimal inductor shape will depend on the actual application. Fixing the inductor shape also has the benefit of reducing the number of independent variables. From (7)-(10), the ratio between inductor height and diameter can be expressed as

\[ \frac{h}{D} = \frac{N_{\text{turns}}}{N_{\text{layers}}} \cdot \frac{1}{3k_a + 1} \]  

(13)

Since \( k_a \) is fixed in this design, as well as \( h/D \), the number of turns has become dependent on the number of layers. For the given input parameters, this yields:

\[ N_{\text{turns}} = (3k_a + 1) \cdot N_{\text{layers}} = 5.5 \cdot N_{\text{layers}} \]  

(14)

Using (7)-(9) and (14), Nagaoka’s constant for this particular coil shape can be expressed as a function of \( k_a \), which yields:

\[ K = \frac{1}{1 + 1.35 \cdot \frac{k_a}{3k_a + 1} + 0.32 \cdot \frac{1}{3k_a} + 0.84 \cdot \frac{1}{k_a + 1}} = 0.6013 \]  

(15)
From (5) and (14) the total number of turns is obtained as

\[ N = (3k_a + 1) \cdot N_{layers}^2 = 5.5 N_{layers}^2 \] (16)

Finally, using (15), (16) and the relationship between \( a \) and \( h \), (3) can be expressed as a function with a single independent variable \( N_{layers} \):

\[ L_{coil} \approx 0.4 \cdot 10^{-6} \pi^2 \cdot 4.5 \cdot k_a^2 \cdot (3k_a + 1) N_{layers}^5 \cdot r_w \cdot K = 2.4018 \cdot 10^{-6} N_{layers}^5 \] (17)

The total wire length can also be expressed as a function of \( N_{layers} \):

\[ l_w = 2\pi (3k_a + 1) \cdot N_{layers} \cdot \sum_{i=1}^{N_{layers}} r_w \cdot [(3k_a + 1) \cdot N_{layers} - (2i - 1)] \] (18)

By varying the parameter \( N_{layers} \) in (17)-(18) and using (12), the relationship between the reactor inductance and resistance is established. Figure 47 plots the reactor power loss and resistance against inductance, using the input parameters from Table 25. The resulting curve is obtained by interpolation between the discrete results of solving (17)-(18), since \( N_{layers} \) must be an integer. The interpolated results are meaningful because the intermediate inductance values can be easily achieved in practice by making slight adjustments to \( k_a \) or the \( h/D \) ratio. These adjustments would not have a significant impact on the coil shape and wire length, but would ensure that \( N_{layers} \) is an integer for any desirable \( L_{coil} \).

The relationship between \( L \) and \( R \) resembles an exponential function with an exponent < 1. As the inductance grows larger, the impact on reactor losses diminishes. The estimated power loss varies between 0.007% for a 100 mH inductor to 0.019% for a 1000 mH inductor.
Repeating the same process for the 600 MW interconnector rating (1143 A), the relationship between reactor inductance and $N_{layers}$ is obtained as:

$$ L_{coil} \approx 1.961 \cdot 10^{-6} N_{layers}^5 $$

(19)

The results for this case are shown in Figure 48. The L/R ratio of the reactor is similar to the one in the 900 MW case, but the losses are roughly 40% lower because of reduced load current. The estimated power loss varies between 0.006% for a 100 mH inductor to 0.016% for a 1000 mH inductor.

Table 26 contains all reactor dimensions for a coil with a target inductance of 100 mH, in both the 900 MW and 600 MW variant. The purpose is to provide a general estimate of the coil size, $k_a = 1.5$ in both cases.

Table 26 – Examples of 100 mH reactor dimensions

<table>
<thead>
<tr>
<th>Parameter</th>
<th>900 MW</th>
<th>600 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>$L_{coil}$</td>
<td>99.4 mH</td>
<td>99.1 mH</td>
</tr>
<tr>
<td>$N_{layers}$</td>
<td>9</td>
<td>9</td>
</tr>
<tr>
<td>$N_{turns}$</td>
<td>38</td>
<td>44</td>
</tr>
<tr>
<td>$N$</td>
<td>342</td>
<td>396</td>
</tr>
<tr>
<td>$r_w$</td>
<td>18.2 mm</td>
<td>14.8 mm</td>
</tr>
<tr>
<td>$t$</td>
<td>327 mm</td>
<td>267 mm</td>
</tr>
<tr>
<td>$h$</td>
<td>1.38 m</td>
<td>1.31 m</td>
</tr>
<tr>
<td>$D$</td>
<td>1.80 m</td>
<td>1.47 m</td>
</tr>
<tr>
<td>$l_w$</td>
<td>1581 m</td>
<td>1495 m</td>
</tr>
</tbody>
</table>

Figure 48 – Reactor power loss and resistance versus reactor inductance at 600 MW interconnector rating
LCS LOSSES

A detailed technical assessment of the load commutation switch is provided in [28]. In this analysis, only the conduction losses in IGBTs and diodes will be assessed, while additional losses (cooling system, arrester leakage etc.) will be neglected. However, the LCS will almost certainly require active cooling, given that it must be able to conduct load current for prolonged periods of time.

The LCS is generally implemented as a 2x2 or 3x3 IGBT matrix. For a bidirectional DCCB, 2 anti-parallel matrices are required to commutate the current in both directions. Consequently, the on-state losses differ between the unidirectional and bidirectional HCB topology, with the former being more economical.

A 3x3 LCS structure is considered in this assessment. A 4500 V, 2000 A press-pack IGBT from [29] is selected as a building block, and the same type of IGBTs will most likely be used in some commercially available HCB topologies [28]. Both the 900 MW and 600 MW interconnector ratings are considered. A single IGBT will conduct one third of the rated load current, which yields 571 A and 380 A respectively. The LCS current rating is not affected by the difference in load currents in these two cases because the voltage level, and therefore the current breaking requirements, stay the same. The selected LCS has a 13.5 kV, 6 kA rating, with an assumed 12 kA (2 p.u.) current breaking capability, since the IGBTs operate from the hot state.

From the I-V curves in [29], the on-state voltage drops of the transistor and the diode are obtained. Then, multiplying by load current yields the power loss per individual switch. The results are summarized in Table 27, and the values are given for both the hot (125 °C) and the cold (25 °C) state. The actual switch temperature will most likely be somewhere between those two values (under normal operating conditions), and so will the actual conduction losses. In the low current region, the diode exhibits inverse-proportional relationship between the temperature and conduction losses, so the hot-state voltage drop is slightly lower than in the cold state.

Table 27 – Forward voltage drop and power loss of IGBTs and diodes under load current

<table>
<thead>
<tr>
<th>Device current</th>
<th>Parameter</th>
<th>IGBT 25 °C</th>
<th>IGBT 125 °C</th>
<th>Diode 25 °C</th>
<th>Diode 125 °C</th>
</tr>
</thead>
<tbody>
<tr>
<td>571 A</td>
<td>Forward voltage drop [V]</td>
<td>1.6</td>
<td>1.85</td>
<td>1.85</td>
<td>1.85</td>
</tr>
<tr>
<td></td>
<td>Power loss [W]</td>
<td>914</td>
<td>1056</td>
<td>1056</td>
<td>1056</td>
</tr>
<tr>
<td>380 A</td>
<td>Forward voltage drop [V]</td>
<td>1.3</td>
<td>1.6</td>
<td>1.6</td>
<td>1.55</td>
</tr>
<tr>
<td></td>
<td>Power loss [W]</td>
<td>494</td>
<td>608</td>
<td>608</td>
<td>589</td>
</tr>
</tbody>
</table>

Table 28 shows the estimated power loss of the unidirectional and bidirectional LCS, which consist of 9 and 18 IGBT modules respectively. The losses are given in a range which accounts for a difference in LCS temperature. In a unidirectional LCS, the losses depend on the current direction because either the IGBTs or the diodes are conducting. In a bidirectional LCS, the losses are independent of the current direction because half of the IGBTs and half of the diodes conduct at any given time.

Table 28 – Forward voltage drop and power loss of unidirectional and bidirectional LCS

<table>
<thead>
<tr>
<th>Rated power</th>
<th>Parameter</th>
<th>Unidirectional</th>
<th>Bidirectional</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>IGBTs conduct</td>
<td>Diodes conduct</td>
<td></td>
</tr>
<tr>
<td>900 MW</td>
<td>Forward voltage drop [V]</td>
<td>4.8 – 5.55</td>
<td>5.55</td>
</tr>
<tr>
<td></td>
<td>LCS power loss [kW]</td>
<td>8.2 – 9.5</td>
<td>9.5</td>
</tr>
<tr>
<td>600 MW</td>
<td>Forward voltage drop [V]</td>
<td>3.9 – 4.8</td>
<td>4.65 - 4.8</td>
</tr>
</tbody>
</table>
LCS power loss [kW]  4.4 – 5.5  5.3 - 5.5  9.9 – 10.8

Because of nonlinear V-I characteristics of the IGBTs and diodes, the LCS losses for the 900 MW case are expected to be around 70% higher compared to the 600 MW case. Overall, the losses for the unidirectional and bidirectional LCS are 0.0010% and 0.0021% in the 900 MW case and 0.0009% and 0.0018% in the 600 MW case. This is several times lower than the reactor losses.

3.3.10 DC FAULT CLEARING

3.3.10.1 SYSTEM SET-UP

Identical pre-fault conditions are applied to all the tests undertaken in sections 3.3.10.2 and 0. The pre-fault measurements, taken right before the fault inception at 2.5 s, are provided in Table 29. MMC 3 controls DC voltage at 525 kV, while MMC 1 regulates power at -1800 MW. Both OWFs are operating at 1 p.u. power, so the MMCs 2 and 4 are providing 1800 MW and 2000 MW respectively. Table 29 shows that the currents and voltages are balanced just before the fault, and the DMR currents and voltages are negligible. The pre-fault current through cable 24 is close to zero, and the voltages at the both sides of the DCCB inductor are almost identical.

The power and voltage references at all terminals remain constant throughout each test, and any subsequent power adjustment is a product of the automated power system’s response to DC grid contingencies. Because of harmonics induced by capacitor switching, the pre-fault values in Table 29 may slightly differ from their average steady-state values.

Table 29 – Pre-fault variables at all terminals and cable 24

<table>
<thead>
<tr>
<th>Pole</th>
<th>I1</th>
<th>V1</th>
<th>I2</th>
<th>V2</th>
<th>I3</th>
<th>V3</th>
<th>I4</th>
<th>V4</th>
<th>I42</th>
<th>V42</th>
</tr>
</thead>
<tbody>
<tr>
<td>Positive</td>
<td>-1.732</td>
<td>526.1</td>
<td>1.682</td>
<td>527.6</td>
<td>-1.791</td>
<td>525.0</td>
<td>1.863</td>
<td>527.5</td>
<td>0.065</td>
<td>527.5</td>
</tr>
<tr>
<td>DMR</td>
<td>0.002</td>
<td>0.1</td>
<td>0.002</td>
<td>0.0</td>
<td>0.003</td>
<td>0.0</td>
<td>-0.004</td>
<td>0.0</td>
<td>-0.006</td>
<td>0.0</td>
</tr>
<tr>
<td>Negative</td>
<td>1.731</td>
<td>-526.0</td>
<td>-1.683</td>
<td>-527.6</td>
<td>1.788</td>
<td>-525.2</td>
<td>-1.859</td>
<td>-527.6</td>
<td>-0.062</td>
<td>-527.6</td>
</tr>
</tbody>
</table>

3.3.10.2 NON-SELECTIVE (ACCB ONLY)

WITHOUT NBS

If no DCCB is installed, all faults (except perhaps DMR-G faults) will require opening of all ACCBs on the affected pole. This in turn implies 50% loss of transmission capacity in case of P-G or N-G faults and 100% loss in case of P-G and P-N-G faults. Figure 49 demonstrates conventional fault clearing by ACCBs. The ACCBs are activated when a converter is tripped (> 4 kA arm current) and take 60 ms to open. A solid P-G fault is applied on the Dutch end of cable 24 (close to bus 4) at 2.5 s. MMCs 3 and 4 operate at full power prior to the fault as this results in highest pre-fault current. The key conclusions are:

- The faults results in tripping of positive poles at all four terminals, and no tripping of negatives poles.
- Negative pole voltage is fairly stable throughout the fault.
- The onshore AC grids act like voltage sources and continue to feed the fault even after the converters block. The DC fault current at the instance of ACCB opening is considerably higher at MMCs 1 and 3 than MMCs 2 and 4.
- The offshore AC grids act like current sources and have limited fault current contribution. In fact, DC fault current declines following the converter blocking because the wind farms limit the current infeed.
Fault current decay at the offshore terminals is much faster than at the onshore terminals. This is caused predominantly by two factors: lower current at the instance of ACCB opening and greater proximity to the fault, which entails reduced inductance of the fault loop.

Offshore terminals are quick to recover from the fault. The power flow through the negative pole is re-established within 150 ms.

Onshore terminals take approximately 400 ms to recover from the fault. During the post-fault recovery, the declining DC fault currents are superimposed on the load currents provided by MMCs 2 and 4.

Cable 24 current (measured at bus 4) is very high and reaches almost 25 kA.
Figure 49 – DC voltages and currents for a P-G fault at cable 24 (close to bus 4), non—selective clearing with ACCBs
The grid behaves as expected and demonstrates an acceptable level of robustness. The wind power on the blocked pole is curtailed by the voltage droop control (chopper). The final measurements are given in Table 30. Figure 50 shows steady-state voltages and current at terminals 2 and 4 in the case where NBS are not operated. Both the negative pole and DMR voltages oscillate due to capacitor switching and MMC harmonics. Since the negative pole is operational, there is large current through DMR, and this implies few kV voltage on DMR. DMR voltage will be either positive or negative, depending on the location and current direction. If DMR voltage is positive it will cause forward voltage on diodes on blocked MMC on positive pole and the MMC will conduct. Similarly, for N-G faults, if DMR voltage is negative it will cause current flow in the negative pole blocked MMC. The arm inductances act like low-pass filters for the current, which attain the average value of 50 A at MMC 2 and 180 A at MMC 4.

![Graph](image-url)
The comparable currents and voltages of MMCs 1 and 3 are shown in Figure 51. The average DMR-to-positive pole voltage is negative at these terminals, because the current on the non-faulted pole is negative. The average DC current is less than 1 A, and is a product of the arm inductor discharge.

<table>
<thead>
<tr>
<th>Pole</th>
<th>I1</th>
<th>V1</th>
<th>I2</th>
<th>V2</th>
<th>I3</th>
<th>V3</th>
<th>I4</th>
<th>V4</th>
<th>I42</th>
<th>V42</th>
</tr>
</thead>
<tbody>
<tr>
<td>Positive</td>
<td>0.001</td>
<td>-0.4</td>
<td>0.048</td>
<td>-0.1</td>
<td>0.001</td>
<td>0.0</td>
<td>0.185</td>
<td>0.0</td>
<td>0.037</td>
<td>0.0</td>
</tr>
<tr>
<td>DMR</td>
<td>-1.726</td>
<td>-1.8</td>
<td>1.678</td>
<td>-0.2</td>
<td>-1.771</td>
<td>-3.3</td>
<td>1.826</td>
<td>-0.0</td>
<td>0.047</td>
<td>-0.0</td>
</tr>
<tr>
<td>Negative</td>
<td>1.732</td>
<td>-528.8</td>
<td>-1.677</td>
<td>-530.1</td>
<td>1.777</td>
<td>-527.5</td>
<td>-1.854</td>
<td>-530.0</td>
<td>-0.068</td>
<td>-530.0</td>
</tr>
</tbody>
</table>

Figure 51 – DC currents and voltages at the positive pole of MMCs 1 and 3 following fault clearing, assuming no NBS

Table 30 – Final measurements at all terminals and cable 24 for a P-G fault on cable 24, cleared by ACCBs only
WITH NBS OPERATING

The above test is repeated with NBS operation, and the NBS current and energy absorption are shown in Figure 52. It is important to notice that the DMR current of offshore MMCs in Figure 49 changes direction during the fault transient. While the current direction reversal cannot occur in the blocked MMC (diodes prevent this), the NBS current naturally touches zero before rebounding back (as proven in Figure 50. The NBS therefore opens under near-zero current conditions, which results in negligible arrester energy absorption.

![Diagram](image)

**Figure 52 – NBS current and energy absorption at the positive pole of MMC 4**

The final measurements for a combined ACCB and NBS fault clearing are given in Table 31. The positive pole current is zero at all terminals, which indicates correct NBS operation.

<table>
<thead>
<tr>
<th>Pole</th>
<th>I1</th>
<th>V1</th>
<th>I2</th>
<th>V2</th>
<th>I3</th>
<th>V3</th>
<th>I4</th>
<th>V4</th>
<th>I42</th>
<th>V42</th>
</tr>
</thead>
<tbody>
<tr>
<td>Positive</td>
<td>0.000</td>
<td>0.0</td>
<td>0.000</td>
<td>0.0</td>
<td>0.000</td>
<td>0.0</td>
<td>0.000</td>
<td>0.0</td>
<td>0.001</td>
<td>0.0</td>
</tr>
<tr>
<td>DMR</td>
<td>-1.724</td>
<td>-1.3</td>
<td>1.677</td>
<td>0.0</td>
<td>-1.774</td>
<td>-2.6</td>
<td>1.860</td>
<td>0.0</td>
<td>0.038</td>
<td>0.0</td>
</tr>
<tr>
<td>Negative</td>
<td>1.730</td>
<td>-528.8</td>
<td>-1.870</td>
<td>-530.1</td>
<td>1.781</td>
<td>-527.4</td>
<td>-1.854</td>
<td>-530.1</td>
<td>-0.066</td>
<td>-530.1</td>
</tr>
</tbody>
</table>
In all of the simulated fault scenarios, it was observed that the DMR fault-feeding starts several hundred milliseconds after the fault is cleared, when the grid settles into the new steady state. Prior to that, the NBS current stays very close to zero (as shown in Figure 52), and this provides plenty of the time for the NBS to open under very low current. The NBS could, in theory, be implemented as a simple DC disconnector (RCB) rather than a passive-resonant DCCB. However, the DCCB implementation provides better reliability because the disconnector may not be able to break the steady-state current if it misses the zero crossing or the opening is delayed for any reason.

3.3.10.3 PARTIALLY-SELECTIVE (DCCB ON CABLE 24)

This section demonstrates the operation of a partially-selective protection strategy where a DCCB is installed on cable 24, on the Dutch offshore platform. The NBSs operate for all faults for this point onwards.

Due to space constraints, arm currents are omitted from Figure 54 and all subsequent figures in this section. However, arm current monitoring is important since the MMC self-protection blocks on 4 kA arm current. The research in [30] shows that the increase in arm current during the first few milliseconds after fault inception is primarily attributed to the MMC’s submodule discharge, and equal to one third of the DC fault current increase. Knowing that the peak pre-fault arm current $I_{arm0}$ for all four MMCs in the grid is around 2 kA, and that the rated DC load current $I_{DC0}$ is 1.9 and 1.7 kA for the Dutch and the British side respectively, the peak arm current $I_{arm, pk}$ can be estimated from any terminal’s DC fault current peak $I_{DC, pk}$ as

$$I_{arm, pk} = \frac{I_{DC, pk} - I_{DC0}}{3} + I_{arm0} = \frac{I_{DC, pk}}{3} + 1.4 \text{ kA}$$  \hspace{1cm} (20)

The arm current blocking threshold is set to 4 kA. Solving (20) when $I_{arm, pk} = 4 \text{ kA}$ yields the approximate DC current limit at which the MMC blocks:

$$I_{DC, blk} = 3 \left( I_{arm, pk} - 1.4 \text{ kA} \right) = 7.8 \text{ kA}$$  \hspace{1cm} (21)

The equations (20) and (21) provide a practical way of estimating the converter’s proximity to blocking in the following subsections. The actual DC current at which the blocking occurs will vary based on the pre-fault power flow and the amount of reactive power the converter is consuming or providing to the AC system. A more detailed insight into the converter’s arm current is given in sections 0 and 0, where the actual arm current measurements are shown for MMCs 3 and 4, under both temporary and permanent (avoided) blocking.

BUS 1 P-G FAULT

Figure 53 shows the responses for a solid P-G fault on cable 12, in proximity of bus 1. DCCB opening time is set to 3 ms while a 100 mH inductor is installed on each pole. The final measurements are provide in Table 32. The key conclusions are:

- Fault is cleared using DCCB 42 and ACCBs 1 and 2.
- Positive poles of the British MMCs block, while the blocking is avoided on the Dutch side (The peak DC current in MMC4 is around 5kA).
- It takes around 300 ms for MMCs 3 and 4 to recover from the transient, although some low-frequency oscillations require longer to die out.
- DCCB current peaks at 9 kA on the positive pole. The fault is neutralized on the rising edge of the current.
- Dutch side continues operating at 100% capacity, while the British side is reduced to 50%.
It is noticed that there is unbalanced operation on Duch side after the fault: current on positive pole at terminal 3 is larger than negative current ($I_{3DMR}=60A$). This is result of disconnection of positive pole on the interconnector cable 24.

A close-up of the main breaker variables for the same test case is shown in Figure 54. The variables for the positive pole are highlighted, indicating the DCCB current, voltage across the main breaker and the absorbed arrester energy. Breaker TIV is 755 kV or 1.438 p.u., which is realistic assuming that the breaker is rated for 16 kA and rated TIV is 1.5 p.u. Because the fault is located far from the breaker, the voltage and current oscillations caused by the traveling waves are considerable.

Table 32 – Final measurements at all terminals and cable 24 for a P-G fault on cable 12, cleared by a 3 ms DCCB

<table>
<thead>
<tr>
<th>Pole</th>
<th>I1</th>
<th>V1</th>
<th>I2</th>
<th>V2</th>
<th>I3</th>
<th>V3</th>
<th>I4</th>
<th>V4</th>
<th>I42</th>
<th>V42</th>
</tr>
</thead>
<tbody>
<tr>
<td>Positive</td>
<td>0.000</td>
<td>0.0</td>
<td>0.000</td>
<td>0.0</td>
<td>-1.852</td>
<td>524.9</td>
<td>1.859</td>
<td>527.3</td>
<td>0.000</td>
<td>0.0</td>
</tr>
<tr>
<td>DMR</td>
<td>-1.731</td>
<td>-1.1</td>
<td>1.693</td>
<td>0.0</td>
<td>0.060</td>
<td>-0.2</td>
<td>0.009</td>
<td>0.0</td>
<td>0.044</td>
<td>0.0</td>
</tr>
<tr>
<td>Negative</td>
<td>1.737</td>
<td>-526.0</td>
<td>-1.686</td>
<td>-527.5</td>
<td>1.792</td>
<td>-524.8</td>
<td>-1.868</td>
<td>-527.4</td>
<td>-0.065</td>
<td>-527.3</td>
</tr>
</tbody>
</table>
Figure 53 – DC voltages and currents for a P-G fault near bus 1, partially-selective clearing
CABLE 24 FAULT (NEAR BUS 4)

Figure 55 shows the responses for a solid P-G fault on cable 24, in proximity of bus 4. This is the same fault which was analysed in section 3.3.10.2. DCCB opening time and inductance are maintained at 3 ms and 100 mH. The responses are similar to Figure 53. Despite the proximity of the fault to MMC 4, the blocking is avoided (peak MMC4 DC current is around 5.7kA) because the DCCB neutralizes the current on the rising edge. Final measurements are given in Table 33.

Table 33 – Final measurements at all terminals and cable 24 for a P-G fault on cable 24, cleared by a 3 ms DCCB

<table>
<thead>
<tr>
<th>Pole</th>
<th>I1</th>
<th>V1</th>
<th>I2</th>
<th>V2</th>
<th>I3</th>
<th>V3</th>
<th>I4</th>
<th>V4</th>
<th>I42</th>
<th>V42</th>
</tr>
</thead>
<tbody>
<tr>
<td>Positive</td>
<td>0.000</td>
<td>0.0</td>
<td>0.000</td>
<td>0.0</td>
<td>-1.852</td>
<td>524.9</td>
<td>1.866</td>
<td>527.4</td>
<td>0.000</td>
<td>0.0</td>
</tr>
<tr>
<td>DMR</td>
<td>-1.730</td>
<td>-1.1</td>
<td>1.687</td>
<td>-0.1</td>
<td>0.061</td>
<td>-0.2</td>
<td>-0.002</td>
<td>0.0</td>
<td>0.041</td>
<td>0.0</td>
</tr>
<tr>
<td>Negative</td>
<td>1.737</td>
<td>-526.0</td>
<td>-1.680</td>
<td>-527.5</td>
<td>1.791</td>
<td>-524.9</td>
<td>-1.864</td>
<td>-527.5</td>
<td>-0.067</td>
<td>-527.4</td>
</tr>
</tbody>
</table>
Figure 55 – DC voltages and currents for a P-G fault on cable 24 (near bus 4), partially-selective clearing
DCCB 42 variables are shown in Figure 56. Peak DCCB current is 10.9 kA, TIV is 777 kV (1.48 p.u.) while the absorbed energy is 11.6 MJ.

Figure 56 – DCCB 42 variables for a DC fault on cable 42 (near bus 4)

Figure 57 shows the response to the same fault when a slower 8 ms DCCB is used, with final values given in Table 34. The DCGB does not neutralize the fault quickly enough to prevent MMC blocking on the Dutch side, and MMCs 3 and 4 also block. A residual voltage of 95 kV remains on the positive pole on the Dutch side, which is a product of the energy stored in MMC’s submodules. This example demonstrates that converter blocking can only be avoided if the DCCB opening time is short, or if the DCCB reactor is large enough to sufficiently reduce the fault current slope. Peak DCCB current in this case is 12.4 kA, TIV is 778 kV and absorbed energy is 37 MJ.

Table 34 – Final measurements at all terminals and cable 24 for a P-G fault on cable 24, cleared by a 8 ms DCCB

<table>
<thead>
<tr>
<th>Pole</th>
<th>I1</th>
<th>V1</th>
<th>I2</th>
<th>V2</th>
<th>I3</th>
<th>V3</th>
<th>I4</th>
<th>V4</th>
<th>I42</th>
<th>V42</th>
</tr>
</thead>
<tbody>
<tr>
<td>Positive</td>
<td>0.000</td>
<td>0.0</td>
<td>0.000</td>
<td>0.0</td>
<td>0.000</td>
<td>94.8</td>
<td>0.000</td>
<td>94.8</td>
<td>0.000</td>
<td>0.0</td>
</tr>
<tr>
<td>DMR</td>
<td>-1.724</td>
<td>-1.2</td>
<td>1.683</td>
<td>0.0</td>
<td>-1.774</td>
<td>-2.5</td>
<td>1.863</td>
<td>0.0</td>
<td>0.039</td>
<td>0.0</td>
</tr>
<tr>
<td>Negative</td>
<td>1.731</td>
<td>-528.5</td>
<td>-1.676</td>
<td>-530.0</td>
<td>1.781</td>
<td>-527.6</td>
<td>-1.856</td>
<td>-530.1</td>
<td>-0.067</td>
<td>-530.1</td>
</tr>
</tbody>
</table>
Figure 57 - DC voltages and currents for a P-G fault on cable 24 (near bus 1), partially-selective clearing with 8 ms DCCB
CABLE 34 FAULT (NEAR BUS 4) – BIDIRECTIONAL DCCB

Figure 58 shows the responses for a solid N-G fault on cable 34, in proximity of bus 4. Bidirectional DCCB is employed, with 3 ms opening time and a 100 mH inductor. The key conclusions are:

- Fault is cleared using DCCB 42 and ACCBs 3 and 4.
- DCCB 42 cannot prevent the blocking of MMCs 3 and 4 because the fault is located on the Dutch side. However, it successfully prevents the blocking of MMCs 1 and 2.
- It takes around 200 ms for MMCs 1 and 2 to recover from the transient, with some low-frequency oscillations taking longer to die out.
- British side continues operating at 100% capacity. Dutch side is reduced to 50% with only the positive pole operational.

The main breaker variables are shown in Figure 59. Peak current is 9.9 kA, peak TIV is -768 kV and the absorbed energy is 9.5 MJ.

The final measurements are provided in Table 35. It is observed that the pole voltages on the British side are not balanced, and this drives a considerable current through the DMR. The problem arises because of the loss of the voltage-regulating MMC 3’s negative pole, as the MMC 1’s voltage droop controller is inadequate to efficiently re-adjust the pole voltage. This mode of operation may also cause instability, because MMC 2 cannot contribute to DC voltage regulation in any way.

Table 35 – Final measurements at all terminals and cable 24 for a N-G fault on cable 34, cleared by a 3 ms DCCB

<table>
<thead>
<tr>
<th>Pole</th>
<th>I1</th>
<th>V1</th>
<th>I2</th>
<th>V2</th>
<th>I3</th>
<th>V3</th>
<th>I4</th>
<th>V4</th>
<th>I42</th>
<th>V42</th>
</tr>
</thead>
<tbody>
<tr>
<td>Positive</td>
<td>-1.681</td>
<td>529.3</td>
<td>1.670</td>
<td>529.2</td>
<td>-1.789</td>
<td>527.5</td>
<td>1.863</td>
<td>529.8</td>
<td>0.065</td>
<td>529.0</td>
</tr>
<tr>
<td>DMR</td>
<td>-0.267</td>
<td>2.6</td>
<td>0.426</td>
<td>-0.5</td>
<td>1.783</td>
<td>2.6</td>
<td>-1.869</td>
<td>-0.1</td>
<td>0.014</td>
<td>-0.1</td>
</tr>
<tr>
<td>Negative</td>
<td>1.944</td>
<td>-415.1</td>
<td>-2.101</td>
<td>-411.5</td>
<td>0.000</td>
<td>0.0</td>
<td>0.000</td>
<td>0.0</td>
<td>0.000</td>
<td>-411.4</td>
</tr>
</tbody>
</table>

The issue can be alleviated by setting the MMC 1’s negative pole to voltage control mode following the fault clearing. This produces the results in Table 36 for the same fault, and it is visible that the negative pole voltage is now regulated at 1 p.u. Nevertheless, this solution is not perfect and still results in small DMR current. This occurs because the positive and negative pole voltages are not balanced, since the voltage of the positive pole is regulated at 1 p.u. at terminal 3.

If it is desired to eliminate the DMR current, the voltage reference for the negative pole of MMC 1 would need to be adjusted to match the voltage of the positive pole. This can be achieved by adjusting the voltage reference to MMC 1, or by designating terminal 1 as the slack bus (voltage control on both poles) and switching MMC 3 over to the power control mode. Both solutions have their benefits and drawbacks, but these will not be discussed further as the topic is out of the scope of this report.

Table 36 – Final measurements for a N-G fault on cable 34, with post-fault voltage control on the MMC 1’s negative pole

<table>
<thead>
<tr>
<th>Pole</th>
<th>I1</th>
<th>V1</th>
<th>I2</th>
<th>V2</th>
<th>I3</th>
<th>V3</th>
<th>I4</th>
<th>V4</th>
<th>I42</th>
<th>V42</th>
</tr>
</thead>
<tbody>
<tr>
<td>Positive</td>
<td>-1.633</td>
<td>533.8</td>
<td>1.625</td>
<td>535.1</td>
<td>-1.760</td>
<td>531.9</td>
<td>1.792</td>
<td>535.2</td>
<td>0.021</td>
<td>534.7</td>
</tr>
<tr>
<td>DMR</td>
<td>-0.063</td>
<td>-0.4</td>
<td>0.075</td>
<td>-0.1</td>
<td>1.753</td>
<td>3.1</td>
<td>-1.799</td>
<td>0.0</td>
<td>-0.017</td>
<td>0.0</td>
</tr>
<tr>
<td>Negative</td>
<td>1.696</td>
<td>-523.6</td>
<td>-1.700</td>
<td>-524.9</td>
<td>0.000</td>
<td>0.1</td>
<td>0.000</td>
<td>0.0</td>
<td>0.000</td>
<td>-525.0</td>
</tr>
</tbody>
</table>
Figure 58 – DC voltages and currents for a N-G fault on cable 34 (near bus 4), partially-selective clearing.
CABLE 34 FAULT (NEAR BUS 4) – UNIDIRECTIONAL DCCB

The test from the previous section is repeated with a unidirectional DCCB, which cannot break reverse current. In this case the fault has to be cleared by ACCBs, and both the British and the Dutch side lose power transfer capacity on the negative pole. The grid voltages and currents are shown in Figure 60, and the reverse (diode) DCCB current is clearly visible. The final measurements are provided in Table 37.

Table 37 – Final measurements at all terminals and cable 24 for a N-G fault on cable 34, with a unidirectional DCCB

<table>
<thead>
<tr>
<th>Pole</th>
<th>I1</th>
<th>V1</th>
<th>I2</th>
<th>V2</th>
<th>I3</th>
<th>V3</th>
<th>I4</th>
<th>V4</th>
<th>I42</th>
<th>V42</th>
</tr>
</thead>
<tbody>
<tr>
<td>Positive</td>
<td>-1.728</td>
<td>528.2</td>
<td>1.673</td>
<td>529.8</td>
<td>-1.781</td>
<td>527.3</td>
<td>1.856</td>
<td>529.7</td>
<td>0.066</td>
<td>529.8</td>
</tr>
<tr>
<td>DMR</td>
<td>1.722</td>
<td>1.3</td>
<td>-1.680</td>
<td>-0.1</td>
<td>1.774</td>
<td>2.5</td>
<td>-1.863</td>
<td>0.0</td>
<td>-0.041</td>
<td>0.0</td>
</tr>
<tr>
<td>Negative</td>
<td>0.000</td>
<td>0.0</td>
<td>0.000</td>
<td>0.0</td>
<td>0.000</td>
<td>0.0</td>
<td>0.000</td>
<td>0.0</td>
<td>0.001</td>
<td>0.0</td>
</tr>
</tbody>
</table>
Figure 60 - DC voltages and currents for a N-G fault on cable 34 (near bus 4), for a unidirectional DCCB
3.3.10.4 DCCB SPECIFICATIONS

DCCB INDUCTANCE FOR AVOIDING MMC BLOCKING

One of the goals of this study is determining the minimal DCCB inductor size which prevents blocking of the Dutch offshore converter under DC faults in protection zone 1 (cables 12 and 24). A full range of 5 fault types was applied at three locations in zone 1:

- Cable 12, in proximity of bus 1
- Cable 12, 30 km from bus 2
- Cable 24, in proximity of bus 4

The DCCB opening time and inductor size were varied, and the state of MMC 4 was being monitored. The power output of the offshore wind farms was set to 1 p.u., as this results in the highest pre-fault MMC 4 current. Three important conclusions were reached during these tests:

- P-G, P-N, P-N and P-N-G faults all result in very similar fault current waveforms on the affected poles, and the difference in peak DCCB current, TIV and energy absorption is minimal. Studying only one fault type can provide all the relevant information for DCCB dimensioning while reducing the number of cases by 75%.
- The worst-case fault location for MMC 4 blocking is a fault on cable 24, in close proximity to the converter. Since this fault type effectively decouples the UK and NL side, the power rating of the UK side plays no role in the fault transient on the NL side. Therefore, the presented results are valid for both the 900 MW and 600 MW UK converter ratings.
- Preventing MMC 4 blocking also implies avoiding MMC 3 blocking. Because of a radial grid layout, any fault transient originating from zone 1 must pass by MMC 4 before reaching MMC 3. MMC 4 is always closer to the fault origin, and thus affected more severely.

Table 38 shows the minimal inductor size $L_{crit}$ required to prevent MMC 4 blocking for each of the considered DCCB opening times. The peak DCCB current, TIV and energy absorption are also provided, but it should be noted that these values are not necessarily the overall peaks, since the pre-fault current through the interconnector cable is zero. The absolute peaks for DCCB dimensioning are provided in section 0.

<table>
<thead>
<tr>
<th>DCCB opening time</th>
<th>$L_{crit}$</th>
<th>Peak DCCB current</th>
<th>Peak TIV</th>
<th>Absorbed DCCB energy</th>
</tr>
</thead>
<tbody>
<tr>
<td>3 ms</td>
<td>70 mH</td>
<td>13.4 kA</td>
<td>782 kV</td>
<td>12.6 MJ</td>
</tr>
<tr>
<td>5 ms</td>
<td>200 mH</td>
<td>9.1 kA</td>
<td>762 kV</td>
<td>17.7 MJ</td>
</tr>
<tr>
<td>8 ms</td>
<td>380 mH</td>
<td>7.8 kA</td>
<td>745 kV</td>
<td>32.3 MJ</td>
</tr>
</tbody>
</table>

Test results show that continuous MMC operation can be achieved with reasonably sized inductors, even if slower mechanical DCCBs are used. The relationship between the inductor size and DCCB opening time is not linear, and slower DCCBs require much higher inductance to prevent converter blocking. On the other hand, the absorbed DCCB energy is somewhat proportional to the opening time in this dataset. In practice, some margin would be required and the employed inductances would be higher than those in Table 38.

The benefits of avoiding MMC blocking are demonstrated in Figure 61, which shows MMC 4 variables for a cable 24 fault, using a 8 ms DCCB with a 380 mH inductor. Despite the long breaker opening time and a considerable
DC voltage dip, the impact on the offshore AC system variables is limited. There is only a small reduction in the RMS voltage, in the first 50 ms following the fault, which means that the OWF stays connected to the grid. The increase in fault current contribution from the OWF is also very limited. MMC blocking is avoided only marginally, and two arm currents reach very close to the 4 kA blocking threshold.
Figure 61 - MMC 4 variables for avoided blocking with a 8 ms DCCB, Ldc=380mH.
The onshore MMC 3 variables for the same test case are shown in Figure 62. The pre-fault current is negative, and the power is exported to the onshore AC grid. A DC fault reverses the current direction and the power flow, and the AC current magnitude initially decreases for that reason. Meanwhile, the AC voltage at the PCC is very stable, and no apparent disturbance is noticeable. The arm current has a negative pre-fault DC component and peaks at 1.6 kA, which is very far from the overcurrent blocking threshold.

A comparison between the MMC 3 and 4 variables reveals that the DC-side response of both converters is very similar, but the impact on the AC grid is very different. An offshore converter operates in the grid-making mode, and a sudden change in DC voltage facilitates a change in the AC voltage magnitude. Meanwhile, the AC current is stable because the OWFs provide constant power. The opposite occurs at the grid-following onshore MMC, where the strong onshore grid provides firm AC voltage but the AC current magnitude changes considerably. A study in [31] reveals that the AC current magnitude change is primarily caused by the change in the pre-fault power-flow direction, and it makes little difference that the MMC 3 is connected to a strong AC voltage source. In general, inverters are more likely to experience a significant AC current disturbance during DC faults than rectifiers [31]. On the other hand, the inverters are far less prone to blocking, since their average pre-fault arm current is negative.
Figure 62 - MMC 3 variables for avoided blocking with a 8 ms DCCB
DESIGN ASSUMING TEMPORARY MMC BLOCKING

An alternative approach to ensuring MMC fault ride-through is by employing temporary MMC blocking, which is studied in detail in [31]. The blocking threshold is set to 4 kA for all MMCs, since their rated arm current is close to 2 kA. The 10% difference in power rating between Dutch and British MMCs does not warrant utilizing different overcurrent protection settings because it is highly likely that the IGBTs in both will be rated for the same current. The de-blocking threshold is set to 2.4 kA (1.2 p.u.). ACCB opening is suspended for 20 ms following the MMC blocking, and the blocking becomes permanent (ACCB tripped) if the arm current does not dip below 2.4 kA within that period. Only the overcurrent self-protection is considered in this study, but other methods are also feasible (undervoltage, overtemperature etc.).

Figure 63 shows MMC 4 variables before, during and after temporary blocking. A P-G fault is applied on cable 24, while the DCCB opening time is 8 ms (worst case DC CB) with a 100 mH inductor. These are the same test conditions as in Figure 57. Both the AC and DC currents are shown, as well as the blocking signal. The AC variables are shown only for the positive pole which experiences blocking.

MMC 4 is blocked for only 8 ms, which is less than one half of the grid period. Blocking collapses the DC voltage on the affected pole, causing an instantaneous (but temporary) reduction in DC fault current. The AC voltage also collapses, but recovers very quickly once the converter is de-blocked. This is because converter submodules retain their charge while blocked. According to ENTSO-E codes for offshore wind-park connection to HVDC systems, the AC voltage must start to recover within 250 ms [32] following a DC fault. The demonstrated temporary blocking strategy clearly complies with this requirement.

MMC 3 variables for the same fault are shown in Figure 64. Similarly to the responses for the avoided blocking, the AC voltage at the PCC is very stable, although a small discontinuity in the waveform is observed at the instance of MMC blocking. The AC current magnitude initially decreases as a consequence of the power flow reversal. On the other hand, the arm current is very high and exceeds 3 p.u., but it also diminishes quickly as the DC fault is neutralized and the DC voltage recovers. MMC 3 is blocked for even shorter than MMC 4, and the post-fault recovery is quick.

When temporary blocking is employed, DCCB inductor needs to be dimensioned solely based on its breaking capacity. Table 39 shows the minimum inductor sizes which prevent DCCB current from exceeding 16 kA when temporary blocking is employed. The inductances are rounded up to the nearest 10 mH.

<table>
<thead>
<tr>
<th>DCCB opening time</th>
<th>$L_{dc}$</th>
<th>Peak DCCB current</th>
<th>Peak TIV</th>
<th>Absorbed DCCB energy</th>
</tr>
</thead>
<tbody>
<tr>
<td>3 ms</td>
<td>60 mH</td>
<td>15.8 kA</td>
<td>787 kV</td>
<td>14.9 MJ</td>
</tr>
<tr>
<td>5 ms</td>
<td>70 mH</td>
<td>15.9 kA</td>
<td>787 kV</td>
<td>18.0 MJ</td>
</tr>
<tr>
<td>8 ms</td>
<td>90 mH</td>
<td>15.8 kA</td>
<td>787 kV</td>
<td>27.7 MJ</td>
</tr>
</tbody>
</table>

As before, cable 24 fault is identified as the most severe, resulting in the greatest fault current increase, and this means that the UK converter power ratings have no impact on the fault transient on the NL side. However, unlike in section 0, the worst-case scenario for temporary MMC blocking (from the inductor dimensioning perspective) is when the interconnector is operational and the maximum amount of power is transferred from the Dutch to the
British side. The pre-fault current depends on the UK HVDC power rating, and the difference between the 900 and 600 MW cases is 571 A. The 900 MW case is clearly more severe and therefore selected as relevant, but the differences in obtained inductor sizes are minimal compared to the 600 MW case, given that 571 A accounts for merely 3.6% of the DCCB current rating.

Several observations are made when comparing the results with Table 38:

- Preventing MMC blocking requires considerably higher DCCB inductance, particularly for slower DCCBs. The inductances in Table 39 are quite reasonable for all DC CB topologies (60 mH – 90 mH).
- DCCB opening time has far lower impact on the inductor sizing if MMC blocking is employed, as opposed to when blocking is avoided. An 8 ms DCCB requires only a 50% larger inductor than a 3 ms DCCB in the former case, and 443% larger inductor in the latter case.
- DCCB energy absorption is higher in two out of three cases (3 and 5 ms) with temporary blocking compared to no blocking, but the energy absorptions are not significantly different. The reduction in reactor size is counteracted by an increase in peak DCCB current.
Figure 63 – MMC 4 variables for temporary blocking with a 8 ms DCCB
Figure 64 – MMC 3 variables for temporary blocking with a 8 ms DCCB
REQUIRED DCCB RATINGS

This section estimates the current, voltage and energy ratings of a DCCB on cable 24. A comprehensive simulation study was undertaken, studying different fault types, locations, pre-fault power flows, DCCB inductor sizes, DCCB opening times and two possible power ratings of the UK converters. The data points are grouped by the UK-side power rating, DCCB opening time and inductor size (determined by the converter blocking strategy). For each triplet of these parameters, the peak values of monitored variables are selected out of all the associated test cases, where all the other parameters had been varied.

The study considers both the unidirectional and bidirectional DCCB topologies. However, the most severe faults for all triplets are identified to occur in zone 1, which implies positive current direction. This means that the ratings of both the unidirectional and bidirectional breaker are identical, as far as the peak interrupting current and energy are concerned. However, this does not mean that the design principles behind these two topologies are also identical. Unidirectional topologies require additional considerations, which are discussed further below.

The results are summarized in Table 40, which provides a comprehensive overview of the DCCB dimensioning requirements in Ijmuiden Ver. All the ratings are given per pole. The two cases are considered depending on weather temporary blocking is employed or not. The provided inductor sizes are the minimal values required to:

- a) limit DCCB current below 16 kA in the case of temporary blocking strategy, and
- b) avoid blocking of MMC 4, if the conventional permanent blocking strategy is employed.

The main conclusions are:

- UK-side power rating has a limited impact on the DCCB design specifications, but the minimal inductor size and energy absorption are somewhat lower in the 600 MW case.
- When a breaker with a 3 ms opening time is utilized, there is very little difference between DCCB specifications for the two MMC blocking strategies. Assuming a considerable margin will be applied in the practical installation, it can be concluded that MMC blocking will not occur for any faults.
- DCCB energy absorption increases with the DCCB opening time, but the exact relationship greatly depends on the employed blocking strategy. The increase is roughly proportional with permanent blocking and less than proportional with temporary blocking. In the latter case, an increase of 167% in DCCB opening time results in only 86% increase in energy absorption. Blocking the MMCs collapses the DC bus voltage, and reduces the average voltage applied across $L_{dc}$ [31]. Permanent blocking generally implies larger DCCB energy dissipation
- Peak TIV across all cases is 787 kV, which is 1.499 p.u. of 525 kV. This is in line with technical recommendations [20], so the surge arrester selection is sound and realistic.

<table>
<thead>
<tr>
<th>UK power rating</th>
<th>DCCB opening time</th>
<th>MMC blocking strategy</th>
<th>$L_{dc}$</th>
<th>Peak DCCB current</th>
<th>Peak TIV</th>
<th>Absorbed DCCB energy</th>
</tr>
</thead>
<tbody>
<tr>
<td>900 MW</td>
<td>3 ms</td>
<td>Temporary</td>
<td>60 mH</td>
<td>15.8 kA</td>
<td>787 kV</td>
<td>14.9 MJ</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Permanent</td>
<td>70 mH</td>
<td>14.8 kA</td>
<td>785 kV</td>
<td>14.9 MJ</td>
</tr>
<tr>
<td></td>
<td>5 ms</td>
<td>Temporary</td>
<td>70 mH</td>
<td>15.9 kA</td>
<td>787 kV</td>
<td>18.0 MJ</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Permanent</td>
<td>200 mH</td>
<td>10.6 kA</td>
<td>777 kV</td>
<td>24.0 MJ</td>
</tr>
<tr>
<td></td>
<td>8 ms</td>
<td>Temporary</td>
<td>90 mH</td>
<td>15.8 kA</td>
<td>787 kV</td>
<td>27.7 MJ</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Permanent</td>
<td>380 mH</td>
<td>9.3 kA</td>
<td>766 kV</td>
<td>43.8 MJ</td>
</tr>
<tr>
<td>600 MW</td>
<td>3 ms</td>
<td>Temporary</td>
<td>60 mH</td>
<td>15.4 kA</td>
<td>786 kV</td>
<td>13.9 MJ</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Permanent</td>
<td>70 mH</td>
<td>14.4 kA</td>
<td>784 kV</td>
<td>12.5 MJ</td>
</tr>
</tbody>
</table>

Table 40 – Unidirectional and bidirectional DCCB requirements in Ijmuiden Ver
DCCB ratings provided in this section are minimal, and utilize the lowest applicable inductor size. Increasing the inductor size reduces the peak DCCB current, but increases the energy absorption. The optimal inductor size will depend on the exact project specifications, and determining its value is neither in the scope of this report, nor possible at this point in time.

### Study of Reverse Diode Ratings in a Unidirectional DCCB

In addition to the requirements outlined in Table 40, a unidirectional DCCB needs to withstand reverse DC fault current for the duration of ACCB fault clearing for faults occurring in protection zone 2. Table 41 provides the peak reverse current, as well as the reverse $I^2t$ integral for all the examined breaker designs, which is relevant for dimensioning LCS’ antiparallel diodes. All three DCCB opening times are considered for completeness, even though it is understood that only the 3 ms breaker would be of the hybrid type, and therefore possibly unidirectional. It is also understood that permanent MMC blocking will occur in all cases, but Table 41 gives temporary/permanent blocking rows because a temporary blocking strategy can be applied for zone 1 faults, and this will influence the inductor size. The main conclusions are:

- The size of DCCB reactor has limited effect on reducing the reverse fault current peak. This is because the fault clearing by ACCBs takes much longer than the duration of the fault current’s rising edge.
- Despite the reduction in peak current, the $I^2t$ integral is much higher for larger inductors because the current decay is slower.
- For comparable inductor sizes (namely the 70 mH inductor), the $I^2t$ integral is lower when permanent MMC blocking is employed. This is because temporary MMC blocking introduces an additional 20 ms delay in tripping the ACCBs.
- Lower UK power rating reduces the $I^2t$ integral of the reverse breaker current. The reduction is most noticeable for small inductor sizes, and diminishes as the inductors grow larger. This phenomenon is explained by the fact that the DC fault current infeed from the UK side has two components: the capacitive discharge current from the MMC’s submodules and cables, and the rectified AC grid infeed, provided predominantly by the onshore grid. The peak of the capacitive discharge current is limited by the reactor size, and this component is dominant when the reactors are small. Because 600 MW MMCs have greater arm inductance and lower arm capacitance than 900 MW MMCs, the peak discharge current, and therefore the energy that needs to be dissipated post ACCB opening, is notably affected by the MMC power rating. However, when the DCCB reactors are large, rectified AC grid infeed dominates the fault response. The power rating of AC 1 is independent of the MMC 1 power rating, so there is very little difference in the observed responses.

<table>
<thead>
<tr>
<th>UK power rating</th>
<th>DCCB opening time</th>
<th>MMC blocking strategy</th>
<th>$L_{dc}$</th>
<th>Peak diode current</th>
<th>$I^2t$ integral of diode current</th>
</tr>
</thead>
<tbody>
<tr>
<td>900 MW</td>
<td>3 ms</td>
<td>Temporary</td>
<td>60 mH</td>
<td>20.6 kA</td>
<td>2.4e7 A²s</td>
</tr>
</tbody>
</table>
At the time of writing, the datasheets for the press-pack IGBT modules, which will most likely be employed in the LCS and the MB of the HCB, do not provide the maximum $I^2t$ integral for the antiparallel diodes. This parameter is highly variable for the standalone high-power diodes, and can vary between $1e6 \text{ A}^2\text{s}$ to above $40e6 \text{ A}^2\text{s}$. For these reasons, it is not possible to conclude whether the inbuilt antiparallel diodes will be able to withstand the reverse fault current in zone 2, or will additional bypass modules be required. Nevertheless, some observations and implications can be made:

- The LCS will employ a 3x3 IGBT (diode) matrix, while a MB will consist of a single stack of IGBTs. Individual IGBT modules in both will likely be identical, but each antiparallel diode in the LCS will conduct only one third of the surge current. Therefore, all reverse current conduction should occur through the LCS rather than the MB. The LCS also benefits from active cooling.

- Assuming 3 parallel branches in the LCS, the peak diode current from Table 41 needs to be divided by 3 to obtain the current through a single diode. The $I^2t$ integral needs to be divided by 9. This signifies the advantage of parallel IGBT operation, compared to the single-branch MB valve.

- The surge current rating of the antiparallel diodes in [29] (which was used in the LCS losses estimation) is 14 kA. The peak diode current in Table 41 ranges between 16.2 and 20.6 kA. The peak current through a single LCS diode is 6.9 kA, which is well below the diode’s surge current rating. On the other hand, the lowest MB diode current is 16.2 kA, which is higher than the 14 kA limit. It is therefore concluded that the MB will most likely not be able to withstand the reverse fault current, and should be protected at all costs by ensuring the LCS (and the UFD) stay closed during zone 2 faults.
3.4 COST ESTIMATE OF THE DIFFERENT TECHNICAL OPTIONS

For the cost estimate we consider the four technical options as described in the section 3.2 which differ in the type and amount of equipment used for WindConnector between TenneT Ijmuiden Ver and Vattenfall Norfolk Boreas offshore platforms. Note, that bi-directional DC circuit breakers are assumed in cost calculation.

Table 42 Marginal Costs for a WindConnector (above Evacuation Costs and excluding Cable Costs)

<table>
<thead>
<tr>
<th>Equipment Investment Costs</th>
<th>OPTION 1 Total cost (€ mln)</th>
<th>OPTION 2 Total cost (€ mln)</th>
<th>OPTION 3 Total cost (€ mln)</th>
<th>OPTION 4 Total cost (€ mln)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Number</td>
<td>Cost</td>
<td>Low</td>
<td>High</td>
</tr>
<tr>
<td>DC disconnectors (4 in total),</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
</tr>
<tr>
<td>Earthing switches (8 in total),</td>
<td>8</td>
<td>12</td>
<td>8</td>
<td>8</td>
</tr>
<tr>
<td>Surge arresters (4 in total),</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
</tr>
<tr>
<td>Zero-flux CTs (4 in total),</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
</tr>
<tr>
<td>DC cable terminations (4 in total),</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
</tr>
<tr>
<td>Extension of DC busbars,</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>HSS's in total (one per cable pole end),</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
</tr>
<tr>
<td>DC-side pre-insertion resistor units (2 per platform) with their own bypass HSS's,</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>Discharge resistor units along with their own HSS to enable fast discharge process of interconnecting DC cable section,</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sub-Total Equipment Costs</td>
<td>€ 3.00</td>
<td>€ 5.00</td>
<td>€ 4.00</td>
<td>€ 6.00</td>
</tr>
<tr>
<td>HVDC Circuit Breakers</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mechanical Investment</td>
<td>4</td>
<td>2.70</td>
<td>10.80</td>
<td>4</td>
</tr>
<tr>
<td>Operating Costs over lifetime Sub-Total</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hybrid Investment</td>
<td>4</td>
<td>14.00</td>
<td>56.00</td>
<td>4</td>
</tr>
<tr>
<td>Operating Costs over lifetime Sub-Total</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sub-Total HVDC Circuit Breaker Costs</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Additional Platform Space</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Minimum Space requirement</td>
<td>m³</td>
<td>€ 5.00</td>
<td>€ 10.00</td>
<td>m³</td>
</tr>
<tr>
<td>Maximum space requirement</td>
<td>5,000</td>
<td>8,000</td>
<td>7,000</td>
<td>10,000</td>
</tr>
<tr>
<td>Sub-Total Additional Platform Space</td>
<td>€ 5.00</td>
<td>€ 10.00</td>
<td>€ 6.00</td>
<td>€ 12.00</td>
</tr>
<tr>
<td>TOTAL LIFETIME INVESTMENT</td>
<td>€ 8.00</td>
<td>€ 15.00</td>
<td>€ 10.00</td>
<td>€ 18.00</td>
</tr>
<tr>
<td>SOCIAL BENEFITS</td>
<td></td>
<td></td>
<td></td>
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<td>Costs associated with Reengineering Platforms Simultaneously</td>
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<td>Option 3 vs Option 2</td>
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<td>TOTAL SOCIAL BENEFITS</td>
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<td>TOTAL INVESTMENT</td>
<td>€ 5.98</td>
<td>€ 9.30</td>
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In Table 42, the initial cost benefit indicates that the cost of DC Circuit Breakers is not economically viable. DC Circuit Breakers will only be used if there is a contractual reason that makes it necessary or there is some form
of financial support related to demonstration of technical progress. Given the overall cost of such a link, the amounts are relatively small. However, for subsidy this may represent a material sum of capital.

Notes on Table 42:

- Costs and bills of material are approximate and based on estimates from various sources across PROMOTioN.
- Costs of Circuit Breakers derive from the WP12 Cost Data Collection document which has bottom up calculations of the equipment.
- This analysis is prepared for a scenario where the additional equipment would be placed on a TenneT platform. Other options exist to split the equipment between the TenneT platform and the Vattenfall platform, or to have a second ancillary platform to house the protection equipment.
- One of the main costs of the project is the requirement for additional space on the offshore platform to locate the HVDC CBs. At present, this, and the type of HVDC CBs present large and risky uncertainties. Hence there is a large cost assigned.
- The Social Benefits/cost avoidance is linked to a variety of fault and maintenance factors that lead in each step to higher benefit or cost avoidance (lower down time for maintenance, fewer losses, etc.)
- The project already has a large amount of first of a kind technology on board (1st 2 GW underwater cables, 1st 2GW offshore converters, etc.). The perception is at present that there is no need for additional risk, when this risk does not present a suitably positive Cost Benefit. However, a potential contribution from the EU via the CEF may make the project viable, whereby the use of HVDC CBs could go ahead as a first offshore placement of HVDC CBs.
- A significant part of benefits related to the increase in security, avoided conversion losses and increased availability of the link have not been quantified. These might change the outcome of cost-benefit comparison significantly and thus further analysis is recommended.

3.5 LEGAL & REGULATORY BARRIERS AND BIDDING ZONE ARRANGEMENT.

The creation of an interconnector between two EEZs has an important impact on the regulation of electricity trade. Independently of which protection equipment will be employed for the WindConector project, it is interesting to analyse some of the non-technical dimensions. PROMOTioN has supported multiple discussions around the status of subsea cables, bidding zone arrangements, multi-vendor interoperability and procurement. A high-level overview is given in this section.

To date, the UK EEZ and the Dutch EEZ have been treated as an extension of their respective national Bidding Zones. The introduction of a cable connecting two offshore windfarms in different bidding zones, hence combining energy evacuation and interconnection functionality (Hybrid asset), brings this into discussion.

Under Article 16 of Regulation (EU) 2019/943 [15] an interconnector and adjacent infrastructure must have 70% of its capacity available for cross-border flows as stipulated by the market clearing in neighbouring countries. Normally, and under current assumptions, the cable between Ijmuiden Ver and Norfolk is defined as an interconnector. The cables connecting the OWFs to shore are considered as extensions of the onshore grid. These latter cables are scaled to be able to evacuate all offshore wind generation to shore. This means that at peak power, these cables are running at full capacity. The proposed interconnector has a capacity of 1.8 GW (which matches n-1 infeed constraints to the UK Grid as well as the cable dimensions from Norfolk to shore).
Therefore 70% of this should be available for interconnection at all times, i.e. 1.26GW should be free for interconnection. The interconnector is of course, always available for cross-border flows. However there is a structural constraint in the UK and the Dutch grids as when evacuating energy from the wind farms, there is limited capacity for trade, although this infrastructure is also supposed to have 70% of the capacity available for cross-border flows. Each respective TSO would be responsible for solving this constraint.

The options that exist at present are:

1. A Regulatory Exemption for this section of the grid under Art. 63 of CEP Electricity Regulation (2019/943).
2. The creation of new Bidding Zones for either one of or the combination of the two interconnected platforms.
3. Introduction of new legislation for Hybrid assets (not mutually exclusive with 2. Above)

As a part of the evaluation of the different options for the project, TenneT is considering a number of sources including PROMOTioN work done on Market modelling and Bidding Zones arrangement. PROMOTioN has covered the issue of Hybrid Assets extensively in Work Package 7.2, hence it will not be reviewed here. A study comparing various options for offshore bidding zone in relation to how it may affect revenue distribution from energy trading is given in the main Deliverable 12.4. The discussion of Hybrid Assets takes on a very pragmatic illustration of the need for change by reviewing the WindConnector Project.

3.5.1 EXEMPTION

A direct exemption of the 70% ruling is not possible. The exemption will need to be on Third Party Access. The combination of paragraphs c) and e) of Article 63 means that a regulated project is therefore not possible, and a merchant interconnector is required (separate from TSOs in legal terms, costs of the interconnector need to be fully recovered by congestion rent and possibly EU subsidy). For a project to receive an exemption, it is necessary that it fulfills all criteria mentioned in Article 63. This is an established and tried procedure. While it may work where the interconnection is between two countries, such as this, in more complex situations and where more countries are involved this may not be as easy to arrange and it may lead to sub-optimal investment in a meshed grid if investment is based solely on congestion rent, without any regulated income.
3.5.2 CREATION OF NEW BIDDING ZONES

It is suggested that in order to deal with the above-describe issue, the OWFs will not belong to their respective national bidding zones anymore, but will be considered as located in separate offshore bidding zones UK-2 and NL-2. As these bidding zones consist of generation only and wind energy has zero marginal costs, the OWFs will bid-in their available capacity for a low amount, theoretically they can possibly bid at €0 /MWh. After closure of the day-ahead market, the market coupling algorithm will couple the UK-2 and NL-2 zones with NL-1 and/or UK-1, leading to dispatch of the OWFs. In this situation, no priority needs to be given to OWFs as these will almost always be greater than zero (there are possible scenarios where it could go negative).

The configuration however will have effect on price formation. There have been a number of scenarios analysed: no wind generation (the whole system operates as a point to point interconnector and energy flows from high price to low price zone, congestion price is paid); High Wind (Wind flows to home country, price for OWF converges to price at lowest price zone. No congestion rent); Medium Low wind (All Wind takes priority flowing to high price zone at price of low price zone); Medium High Wind (Not all wind can be transported to the high price zone, the interconnector connecting the high price zone to the neighbouring offshore wind bidding zone constitutes the constraint for cross zonal exchange and the price border – hence both offshore wind farms receive the lower price.

In the analysis of different market models we have described this mechanism in detail in the main PROMOTioN Deliverable 12.4. The conclusions are clear that the Social Benefit remains the same, but that however distribution of the proceeds will change. OWFs will receive a smaller share of the proceeds in this model. If OWFs are subsidised this may or may not be compensated, depending on the subsidy design.

A related issue is in the remuneration of the transmission infrastructure. In the situation described, the interconnectors can be either merchant cables or a part of the Regulated Asset Base. As precedent, PROMOTioN has reviewed the current North Sea infrastructure, and observed that NordLink between Norway and the Netherlands is a regulated asset, while BritNed is currently a merchant cable. Therefore, both situations may be
considered. It is assumed that the cable between the Bidding Zones NL-2 and NL-1 will be a part of the regulated asset base. It will therefore be compensated as such. However, the status of the UK-2 to NL-2 cable (the interconnector) may require discussion. The developers wish to consider both situations, given that the business case economics of a congestion payment model may not be sustainable in the longer term.

Lastly, there is the issue of whether cable/transmission losses should be socialised (TSO purchases additional energy than is delivered) or not socialised (the OWF receives money for the sold amount, but needs to deliver more power).

3.5.3 SUMMARY OF IDENTIFIED BARRIERS TO USING HVDC CBS FOR THE WINDCONNECTOR PROJECT

Due to the fact that limited information was made available for WindConnector project, studies that are performed do not cover all potential hurdles that would be experienced when adding DCCB at the offshore platform. Several aspects have been touched upon in this report but a more thorough analysis would be required, which falls out of the PROMOTioN timeline. Nevertheless, within the available period, PROMOTioN has made an overview of various aspects and analysed them utilising more general recommendations obtained within different Work Packages and available technical models, and conducted multiple discussions with project stakeholders.

Below is a range of barriers that have been identified. PROMOTioN recommends further studies on the below aspects as they are deemed to be of the utmost importance if WindConnector is to be realised with HVDC circuit breaker.

1. **Technical**: the integration of a HVDC Circuit Breaker into the base case design of IJVER requires a review and coordination between all control and protection functions. Many technical aspects are expected to remain unknown until a rather late stage, which makes the technical integration a demanding engineering task. Further off-line studies are required and a mock-up (downscaled) grid representation of the complete WindConnector needs to be developed in an independent lab to deliver the full proof-of-concept. This aspect affects Vattenfall equally. **PROMOTioN has performed the dynamic simulation of DC faults on the WindConnector which indicate feasibility and provide initial estimation of the components. However, PROMOTioN does support the follow-up research and has supported the preparation of application for research funding for this. Utilising the partners, who already have experience within PROMOTioN may also support the next steps.**

2. **Procurement**: only few market players offer HVDC CB’s commercially in Europe. As the market is very immature and whole system solutions may not be available in the near-term, this may mean that the DC breakers may need to be purchased as “free-issued material”, which would automatically make TenneT responsible for the overall system integration. TenneT and Vattenfall will in this situation face greater technical challenges and risk with limited resources. If the HVDC CB is to be implemented in-depth knowledge of the DC breaker product and its development steps needs to be in place. Early engagement with the market seems of utmost importance here. There is also a need for suppliers to work together on the realisation of turnkey projects. **This issue is not explicitly covered within PROMOTioN. Albeit the European tendency towards BOT contract is one that requires suppliers to be able to source or supply the full infrastructure. The current view is that turnkey suppliers source all components, but we observe**
that the industry may be de-structuring and re-configuring into focused component producers and integrators. As such, integrators will need to source and accept responsibility for externally supplied components (like a car manufacturer sources components from 3rd parties). This may be a challenge in the early stages, and will require strength of will from the buyers (TSOs, etc.)

3. **Interface management**: The procurement issue highlights a need to clarify the roles of TenneT and the relevant suppliers and to have these explicitly reflected in the contractual arrangements. Technical interfaces and parameters, interface conditions and requirements need to be identified and documented prior to contract award. Liability of the different parties must be agreed. In PROMOTioN Work Package 11 we focus on “Harmonization”. While it is recognised that standards will need to be set by industry umbrella organisations like Cigre and Cenelec, PROMOTioN has initiated a programme to identify gaps in standards and specifications, specifically related to HVDC. We also recognise the need for interoperability. In PROMOTioN, there has been extensive discussion about the ability to connect together equipment from different suppliers. This discussion forms a topic area within Work Package 11. It is seen as important that apparently standard materials and components from different suppliers can operate successfully together. We envisage this as a prerequisite for future development as any grid structure is likely to be built incrementally and thus through a process of sequential procurement processes where different suppliers may be selected. Lastly, in order to connect together HVDC without creating the losses that we try to remove by utilising HVDC there are some overriding choices that do need to be made, such as voltage choice. Attention to all these factors will lead to higher scale for certain choices and thus the opportunity for a manufacturing learning curve, which may be economically attractive.

4. **Planning**: TenneT and Vattenfall have a tight timeline for delivery of the project. The additional engineering time, would bring it into the critical path for planning. Furthermore and as a minimum, 3 more months must be reserved for commissioning time. This aspect affects Vattenfall equally. For this specific project, we dive in to support an existing project and not a planned one. PROMOTioN has, in Work Package 7 justified the need for longer term planning. Longer term identification of OWFs and the potential size of these is becoming (increasingly) necessary to satisfy processes around large stakeholder groups. PROMOTioN believes that it is unrealistic to anticipate a shortening of the consultation period. Also supplier delivery and build lead times for equipment are lengthy. This requires an early definition of what we wish to do. It also facilitates proper consideration of anticipatory investment. This brings with it a couple of caveats: the technology is likely to develop quickly, whereby definition of specification and infrastructure needs to be finalised only late in the process. This may have benefits as well as potential downsides. However, it allows a project to benefit from technical developments. It gives more predictability to the industry – lower risks.

5. **Markets & Bidding Zones**: The discussion above highlights that a decision needs to be made on which route to go with regard to regulating the interconnector asset. The longer term conclusion within PROMOTioN (see D12.4 Chapter 4.5) does migrate towards smaller offshore zones in order to manage EEZ bidding zone imperfections. The proposal of small zones, although a workaround for current
Interconnector Regulation, may be a too big a step for this project and we need to consider also the Exemption route even if this represents a temporary solution. PROMOTioN in Work Package 7 (D12.3 Chapter 4.3 Error! Reference source not found.) recommends the definition of and legal classification of Hybrid assets, which would be the sustainable solution to this issue.

6. **Compensation**: Compensation for the TSO is considered important and is dependent on the status of the assets. As such, it is the view of PROMOTioN that the creation of a Hybrid Asset classification may need to be raised in priority. If too late for this project, it may help facilitate future projects. In Work Package 7, it is stressed that once the legal status of a cable link is defined it is difficult or unwise to change that status. As the status also determines the form of remuneration (Regulated versus Merchant Cable), it important for this to happen. Within the Clean Air Package recast, the door to legislation was opened, but the step to legislation was not taken.

The above barriers are not insurmountable. PROMOTioN has supported TenneT in the preparation of an application for funding for more research into the technical and economic impact to the WindConnector Project. However, due to the fact that the timeline for the development period of UVER has been fixed along with the relevant engineering steps, it is a strongly preferred option by TenneT to decouple the DC breaker option as much as possible from the main engineering (and even project execution) process. This could be enhanced by seriously and consistently considering the introduction of a separate offshore platform for the accommodation of the HVDC CBs in the future. In this way, the current development and progress of the Ijmuiden Ver and Vattenfall platforms is not dependent on the outcome of the HVDC CB discussion.

### 3.6 CONCLUSIONS

3.6.1 **DYNAMIC FAULT ANALYSIS**

The design of the protection system for Ijmuiden offshore interconnector is described in this chapter, employing preliminary system parameters provided by TenneT. The grid model is implemented in PSCAD, and correct control and protection operation is verified in a series of tests. Based on the presently available knowledge about this upcoming offshore HVDC project, the responses of the system model are deemed realistic.

Non-selective protection strategy for VSC-HVDC grids requires blocking of all the converters on the faulted pole and opening the ACCBs on that pole. The advantages of this strategy are simplicity and low capital expenditures, but result in low reliability and security of power supply. Clearing DC faults requires complete de-energization of the faulted poles, regardless of the location and severity of the fault. In this instance, any pole-to-ground (or pole-to-pole) fault on the British side or the interconnector cable also requires disconnecting the Dutch MMCs and results in loss in capacity.

Installing the DCCB on the Ijmuiden Ver offshore platform greatly improves the resilience of Dutch MMCs to DC faults on the British side and the interconnector cable. The load flow analysis indicates that DCCB installation does not slow down the power reversal through the interconnector, and that the additional losses are very modest. An analytical method for estimating DCCB reactor losses based on the reactor inductance is provided for future reference.
The MMC fault-ride through can be achieved using two distinct protection strategies: avoiding MMC blocking or utilizing temporary blocking. Avoiding MMC blocking requires larger DCCB reactors, especially if slower mechanical DCCBs are used. However, this method minimizes the impact of DC faults on the AC system and limits the current stress on other grid components. If a fast hybrid DCCB (3ms) is used, the MMC blocking will generally be avoided because the minimal inductor size for avoiding MMC blocking is only marginally higher than the minimal inductance required by the DCCB.

When temporary blocking is used, the required DCCB reactor inductance is low because it only needs to limit the DCCB current below the DCCB’s current breaking capacity. Lower reactor size reduces the conduction losses and dynamic impact in normal operation, but somewhat increases the current stress on DC grid components during DC faults. Temporary blocking causes the AC voltage collapse while the MMC is blocked, but this state lasts for less than one grid period and is acceptable for OWF connection, according to ENTSO-E standards.

A comprehensive simulation study is undertaken to provide a table of required DCCB parameters, considering the DCCB opening time, converter blocking strategy, DCCB reactor size and the power rating of British MMCs. The results should serve as a good estimate for the DCCB design requirements. In broad terms, a fast DCCB with 3 ms opening time will require an inductor of at least 70 mH and the energy absorption capability of 15 MJ. A slow DCCB with an 8 ms opening time will require either 80 or 380 mH series inductance (temporary/permanent MMC blocking cases) and will absorb 25 or 45 MJ of energy.

Unidirectional DCCB is studied separately, and the conclusion is that it should be able to withstand considerable current stress for reverse faults. The $I^2t$ integral of the reverse fault current is estimated at $2.5e7$ A$^2$s for a hybrid DCCB. The LCS can withstand considerably higher surge currents due to its matrix structure, and should be used to conduct the reverse fault current instead of the MB.

The report also identifies the need for installing neutral bus switches at the DMR connection of each MMC pole, to prevent fault feeding through the blocked converter’s antiparallel diodes. It is demonstrated that the steady-state DMR voltage is only several kV, and current breaking capability of several hundred amps will be needed. The NBS can therefore be implemented as a low-cost passive resonant mechanical DCCB with limited voltage and current rating.

3.6.2 OVERALL CONCLUSIONS

Aside from detailed protection system study, PROMOTioN has supported WindConnector project in cost estimates for different system topologies and several aspects related to the legal status of the asset, possible market arrangement / bidding zones configuration and several other non-technical issues that are considered important for the project implementation.

Having quantified the extra costs from the utilization of DCCB for protection, it is concluded that uncertainty in the final cost of DCCB does not allow it to be considered as a viable option yet. The extra costs vary highly depending on the exact type of DCCB to be employed and extra equipment and space which will be needed to accommodate it. Furthermore, it is expected that benefits from a fully-selective protection strategy enabled by a DCCB could potentially outweigh its costs. Among such benefits, increased availability of the link, increased security of supply...
and reduced losses are named. These benefits have not been quantified within PROMOTiOn for WindConnector, thus we recommend further analysis in this area.

PROMOTiOn has performed a fundamental case-study of how various bidding zone arrangements may impact the business case for TSOs, as transmission asset owners who claim congestion rent, and for OWFs as energy producers and sellers. (This study was stipulated by the fact that the legal status of an interconnector between two OWFs is still uncertain, until regulation of hybrid assets is introduced in European network codes and legislative acts. PROMOTiOn has defined the concept of hybrid assets explicitly within Work Package 7. We recommend that this new type of assets needs to be introduced in the short-term to facilitate the development of hybrid projects such as WindConnector.) The conclusion from the bidding zone study is that the total socio-economic welfare does not change in different bidding zone configurations, but the distribution of costs and benefits between TSOs, energy producers and consumers will change. The concept of offshore bidding zones is novel, however it offers an elegant solution to the 70% availability requirement for infrastructure adjacent to interconnectors in the case of hybrid assets, at the same time allowing for a more robust business case for asset owners. If small offshore bidding zones are introduced, OWFs will receive a smaller share of the proceeds. Nevertheless, if OWFs are subsidised this may be compensated, depending on the subsidy design. The price zones should be defined in such a way that there is no network congestion within a zone. In case a wind park is connected to only one onshore market, this solution converges with the national price zone model. However, as soon as a wind park is connected to multiple markets, the advantages of this model become apparent. Without congestion within a price zone, the price of each zone can be set equal to the marginal social value of power generation in that zone. This means that there will not be counter-intuitive flows from high to low price zones and the incentives for local flexibility will be economically efficient. The definition of the zones is a function of network capacity and therefore unambiguous. More detail and exact recommendations are available in the main Deliverable 12.4.

Finally, important is the topic of procurement and interface management. Albeit not addressed in PROMOTiOn explicitly, it has been discussed with various stakeholders several times and is seen as detrimental to project implementation. The procurement issue highlights a need to clarify the roles of TSOs and the relevant DCCB suppliers and to have these explicitly reflected in the contractual arrangements. Technical interfaces and parameters, interface conditions and requirements need to be identified and documented prior to contract award.
4 BORNHOLM ISLAND – CLEANSTREAM ENERGY HUB

4.1 INTRODUCTION

In 2019 Danish developer Ørsted presented its vision of CleanStream project, an energy hub on the island of Bornholm with an idea of connecting between 3 to 5 GW of offshore wind and connecting it via DC cables to Denmark (DK) and Poland (PL), and potentially Sweden and Germany in the later phases. In May 2020 the Danish government has published its proposal for a climate action plan which aims at a significant increase in the development of offshore wind by building two energy islands connecting offshore wind farms (OWFs) and serving as hubs for cross-border electricity interconnection with other countries.

One of the proposed islands is located east from the Dogger Bank area. While the specific concept of the island is not clear at this stage, the proposal does include an artificial structure offshore, which can serve as an energy hub. The proposal includes 3GW of offshore wind and a connection between Denmark and the Netherlands. The idea of an island in the North Sea has been a focus area for the North Sea Wind Power Hub (NSWPH) consortium including Dutch TSO TenneT, Danish TSO Energinet and Dutch GSO Gasunie.

The second island is an energy hub on the existing natural island of Bornholm located in Danish waters in the Baltic Sea. As opposed to the NSWPH project, the advantage of creating a hub on Bornholm is alleviating the need to build large artificial infrastructure, as Bornholm could provide space and ability to host all HVDC equipment in the secure onshore environment.

The PROMOTioN report D12.4 contains a detailed review of advantages of grid topologies based on energy hubs. In this Chapter of Short-Term Project supplement, we present an overview of the feasibility studies that PROMOTioN has performed for Bornholm island energy hub. This analysis has been performed jointly by project partners based on the publicly available information and multiple assumptions, which means that obtained results are not definitive but rather indicative. The analysis that PROMOTioN has performed is intended to give a first outlook on the feasibility of the Bornholm energy island and potential technical and market solutions that could facilitate its implementation. It is believed that building the first energy hub on Bornholm (essentially onshore) in the short-term will significantly de-risk future similar projects and lay down the first steps to adopting technical and legal solutions that will be necessary for the deployment of meshed offshore grid.

4.2 BORNHOLM ISLAND AS AN ENERGY HUB

The idea of the energy hub project is to have windfarms installed in the area around Bornholm and evacuate wind energy directly to Greater Copenhagen area on Zealand, by building a HVDC connection from Bornholm to Zealand. At the same time, Bornholm’s proximity to Poland (PL) enables the construction of a connection from the island to PL, and in this way establish an interconnection between Denmark and Poland. Currently, the island of Bornholm is connected to Sweden via 60 kV AC 60 MW cable to ensure stable electricity supply for the local population. While not included in the simulations in PROMOTioN, a part of the Bornholm project could include a
power outlet to the island of Bornholm. However, as the electricity consumption on the island is limited, this will not change the overall setup of the project nor the results at hand. A schematic diagram showing location of the island, potential OWFs and connections from Bornholm to the Danish and Polish shores is given in Figure 4-1.

A recent screening by the Danish government has identified potential locations where future OWFs can be constructed. It is assumed that up to 3 GW of wind capacity could be installed already by 2030 in the Danish EEZ south-west from Bornholm. At the same time, a direct connection from Poland to Denmark has been presented in TYNDP 2018. These preliminary ideas are now taken further to explore an opportunity of using hybrid connection, both to trade energy between two countries and evacuate offshore wind generation. The assumption is that such project can bring substantial cost savings as opposed to a separate point-to-point interconnector and windfarms being connected to DK.

PROMOTioN has supported project promoters by conducting studies on:

- The optimal grid topology,
  - Optimal HVDC converter rating and cable rating
  - Hub busbar design
  - Protection strategies
- Market simulation
  - Socio-economic welfare distribution
  - Offshore bidding zone implications
- Change process for the maximum allowed Loss of Infeed
- Recommendations on support scheme design to foster construction of OWFs
- Ownership options for the hybrid infrastructure
- Financing options by EU
4.3 DISCUSSION

This section contains a qualitative discussion around some of the potential benefits that Bornholm Energy Hub could bring, some of the rationale behind building the hub on existing island, ways of implementing and further prospects. Topics that are discussed were not extensively explored within the PROMOTioN group conducting feasibility studies for Bornholm Energy hub. At the same time, we believe it is important to reflect upon the below discussed topics.

4.3.1 MULTITERMINAL DC VIS-A-VIS AC HUB

Power system infrastructure on Bornholm island must adhere to a range of usual criteria related to being safe, reliable, affordable, environmentally friendly and expandable. One of the key decisions to be taken with regard to the actual implementation of Bornholm energy hub is whether to develop the hub as an AC- or DC-multi-terminal hub, or a combination thereof. An example of how AC and DC hub could be implemented for the scenario where 3 GW of offshore wind is connected to the island and 2.1 GW links are built towards Denmark and Poland is given in Figure 4-2. It can be seen that AC hub requires one extra converter with the same capacity of connected OWFs and same capacity of transmission corridor.

AC technology is well-known and proven both in technical and commercial terms. It could be utilised as a number of point-to-point HVDC links from the island to shore, interfaced with each other on the island on the AC side. It is generally well understood among project developers how to integrate AC connections in the power system, how to utilise equipment from different OEMs, and what are the procurement models. System operation guidelines, grid codes and technical standardisation are well developed for AC connections. However, the connection of several converters from different manufacturers onto one AC hub is still not straightforward as it would face challenges from a dynamic stability perspective and from a multi-vendor system integration perspective. Significant analysis would have to be undertaken to guarantee the system frequency stability, and to ensure that any unwanted control interactions between the converters on the AC side are avoided. These challenges have not been analysed in detail within PROMOTioN and remain as a recommendation for the future work.
On the downside we note that implementing Bornholm project as AC hub would imply a separate AC/DC converter on the island for each of the HVDC links to the mainland. This not only leads to higher CAPEX and footprint requirements, but also to higher losses as interconnection flows pass through two converters in the hub, incurring about one percent loss in each, and to lower availability due to the additional outage time associated with the additional converters.

In this perspective, the DC hub may be a cheaper option. In case of the DC hub, offshore wind farms will require dedicated HVDC converters (although the required capacity only depends on the capacity of OWF and will not grow with the increase of transmission capacity from DK to PL) to transform their output into DC when feeding energy into the hub. Although in technology readiness level (TRL) of some HVDC components is lower than for HVAC, the technology to build such a multi-terminal system exists and has been demonstrated in several projects worldwide (see section 4.3.5 for examples). The main disadvantage is the lack of system operation guidelines, grid codes and technical standards, which means that multi-terminal systems to date have pre-dominantly been single vendor, which is not desirable from a competitive tendering, expandability and vendor lock-in perspective.

Therefore, concluding what is actually cheaper should be based on a full lifetime CBA taking into account the particular project configuration, topology, and the interconnection and offshore wind power flow scenarios. Figure 4-2 shows that with the assumed capacities of offshore wind and interconnection, AC hub does result in 4 converters against 3 for DC; at the same time AC hub offers additional transfer capacity for the interconnection flows. Extrapolating from this, it is anticipated that hubs hosting a higher ratio of interconnection capacity vs offshore wind export capacity will benefit more strongly from DC.

The following drawbacks of AC hubs as compared to DC are identified:

- Higher capital expenditures – each HVDC link from island to DK or PL would require a separate dedicated HVDC converter as an interface from this link to AC busbar on the hub.
- Lower availability of the north-south, i.e. from Denmark to Poland, transmission corridor – the more components (converters) are on the way from DK to PL, the higher is the unavailability of this electrical path, as compared to the DC hub option.
- Increased losses in converters for north-south flows – electricity flowing from Denmark to Poland (or vice versa) would have to be converted from DC to AC and then again to DC when passing through the hub.
- Larger space requirements – this is related to the fact that HVDC converters usually have large footprint, which may not be as problematic on the natural island as offshore but still needs to be considered when AC hub requires more converters than DC.
- Technical challenges in multi-vendor AC hub integration – New solutions for maintaining frequency stability and avoiding multi-vendor converter control interactions need to be applied.

In contrast, DC hub implementation entails issues related to:

- Multi-vendor converter interoperability – AC/DC converters from different OEMs have different control schemes due to the fact that there are no HVDC codes that would impose certain control capabilities, hence each OEM delivers its own unique solution.
- Application of unknown technology – Multi-terminal HVDC grids will require protection which as yet has not been applied in any European projects.
Absence of system operation guidelines, grid codes and technical standardisation (in contrast to the first point, this relates to the absence of guidelines which aim at solving interoperability issues).

Procurement – it is yet unclear whether OEM manufacturers would be willing to deliver HVDC equipment on the regular warranty terms knowing that it would be interfaced with other manufacturers’ equipment on the DC side. Multi-vendor DC hubs have not been implemented before.

4.3.2 FUTURE EXTENSION

In the present report we have considered a period up to 2030 and assumed that within this period 3 GW of offshore wind can be expected to be built around the island and interconnectors from Denmark to Poland can be laid. The island, however, offers opportunities for the further expansion, both in terms of connected wind capacity and installed connections to other countries. In particular Bornholm’s geographic location allows to build HVDC corridors to Sweden and Germany in the second phase of its development (possibly beyond 2030), in this way creating a multiterminal infrastructure for energy trading between 4 EU states (see Figure 4-3).

Figure 4-3 Second phase of hub development

PROMOTioN has not investigated directly how exactly these additional connections would impact the socio-economic welfare distribution across the connected countries or what could be the implications on the business case of OWF developers. In general, projects that increase interconnection levels between EU countries benefit the EU society allowing for a more efficient generator dispatch on the EU level, increased security of supply and flexibility in grid operation. Therefore, we note that Bornholm island offers unprecedented opportunity to minimize the amount of infrastructure that would be required otherwise to connect 4 different EU states. Its geographic position between Nordic and Central European regions makes it a perfect candidate for the development of a first multi-terminal European energy hub.
4.3.3 STEP-WISE DEVELOPMENT

In order to manage the risk associated with the application of novel technology such as a DC hub, a step-wise approach can be envisaged, which on the one hand allows for the realisation of the politically mandated 2 GW renewable energy targets using ‘known’ low-risk technology, whilst ensuring the realisation of all technical requirements to enable the creation of a DC hub. An example of such a stepwise development is given below:

1. As a first step, an interconnector between DK2 and PL would be to build with an HVDC switchyard on Bornholm island.

   The HVDC switchyard should be built such that there is sufficient space and functionality for future expansion with HVDC switchgear (incl. HVDC circuit breakers) even though these are not required at the current phase. The HVDC switchyard could be implemented as a gas insulated substation in order to reduce the required footprint and building height.

   The link between Bornholm and DK2 should be rated at twice the loss of infeed in DK2 (e.g. 2 x 600 MW), and be implemented as bipolar with dedicated metallic return (DMR) or as two monopoles. The switchyard on Bornholm should be a single bipolar busbar or a double monopole busbar, respectively.

   The link between Bornholm and PL should be rated at the difference of the wind power to be connected to Bornholm and the capacity of the link to DK2, e.g. 800 MW in this example. The link can be implemented as bipolar or monopole, and connected to the HVDC switchyard and it should be the same architecture as the link to Denmark.

   The whole link from DK2 to PL including the Bornholm HVDC switchyard should be procured from one single vendor to ensure low risk delivery.

   The HVDC system behaviour at the Bornholm switchyard should be fully characterised by means of a draft HVDC grid code and system operation guideline, to effectively create a DC point of connection (PoC).

   Building this step will require in some temporary over capacity on the DK2 - Bornholm link which may require some anticipatory investment. During this period, the link should not be operated beyond the maximum loss of infeed capacity in DK2 e.g. 600 MW.

2. As a 2nd step, 2 GW of offshore wind farms can be realised around Bornholm and brought to the island using AC cables. The AC cables can be connected to an AC hub first which is then connected to the DC hub via converters. Due to the AC hub, the converter size can be decoupled from the size of individual wind farm, only ensuring that the total capacity of connected offshore wind farms does not exceed converter capacity, but with no need to exactly match the capacity of each new wind farm by installing a new converter.

   The converters should be tendered competitively using the specifications for the DC PoC, providing an excellent learning opportunity for specifying and handling multi-vendor converter grid integration.

---

2 In a given example, in case 800 MW is chosen as a capacity between PoC and Poland, this connection has to be implemented as bipolar to avoid losing 800 MW at once, which would exceed maximum loss of infeed in Denmark DK2.
Alternatively, to stick to low risk implementation, they could be procured from the same vendor as the first step, but still adherence to the connection requirements should be shown.

This step can be realized without HVDC circuit breakers as the maximum loss of infeed can be limited through grid splitting using the bipole or double busbar arrangement\(^3\). Power can be transferred between the bars through the AC hub which provides a redundant path if necessary.

In case the converters on Bornholm island are rated equal to the link ratings, the HVDC hub could be disconnected (e.g. in case of unexpected difficulties) by means of disconnecting switches in which case the whole system would simply be connected by the AC hub.

3 As a 3\(^{rd}\) step, the offshore wind capacity can be expanded. This will require additional export capacity to DK2 and maybe PL. In this case the maximum loss of infeed cannot be satisfied anymore, and HVDC protection needs to be included. Based on the multi-vendor grid integration experience from the 2\(^{nd}\) step, this should be tendered competitively.

4 Finally, the DC point of connection can be expanded with further DC links to Sweden and Germany. These links can be tendered competitively and integrated into the existing system. This is where the DC hub really starts demonstrating its benefit vs. the AC hub as investments in converters and associated losses, maintenance, downtime and footprint are avoided.

4.3.4 KEY PROJECT TO DE-RISK FUTURE MESSED HVDC GRIDS

Depending on the actual project ratings, timings, desire for innovation, and parties involved, various different versions of such stepwise expansion plans can be drafted introducing various degrees of technological novelty and complexity at each step. The key point is that the Bornholm island’s role in Denmark’s push for offshore windfarm development constitutes a unique opportunity to de-risk, pilot and showcase multi-vendor, multi-purpose and multi-terminal HVDC grid technology. The pilot project would not only demonstrate multi-vendor and multi-terminal technology, but it would realize the socio-economic benefits of applying such technology. Doing so can change the HVDC grid development paradigm and thereby not only unlock socio-economic welfare benefits of the future North Sea offshore wind development but also regain Europe’s traditionally leading role in HVDC technology development and manufacturing.

The Bornholm island lends itself to the demonstration of the following technical aspects:
- Development and application of HVDC system operation guidelines and grid codes
- Specification and realization of an HVDC point of connection
- Realisation of a multi-vendor HVDC system
- Application of HVDC system protection e.g. HVDC circuit breakers

\(^3\) Assuming that there is a negligible probability of pole-to-pole fault on bipole connections in case cables are not bundled
- Realisation of multi-purpose (hybrid) transmission infrastructure
- (Realisation of an HVDC gas insulated substation)

All of these aspects can be applied in a step-wise approach on an existing island thereby managing reducing the risk involved with piloting new technology. In order to offset the additional effort required to realize this pilot project, PROMOTioN recommends full support from the EU for any of the anticipatory investments required to do so, as long as these are accompanied with a commitment to actually realize a DC hub.

It is strongly recommended to consider Bornholm island in the upcoming proposals for a multi-terminal multi-vendor HVDC pilot project as part of the Horizon Europe funding opportunity.

4.3.5 TECHNOLOGY READINESS LEVEL

Several projects currently in development demonstrate that multi-terminal HVDC grid technology in principle is ready for application (Caithness-Moray scheme, Ultranet), provided that they are delivered by one single vendor. Multi-terminal HDVC projects in China have shown that there are no technology showstoppers towards building multi-vendor multi-terminal HVC grids. Similarly, projects in Europe such as BestPaths research project and the Johan Sverdrup power-from-shore project have shown that vendor interoperability between control systems is in principle possible, even though the specification, qualification and procurement models have to be changed from the traditional single vendor model. Similar multi-vendor converter integration issues are likely to be encountered in the realisation of an AC hub too, so would have to be solved either way.

The PROMOTioN project has shown that HVDC circuit breaker technology and gas insulated substation technology is in principle sufficiently mature for application in the real world. Similarly, HVDC grid protection has been shown to be sufficiently developed and also applicable in multi-vendor settings. The integration of these components into one functioning system is seen as a major hurdle, particularly in the absence of a HVDC grid code. It is PROMOTioN’s opinion that the CENELEC Technical specification 50654 ‘HVDC Grid Systems and connected Converter Stations - Guideline and Parameter Lists for Functional Specifications’ combined with the CIGRE technical brochure 657 – ‘Guidelines for the preparation of Grid Codes for multi-terminal schemes and DC Grids’ in addition to the deliverables from the BestPaths and PROMOTioN project should provide a sufficient starting ground to base an approach for the system integration aspect on.

The market size of HVDC circuit breakers and HVDC gas insulated switchgear is still somewhat limited which complicates competitive tendering, and it is thus recommended to also consider non-European manufacturers, several of which have developed viable solutions, to ensure a sufficiently large offering and reduce prices.

The multi-purpose use of transmission infrastructure has often been seen as a regulatory hurdle, however, with the first power flowing over the Kriegers Flak link, it has been shown that this problem can be solved. To provide further reassurance, the North Sea Energy Cooperation has made enabling such combined use infrastructure projects a spearhead in their recommendations for the European Commission as it is recognized that they can bring significant benefit.
Based on the above it can be said that all the main building blocks for the realisation of a HVDC hub pilot project on Bornholm are in place, and that sufficient guidance exists for the successful integration of these building blocks.

### 4.3.6 FOOTPRINT OF DC AND AC HUB

As it was previously mentioned, implementation of the hub on Bornholm island is especially attractive considering the potential footprint of the hub. As a representative values PROMOTioN suggests using:

- ~10,000 m² for the footprint of a single 1GW HVDC converter
- ~250 m² (per pole) for the footprint of a single DCCB

With the intention to build several converters and potentially DCCBs when expanding the hub, implementation in the offshore environment would lead to an excessively high extra CAPEX for the installation of offshore platforms that would be required to host this large equipment. Bornholm is a natural island with abundant space available for the construction of energy hub. As most of the windfarms will be located on the western side of the island, in the industrial area of Roenne, there should not be any negative impacts on the local communities due to the visual amenity impacts. Therefore, PROMOTioN emphasizes that implementing the first European multi-terminal HVDC energy hub on the island of Bornholm is especially advantageous when considering large space requirements for hosting the HVDC infrastructure.

### 4.3.7 VARIATION IN OFFSHORE WINDFARM SIZE

Across this report it is assumed that 3 GW of wind power could be installed around Bornholm island by 2030. The tendering of wind development sites around Bornholm island is assumed to be done in two phases:

1. Installation of 2 GW by 2026
2. Installation of 1 GW additional wind power by 2028

In order not to miss other potentially cost-effective solutions, variations are proposed:

- Installation of 1850 MW and 2150 MW of wind power at the island by 2026
- Installation of 850 MW and 1150 MW by 2028 is acceptable

More detailed assumptions and approach are introduced during the optimization process (to find the cost effective solution(s)). This approach is detailed in section 4.4.5.1.

Eventually, wind capacity might be tendered in a different way, with the larger deviations than the abovementioned, resulting in a different amount of wind connected to the hub in the initial years of its operation. The exact economic impact has not been studied within PROMOTioN. It would require an extensive scenario analysis, including the analysis of how interconnector (exchange) flows would be affected by a change in wind energy injection levels.

### 4.4 TECHNICAL AND ECONOMIC ANALYSIS

#### 4.4.1 GRID CONCEPT DEVELOPMENT

The workflow for the technical and economic analysis is shown in Figure 4-4. The procedure is applied for both DC hub and AC hub.
4.4.2 AC GRID CONSTRAINTS

4.4.2.1 MAXIMUM LOSS OF INFEED

The following are the values considered for the maximum loss of infeed in the surrounding market areas:

Central European Area: 3 GW
- Denmark (DK1): 700 MW
- Germany: 3 GW
- Poland: 3 GW

Nordic Area: 1.2 GW
- Denmark (DK2): 600 MW (based on agreements with neighbouring countries, frequency reserve procurement). A value of 750 MW and 900 MW is also considered for CAPEX calculation, with the purpose of studying the impact of this parameter.
- Sweden: 1.2 GW

4.4.2.2 TEMPORARY LOSS OF INFEED

Considering the DC hub configuration, and depending on the implemented DC protection strategy, a temporary loss of power higher that the maximum acceptable loss of infeed for a short period of time (e.g. 100 to 200 ms) can occur on the entire DC grid. It is therefore necessary to verify that the interconnected AC system would not incur power system instabilities. Similarly, the wind turbine generators will be subjected to this temporary loss of power and need to be able to rapidly restore the power once the fault is eliminated. The ability of the AC system and wind farm generator to sustain this temporary loss of infeed depends on several aspects such as AC system inertia, power flow before fault and type of the employed wind turbine generator and its control. In this document it is assumed that for DC protection based on non-selective fault clearing strategy the AC system is able to sustain such temporary loss.
4.4.3 TECHNOLOGY ASSUMPTIONS

4.4.3.1 HVDC CABLES AND CONVERTER RATINGS

A maximum current rating of 2 kA is considered for the HVDC XLPE cables. Thus, depending on the voltage rating, the following power per cable is assumed:

- 320 kV: 640 MW
- 400 kV: 800 MW
- 450 kV: 900 MW
- 525 kV: 1 GW

Indicative maximum ratings considered for state-of-the-art HVDC converter:

For symmetrical monopole configuration:

- 320 kV: 1.4 GW
- 400 kV: 1.8 GW
- 525 kV: 2.3 GW

For bipole configuration:

- 320 kV: 1.8 GW
- 525 kV: 3 GW
- 640 kV: 3.6 GW

4.4.3.2 CONVERTERS CONFIGURATION

When considering the DC hub configuration, it is necessary to take into account the compatibility among different converter configurations. The following are the main assumptions:

- Bipole and rigid bipole can be mixed together.
- Metallic return is not mandatory when the total capacity of a bipole is lower than the allowed loss of infeed.
- In case of several parallel bipoles the metallic return can be mutualized if the maximum loss of infeed condition in case of N-1 contingency is fulfilled, see Figure 4-5. This configuration is hereunder called “rigid bipole with mutualized metallic return”.
- Bipole is not mixed with asymmetric monopole (ASMP). The asymmetric monopole can transfer the power only through one polarity, which could entail a mismatch of power flow when mixing bipoles and asymmetric monopoles.
- Symmetric monopole (SMP) configuration cannot be mixed with other configurations.

---

4 Converter configuration options are described in PROMOTioN Deliverable 1.1: “Detailed description of the requirements that can be expected per work package” in chapter 2.3.1.3.  
https://www.promotion-offshore.net/fileadmin/PDFs/160415_PROMOTioN_WP1_D_1.1_V1.0.pdf
4.4.4 TRANSMISSION NEED SCENARIOS

Table 43 shows the scenarios that have been originally chosen for the installed capacity of wind farms and for the total transmission capacity from Bornholm to DK and from Bornholm to PL. The total installed wind farm capacity is assumed to be of 2GW for 2026 and of 3GW for 2028. In order to reduce the number of cases and to apply the methodology, the studied scenarios are:
- 1a, 2a, 2b with 600 MW maximum allowed loss of infeed
- 2a, with maximum allowed loss of infeed of 750 MW and 900 MW

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Total offshore wind generation Bornholm [GW]</th>
<th>Total transmission capacity Bornholm - DK [GW]</th>
<th>Total transmission capacity Bornholm - Poland [GW]</th>
</tr>
</thead>
<tbody>
<tr>
<td>2026</td>
<td>2026</td>
<td>2026</td>
<td>2026</td>
</tr>
<tr>
<td>1) not all energy can be sent to DK</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1a</td>
<td>1,5</td>
<td>1,5</td>
<td>1,5</td>
</tr>
<tr>
<td>1b</td>
<td>2,1</td>
<td>2,1</td>
<td>2,1</td>
</tr>
<tr>
<td>1c</td>
<td>1,4</td>
<td>2,4</td>
<td>0,6</td>
</tr>
<tr>
<td>2) all energy can be sent to DK</td>
<td>2,6</td>
<td>3,6</td>
<td>0,6</td>
</tr>
<tr>
<td>2a</td>
<td>2</td>
<td>3</td>
<td>0,6</td>
</tr>
<tr>
<td>2b</td>
<td>2,6</td>
<td>3,6</td>
<td>0,6</td>
</tr>
<tr>
<td>2c</td>
<td>2</td>
<td>3</td>
<td>0,6</td>
</tr>
</tbody>
</table>

Example: Only one metallic return is needed for DK2 <-> BH to respect N-1 criteria

Metallic return can be mutualized between bipoles:

Metallic return is not mandatory when total capacity of bipoles is lower that the allowed LoL

Figure 4-5: Assumption for Rigid Bipole and mutualisation of metallic return between several bipoles
4.4.5 CHOICE OF THE OPTIMIZED DC HUB CONFIGURATION

4.4.5.1 METHODOLOGY

Starting from the scenarios depicted in Table 43 a large number of sub-scenarios has been defined considering all the different variables shown in Table 44. The number and ratings of converters and cables have been calculated for each of the sub-scenario taking into account the maximum allowed loss of infeed and the maximum current allowed in a cable (2 kA).

Maximum (permanent) loss of infeed has been considered not to be violated during the following contingencies:
- Shutdown (or fault) of one pole of a converter in bipolar configuration. Shutdown of both poles of converters is not considered.
- Shutdown (or fault) of a converter in symmetric monopolar configuration
- Cable fault on a pole of a bipole. Pole-to-pole fault is not considered.
- Cable fault on a pole of a symmetric monopole

It is assumed that the windfarm capacity can vary as follows:
- Installed in 2026: from 1850 MW to 2150 MW (50 MW increments)
- Extra capacity installed in 2028: from 850 MW to 1150 MW (50 MW increments)

The costs of converters, DC cables and protection equipment (DC circuit breakers and reactors), including CAPEX, have been calculated for each sub scenario. The costs per MW have been calculated using the following formula:

\[
\text{Cost per MW} = \frac{\text{Total project Costs}}{\text{Power(DK2 ↔ BH) + Power(BH ↔ Poland) + Wind farm generation}}
\]

It should be noted that the same formula could be used to assess and optimize the different scenarios from CAPEX and OPEX (Losses and EENT) point of view. This study is not detailed in the current deliverable. In other words, the selected scenarios are based only on the CAPEX indicator. However, some results considering losses are given in 7.3.2.3. A sensitivity analysis has been carried out considering different energy price and cost for the MR cable using 33% or 66% of the cost of HV cable cost. Cost, model and data assumptions are presented in appendix 7.3.2.1.
Table 44 Variables of the sub-scenarios

<table>
<thead>
<tr>
<th>Variables:</th>
<th>Possibilities</th>
<th>Number of states taken by a variable</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scenario</td>
<td>1a, 1b, 1c, 2a, 2b, 2c</td>
<td>6</td>
<td></td>
</tr>
<tr>
<td>DC hub configurations</td>
<td>(Rigid bipole and bipole with mutualized MR) OR (Only SMP)</td>
<td>3</td>
<td>ASMP and bipoles are not mixed in the same DC grid</td>
</tr>
<tr>
<td>Maximum allowed loss of infeed</td>
<td>600 MW, 750 MW, 900 MW</td>
<td>3</td>
<td></td>
</tr>
<tr>
<td>Cable voltage</td>
<td>320, 400, 450, 525 kV</td>
<td>4</td>
<td>With DC hub, the whole network has the same voltage.</td>
</tr>
<tr>
<td>Wind farm Capacity</td>
<td>2026 : 1850 =&gt; 2150 MW (50 MW increments)</td>
<td>49</td>
<td></td>
</tr>
<tr>
<td></td>
<td>2028 : 850 =&gt; 1150 MW (50 MW increments)</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Total : Capacity of 2700 to 3300 MW</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Energy price</td>
<td>50 €/MWh and 100 €/MWh</td>
<td>2</td>
<td>Used to monetize losses</td>
</tr>
<tr>
<td>Metallic return CAPEX</td>
<td>0.33 and 0.66 x HV cable CAPEX</td>
<td>2</td>
<td></td>
</tr>
<tr>
<td>Total number of sub-scenarios for DC hub:</td>
<td></td>
<td>42336</td>
<td>Additional combinations between DK2-Bornholm and Poland are considered. E.g. Bipolar in DK2 and (Rigid bipolar) in Poland and Bornholm</td>
</tr>
</tbody>
</table>

An optimization tool has been developed in Python environment in order to:
- Make a first selection of the sub-scenarios that fulfill the requirement in terms of rating and maximum loss of infeed. The optimal solution for a given input parameters (voltage, configuration, loss of infeed, installed power in 2026 and 2028) is then returned.
- Calculate the cost (M€/MW) of each sub scenario.

Figure 4-6 shows an example of cost calculated for different solutions. For better readability Figure 4-7 shows the cost value in additional per cent comparing to the best solution. In this example, the best solution is a SMP rated 320 kV with wind farm installed capacity of 2150 MW in 2020 and 1150 MW in 2028. The chosen solution, a SMP rated 320 kV with wind farm installed capacity of 2000 MW in 2020 and 1000 MW in 2028, is 3.75% more expensive.
In Figure 4-8 each bubble represents the best solution for a given wind farm capacity in 2026 and 2028. The values are the additional % of CAPEX comparing to the best solution for this specific scenario and loss of infed

<table>
<thead>
<tr>
<th>Installed power in 2026 (MW)</th>
<th>Installed power in 2028 (MW)</th>
<th>SMP</th>
<th>Bipole</th>
<th>Rigid</th>
<th>Bipole + Mutual MR</th>
<th>SMP</th>
<th>Bipole</th>
<th>Rigid</th>
<th>Bipole + Mutual MR</th>
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<th>Bipole</th>
<th>Rigid</th>
<th>Bipole + Mutual MR</th>
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<td>1400</td>
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<td>0.144034</td>
<td>0.246623</td>
<td>0.219430</td>
<td>0.222827</td>
<td></td>
</tr>
</tbody>
</table>

---

Figure 4-6 Cost of different solutions, scenario 1a, allowed loss of infed 600 MW
<table>
<thead>
<tr>
<th>Installed power in 2025 (MW)</th>
<th>Installed power in 2020 (MW)</th>
<th>330 kV (€/MWh)</th>
<th>500 kV (€/MWh)</th>
<th>400 kV (€/MWh)</th>
<th>400 kV (€/MWh)</th>
<th>500 kV (€/MWh)</th>
<th>500 kV (€/MWh)</th>
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<tr>
<td>500</td>
<td>5.94</td>
<td>11.3</td>
<td>14.4</td>
<td>15.9</td>
<td>17.3</td>
<td>18.8</td>
<td>18.8</td>
</tr>
<tr>
<td>1000</td>
<td>10.53</td>
<td>16.8</td>
<td>19.8</td>
<td>21.9</td>
<td>22.7</td>
<td>23.4</td>
<td>23.4</td>
</tr>
<tr>
<td>1500</td>
<td>15.85</td>
<td>21.0</td>
<td>23.9</td>
<td>25.4</td>
<td>26.0</td>
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<td>2000</td>
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<td>28.1</td>
<td>29.2</td>
<td>29.7</td>
<td>30.1</td>
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<td>2500</td>
<td>26.34</td>
<td>30.9</td>
<td>32.8</td>
<td>33.5</td>
<td>33.8</td>
<td>34.0</td>
<td>34.0</td>
</tr>
<tr>
<td>3000</td>
<td>31.60</td>
<td>35.9</td>
<td>37.3</td>
<td>37.6</td>
<td>37.8</td>
<td>38.0</td>
<td>38.0</td>
</tr>
</tbody>
</table>

Figure 4-7 cost in per cent, only solution < 1.1 the best cost, , scenario 1a, allowed loss of infeed 600 MW

Figure 4-8 cost in per cent as function of wind farm installed power in 2026 and 2028, , scenario 1a, 600 MW LoI

Configurations with 3000 MW total windfarm capacity

Cheapest solution (CAPEX/ MW)
4.4.5.2 RESULTS

The cost calculation has been performed taking into account the following set of data:
- Result considering only cable and converter CAPEX (results are shown in this section)
- Results considering cable and converter CAPEX and cable losses (results are shown in appendix 7.3.2.3)
- Sensitivity analysis considering energy price variation (results are shown in appendix 7.3.2.4)
- Sensitivity analysis considering different MR cable cost (results are shown in appendix 7.3.2.5)

For the first set of data (only cable and converter CAPEX) the chosen solution for each selected scenario are shown in Figure 4-9 and Table 45. Cost of MR cable (MV cable) is assumed to be 0.33 the cost of a HV cable.

All solutions are rated 320 kV. Indeed, as far as the losses and expected energy not transmitted are not taken into account in the optimization phase, the more interesting solutions from CAPEX point of view are the solutions with low voltage rating.

The optimized configuration for the scenario 1a with 600 MW allowed loss of infeed is a SMP. In fact, for this scenario, 6 cables are needed whatever the solution is, with less power rating for monopolar SMP configuration.

The optimized configurations for scenarios 2a and 2b are bipole configurations with mutualized MR for the link between the DC hub and DK and rigid bipole for the connection of the wind farm and the link between the DC hub and PL.

It is worth to note that for the scenario 2a and 1b there seems to be no advantage to increase the maximum LoI. This is due to the fact that the number of cables and converters needed are still the same up to 900 MW loss of infeed. In other words, three corridors are needed up to 900 MW LoI. If the LoI is higher than 1000 MW, advantage could exist. It can be concluded that the benefit of increasing the maximum allowed loss of infeed depends on the specific converter and cable ratings. This benefit is only captured in discrete steps when it becomes possible to save on the number of assets.

![Figure 4-9: Chosen configurations for the selected scenarios](image)
Table 45 Cost of each chosen solution

<table>
<thead>
<tr>
<th>Scenario</th>
<th>CAPEX [k€/MW]</th>
<th>Total CAPEX [M€]</th>
<th>Configuration</th>
</tr>
</thead>
<tbody>
<tr>
<td>1a (600 MW LoI)</td>
<td>284</td>
<td>1706</td>
<td>SMP</td>
</tr>
<tr>
<td>2a (600 MW LoI)</td>
<td>290</td>
<td>1913</td>
<td>Bipole+Mutual MR + Rigid Bipole</td>
</tr>
<tr>
<td>2b (600 MW LoI)</td>
<td>313</td>
<td>2253</td>
<td>Bipole+Mutual MR+ Rigid Bipole</td>
</tr>
<tr>
<td>2a (750 MW LoI)</td>
<td>290</td>
<td>1913</td>
<td>Bipole+Mutual MR + Rigid Bipole</td>
</tr>
<tr>
<td>2a (900 MW LoI)</td>
<td>290</td>
<td>1913</td>
<td>Bipole+Mutual MR + Rigid Bipole</td>
</tr>
</tbody>
</table>

Table 46 shows the results for all scenarios and all maximal loss of infeed. For most of the scenarios, bipolar with mutualized metallic return is observed as the best architecture. Rated voltage of 320 kV is selected for most of the best solutions. A 400 kV solution is observed as the best in one scenario (scenario 1a with 750 MW maximum allowed loss of infeed). This is due to the fact that by increasing the voltage, the cable capacity in terms of power transmission is higher, therefore a single bipolar with 2x750 MW can be chosen, reducing the number of cables and converters.

Table 46 Summary results for all maximum allowed loss of infeed and all scenarios

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>600</td>
<td>1a</td>
<td>284</td>
<td>1706</td>
<td>SMP</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>2a</td>
<td>239</td>
<td>1716</td>
<td>Bipole+Mutual MR+ Rigid Bipole</td>
<td>4%</td>
</tr>
<tr>
<td></td>
<td>2b</td>
<td>313</td>
<td>2253</td>
<td>Bipole+Mutual MR+ Rigid Bipole</td>
<td>37%</td>
</tr>
<tr>
<td>750</td>
<td>1a</td>
<td>229</td>
<td>1574</td>
<td>Bipole+Mutual return: 400 kV</td>
<td>0%</td>
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<tr>
<td></td>
<td>2a</td>
<td>238</td>
<td>1716</td>
<td>Bipole+Mutual MR+ Rigid Bipole</td>
<td>4%</td>
</tr>
<tr>
<td></td>
<td>2b</td>
<td>279</td>
<td>1977</td>
<td>Bipole+Mutual MR+ Rigid Bipole</td>
<td>22%</td>
</tr>
<tr>
<td>900</td>
<td>1a</td>
<td>229</td>
<td>1574</td>
<td>Bipole+Mutual return: 400 kV</td>
<td>0%</td>
</tr>
<tr>
<td></td>
<td>2a</td>
<td>238</td>
<td>1716</td>
<td>Bipole+Mutual MR+ Rigid Bipole</td>
<td>4%</td>
</tr>
<tr>
<td></td>
<td>2b</td>
<td>279</td>
<td>1977</td>
<td>Bipole+Mutual MR+ Rigid Bipole</td>
<td>22%</td>
</tr>
</tbody>
</table>

4.4.5.3 CONCLUSIONS

Results considering only CAPEX with (price(MR) = 0.33 * price(HV)) :

- For most of the scenarios, rigid bipolar rated 320 kV with mutualized metallic return are observed as the best architecture. This is essentially a consequence of the quite low value of the maximum allowed LoI that excludes the symmetric monopolar solution or higher values of voltage.
- A 400 kV solution is observed as the best solution overall, but requires LoI at 750 or 900 MW.

Results considering CAPEX and losses (price(MR) = 0.33 * price(HV)) :

- Same trends as if only CAPEX is considered are observed.
Sensitivity to parameters:
- The trends are still the same by increasing the energy price (50 to 100 €/MWh)
- The trends are still the same by increasing the cost of the metallic return cable (price(MV) = 0.66 * price(HV)). This is mainly due to the fact that only one mutualized MR is used for each proposed “best” architecture

**4.4.6 IMPLEMENTATION OF PROTECTION STRATEGIES FOR DC HUB**

As discussed in the section 4.3.1, DC technology could be an attractive alternative for the hub implementation. At the same time there are significant technical complexities related to the protection system that would ensure that the security of supply in the wider system is not jeopardized by the DC hub. This section elaborates on the implementation of different DC protection schemes.

Due to the heavy calculation needed to compute economic key performance indicators (Capital expenditure, Expected Energy Not Transmitted and losses) and technical key performance indicators (active and reactive power time restorations), it was decided to restrict the studies to only four scenarios:
- Scenario 1a with 750 MW LoI and 400 kV voltage rating
- Scenario 1b with 600 MW LoI and 320 kV voltage rating
- Scenario 2a with 600 MW LoI and 320 kV voltage rating
- Scenario 2b with 750 MW LoI and 320 kV voltage rating

The choice of these four scenarios is made according to following statements:
- Keep at least the 3 cheapest topologies (based on the CAPEX per installed power at each node)
- There should be one scenario where all energy can be sent to Denmark (DK)
- Cover the most possible scenarios and allowed loss of infeed

The single line diagram of scenarios 1a, 1b, 2a and 2b for DC hub configuration are depicted in Figure 4-10, Figure 4-11, Figure 4-12 and Figure 4-13 respectively.

![Single line diagram of scenarios 1a, 1b, 2a and 2b for DC hub configuration](image-url)
To protect the DC hub against fault, four protection strategies have been employed based on the work carried out within PROMOTioN WP4.

- Full Selective (FS) Fault Clearing Strategies (FCS) using Mechanical DC Circuit Breaker (M-DCCB), also called slow DCCB (S-DCCB).
- FS FCS using Hybrid DC Circuit Breaker (H-DCCB), also called fast DCCB (F-DCCB).
- Non-Selective (NS) FCS using M-DCCB.
- NS FCS using Full-Bridge MMC converters.

Some assumptions have been made in order to properly design the protection system layout:

- DC breakers are used only at DC hub. A cable fault on a link between BH and DK or BH and PL will be cleared by the DCCB at the DC hub and by the AC circuit breaker at the onshore side. This means that
the converter will be out of service for a certain time and cannot be used as a STATCOM immediately after the fault. Nevertheless, a disconnector could be installed at DC side of the converter in order to isolate the faulty cable (in a second step) and re-start the converter as a STATCOM.

- The converter at DK onshore side are not connected at one same busbar. This means that the multi-terminal DC grid is radial and not meshed.

4.4.6.1 BUSBAR CONFIGURATION

In order to define the protection system components and layout it is necessary to first define a busbar configuration. It can be assumed that the choice of the busbar configuration mainly depends on the following analysis:

- A security analysis aiming to determine the acceptable risk of loss of load versus possible faults and failures.
- A cost analysis aiming to evaluate the cost (CAPEX) of the component as well as its unavailability.

To make a first selection of DC hub busbar configuration a qualitative security analysis shown in Table 47 has been made considering the following faults and failure:

- Line fault
- Busbar fault
- Line fault + breaker failure

Other possible faults and failures like busbar fault + breaker failure, security failure and dependability failure are not taken into account in the first qualitative analysis.

From Table 47 it can be seen that the busbar configuration has a major impact on the security operation of the DC hub when considering a busbar fault or line fault with a line breaker failure. Single Bus Single Breaker (SBSB) configuration is probably not acceptable to be implemented because a busbar fault (or a line fault + breaker failure) would entail a permanent loss of all the power transmitted through the DC hub, whatever the type of implemented fault clearing strategy is. It is the same in case of Ring busbar and line fault + breaker failure. For the same type of faults, the Double Busbar Single Breaker (DSDB) configuration would entail a temporary stop of one busbar when using a FS strategy, and a temporary stop of both busbars when using a NS strategy. For a Double Busbar Double Breaker (DBDB) configuration the same faults would keep a continuous operation when using a FS strategy and a temporary stop of both busbars when using a NS strategy.

The following choices have been made in order to further analyse the protection strategies:

- For FS fault clearing strategies, Double Busbar Double Breaker configuration is the chosen option because it allows "Continuous Operation".
  - Note that even in “Continuous Operation” there could be power oscillations that could impact the AC side. EMT simulations are probably required to identify AC transient stability issues (note that this AC system impact analysis was not performed).
  - To reduce the cost of double breaker, the multi-port breaker between two busbars could be an interesting solution (solution not analysed in this study).
  - The “one breaker and a half” configuration could also be a possible solution to reduce the cost but it would lead to a temporary stop of the DC hub in case of line fault + breaker failure. This solution has not been further studied.
For NS fault clearing strategies Double Busbar Single Breaker configuration is the chosen option.

- The use of NS strategies implies that temporary stop of power (higher than maximum LoI) is allowed.
- It is assumed that busbar reconfiguration time is automatic and fast (<100ms) and it is “hidden” within the intrinsic temporary stop of the NS fault clearing strategy.

<table>
<thead>
<tr>
<th>Table 47 Qualitative security analysis for busbar configuration choice</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Full selective</strong></td>
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<tr>
<td>Line Fault</td>
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<tr>
<td>Single busbar single breaker</td>
</tr>
<tr>
<td>Double busbar single breaker</td>
</tr>
<tr>
<td>Double busbar double breaker</td>
</tr>
<tr>
<td>One breaker and a half</td>
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<tr>
<td>Ring</td>
</tr>
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</table>

4.4.6.2 SELECTIVE FAULT CLEARING STRATEGIES

The protection components and layout for the FS strategies are shown in Figure 4-14. As already mentioned, the implemented busbar configuration for the FS strategies is the DBDB configuration. Line DC reactors are installed at the end of each line at the DC hub as well as at the converters output.
The detail of the protection sequences in case of line fault, busbar fault and line fault + breaker failure can be found in appendix 7.3.4. The DCCB and DC reactor design is shown in Table 48. The justification for DCCB and DCR reactor technical specification is presented also in appendix 7.3.4. For the calculation of energy absorption within the surge arrestors of the breaker the simplified formula proposed by WP6 is used (see PROMOTioN D4.7).

<table>
<thead>
<tr>
<th>Input parameter</th>
<th>Unit</th>
<th>FS - HDCCB</th>
<th>FS-MDCCB</th>
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<tbody>
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<td>Technology</td>
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<td>Hybrid</td>
<td>Mechanical</td>
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<td>Rated DC current</td>
<td>kA</td>
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<td>1.5</td>
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<tr>
<td>Rated Breaking current capability</td>
<td>kA</td>
<td>9</td>
<td>16</td>
</tr>
<tr>
<td>Rated DC voltage</td>
<td>kV</td>
<td>320</td>
<td>320</td>
</tr>
<tr>
<td>Rated transient Interruption Voltage (TIV)</td>
<td>p.u</td>
<td>1.5</td>
<td>1.5</td>
</tr>
<tr>
<td>Rated energy absorption</td>
<td>MJ</td>
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<tr>
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<td>ms</td>
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<td>mH</td>
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<td>Open-close operation</td>
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<td>Directionality</td>
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<td>Bi-directional</td>
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<tr>
<td>Rated short time withstand current</td>
<td>kA</td>
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### 4.4.6.3 NON-SELECTIVE FAULT CLEARING STRATEGIES BASED ON M-DCCB

The protection components and layout for the FS strategies are shown in Figure 4-15. The implemented busbar configuration for the FS strategies is the DBSB configuration. DCCB and Line DC reactors are installed at the end of each line at the DC hub as well as at the converters output. The busbar coupler is supposed to be a RCB (residual current breaker) in series with a DC reactor of 10 mH.
The detail of the protection sequences in case of line fault, busbar fault and line fault + breaker failure can be found in appendix 7.3.5. The DCCB and DC reactor design is shown in Table 49. The DCCB and DC reactor specification are justified by EMT calculation also presented in appendix 7.3.5.

It is worth to note that the main objective of DC reactor is to avoid very large short time current through the DCCB and RCB. A maximum value of short time current of 40 kA is assumed to be possible for the off-the-shelf technology.

Table 49 DCCB and DC reactor technical specifications for NS strategy based on M-DCCB

<table>
<thead>
<tr>
<th>Input parameter</th>
<th>Unit</th>
<th>NS - MDCCB</th>
</tr>
</thead>
<tbody>
<tr>
<td>Technology</td>
<td>Mechanical</td>
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</tr>
<tr>
<td>Rated DC current</td>
<td>kA</td>
<td>1.5</td>
</tr>
<tr>
<td>Rated Breaking current capability</td>
<td>kA</td>
<td>20</td>
</tr>
<tr>
<td>Rated DC voltage</td>
<td>kV</td>
<td>320</td>
</tr>
<tr>
<td>Rated transient Interruption Voltage (TIV)</td>
<td>p.u</td>
<td>1.5</td>
</tr>
<tr>
<td>Rated energy absorption</td>
<td>MJ</td>
<td>15 MJ (justified by EMT studies, see appendix)</td>
</tr>
<tr>
<td>Breaker opening time at maximum DC</td>
<td>ms</td>
<td>15</td>
</tr>
<tr>
<td>breaking current</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Current limiting DC reactor</td>
<td>mH</td>
<td>50mH in lines + 10 mH in bus coupler. (justified by EMT studies, see appendix)</td>
</tr>
<tr>
<td>Open-close operation</td>
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<td>O – C - O</td>
</tr>
<tr>
<td>Directionality</td>
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<td>Bi-directional</td>
</tr>
<tr>
<td>Rated short time withstand current</td>
<td>kA</td>
<td>40 kA</td>
</tr>
</tbody>
</table>
4.4.6.4 NON-SELECTIVE FAULT CLEARING STRATEGIE BASED ON FB-MMC

The protection components and layout for the FS strategies are shown in Figure 4-16. The implemented busbar configuration for the FS strategies is the DBSB configuration. DCCB and Line DC reactors are installed at the end of each line at the DC hub and at each converter output. The busbar coupler is supposed to be a RCB.

![Diagram showing protection components and layout for NS strategy based on FB-MMC](image)

The DCCB and DC reactor design is shown in Table 50. The DCCB technical specifications and the DC reactor at the converter output have been chosen based on the results presented in PROMOTioN deliverable D4.3. The DC reactor installed at line end at the DC hub is chosen in order to limit the short time withstand current at level lower than 40 kA.

<table>
<thead>
<tr>
<th>Input parameter</th>
<th>Unit</th>
<th>NS - MDCCB</th>
</tr>
</thead>
<tbody>
<tr>
<td>Technology</td>
<td>Mechanical</td>
<td></td>
</tr>
<tr>
<td>Rated DC current</td>
<td>kA</td>
<td>1.5</td>
</tr>
<tr>
<td>Rated Breaking current capability</td>
<td>kA</td>
<td>5</td>
</tr>
<tr>
<td>Rated DC voltage in open position</td>
<td>kV</td>
<td>320</td>
</tr>
<tr>
<td>Rated transient Interruption Voltage (TIV)</td>
<td>kV</td>
<td>80</td>
</tr>
<tr>
<td>Rated energy absorption</td>
<td>MJ</td>
<td>6</td>
</tr>
<tr>
<td>Breaker opening time at maximum DC breaking current</td>
<td>ms</td>
<td>8</td>
</tr>
<tr>
<td>Current limiting DC reactor in series with line DCCB</td>
<td>mH</td>
<td>15</td>
</tr>
<tr>
<td>Open-close operation</td>
<td>O - CO</td>
<td></td>
</tr>
<tr>
<td>Directionality</td>
<td>Bi-directional</td>
<td></td>
</tr>
<tr>
<td>Rated short time withstand current</td>
<td>kA</td>
<td>40</td>
</tr>
<tr>
<td>Current limiting DC reactor at MMC output</td>
<td>mH</td>
<td>10</td>
</tr>
</tbody>
</table>
4.4.7 AC HUB

Starting from the DC hub optimal solutions found by applying the methodology introduced in section 4.4.5, the equivalent AC hub options are derived. The difference between DC and DC hub solutions is related to the converter configuration at Bornholm level. In AC hub options, a converter with higher power capacity could be required at Bornholm node for some scenarios (e.g., 4200 MW should be installed in for the AC hub option in scenario 1b 600 MW allowed loss of infeed, see Figure 4-18). It should be noticed that even if more installed converter capacity is available at the AC hub, the installed wind power doesn’t exceed 3000 MW as it is defined in the scenarios introduced in section 4.4.5.

The single line diagram of scenarios 1a, 1b, 2a and 2b for AC hub configuration are depicted in Figure 4-17, Figure 4-18, Figure 4-19 and Figure 4-20 respectively.

![Single line diagram for AC hub at Bornholm node](image-url)
4.4.8 KPIS CALCULATION

A set of Key Performance Indicators (KPIs) for the evaluation of protection strategies have been presented in D4.3. In order to assess the protection strategies presented in 4.4.6 the following KPIs have been calculated:

- Performance indicators:
  - Active power restoration time, defined as the time span from the fault occurrence until the power flow of all concerned converters is restored at its post fault value and remains within a range of ±10% the nominal power. Longer is the power restoration time and higher could be the impact of the power disturbance on the transient and frequency stability of the AC system.
  - Reactive power restoration time, defined as the time span from the fault occurrence until the reactive power of all concerned converters is restored at its post fault value and remains within a range of ±10% the nominal power. It indicates how fast the converter can be activated to support the AC system voltage after a DC fault.

- Cost indicators:
  - CAPEX, which includes DCCB and DCR material costs, labor costs, indirect costs and site installation and commissioning costs. It is considered that all substations in Bornholm are onshore and therefore no extra cost due to offshore platforms have been taken into account. Cost model are derived from PROMOTioN data collection task for converters and cables, and extrapolation for more voltage and power ratings are made. The MV metallic return CAPEX is estimated by applying a factor of 0.33 of a HV cable (rated at the same transmitted power). For example, the metallic return CAPEX in Figure 4-10 is set to 0.33 multiplied by the 750 MW HV cable CAPEX. More details about the used cost models are given in appendix 7.3.2.1.
  - EENT, Expected Energy Non Transmitted. It has been calculated based on a typical power flow scenario including three hourly (8732 hours) time series and corresponding to 2025-2035, 2035-2045 and 2045-2055 horizon respectively. These hourly time series are derived from a market simulation. The calculated EENT indicator corresponds to the power curtailment when a failure occurs and equal to the difference between initial load flow (without failure) and the load flow after fault occurrence (with failure). More details about the used cost models, assumptions and data are given in appendix 7.3.2.1.
  - Losses. Losses are calculated for converters/transformers, cables and protection components:
    - Converter: SuperGrid Institute model
Cables: \( Rf^2 \) formula. Cable resistance is set to 1.1 ohm/100km for all type of cable (from PROMOTioN data, provided by WP12)

Protection strategy losses are derived from PROMOTioN DCCB cost model development. This includes inductor and DCCB losses

The active and reactive power restoration time are depicted in Table 51 and Table 52. The values depicted in the tables come from quantitative, as calculated in D4.3, and qualitative analysis of the protection sequences for line fault, line fault + breaker failure and busbar fault as shown in appendix 7.3.3.

Table 51 Active power restoration time

<table>
<thead>
<tr>
<th></th>
<th>Line fault</th>
<th>Line fault + breaker failure</th>
<th>Busbar fault</th>
</tr>
</thead>
<tbody>
<tr>
<td>FS, DBDB with hybrid DCCB</td>
<td>80ms*</td>
<td>85ms*</td>
<td>80ms</td>
</tr>
<tr>
<td>FS, DBDB with mechanical DCCB</td>
<td>110ms*</td>
<td>120ms*</td>
<td>110ms</td>
</tr>
<tr>
<td>NS, DBSB with mechanical DCCB</td>
<td>130ms*</td>
<td>130ms*</td>
<td>130ms</td>
</tr>
<tr>
<td>NS, DBSB with FB MMC</td>
<td>85ms*</td>
<td>85ms*</td>
<td>85ms</td>
</tr>
</tbody>
</table>

(*) In case of line fault on a rigid bipole (no metallic return, example line BH-Poland, scenario 2a 600 MW), the active power of the MMC connected to the line of opposite polarity will also be stopped.

Table 52 Reactive power restoration time

<table>
<thead>
<tr>
<th></th>
<th>Line fault</th>
<th>Line fault + breaker failure</th>
<th>Busbar fault</th>
</tr>
</thead>
<tbody>
<tr>
<td>FS, DBDB with hybrid DCCB</td>
<td>20ms *</td>
<td>25ms *</td>
<td>20ms</td>
</tr>
<tr>
<td>FS, DBDB with mechanical DCCB</td>
<td>35ms *</td>
<td>45ms *</td>
<td>35ms</td>
</tr>
<tr>
<td>NS, DBSB with mechanical DCCB</td>
<td>30ms *</td>
<td>45ms *</td>
<td>30ms</td>
</tr>
<tr>
<td>NS, DBSB with FB MMC</td>
<td>0ms</td>
<td>0ms</td>
<td>0ms</td>
</tr>
</tbody>
</table>

(*) In case of line fault, the Poland or DK2 MMC connected to the faulty line must open the AC breakers. As a consequence, the reactive power will also be stopped (temporary stop > 1s).

It can be noted that for the three type of faults there is not a big change on the restoration times. This is due to the busbar configuration, see 4.4.6.1, which benefits the restoration of the power in case of failure of the primary sequence.

Figure 4-21 and Figure 4-22 show respectively the DCCB (including DC reactor cost) unit costs for the different protection strategies and the total DCCB costs for the selected scenarios (2a and 1b with maximum loss of infeed
equal to 600 MW, 1a and 2b with maximum loss of infeed equal to 750 MW). The DCCB unit costs are calculated by means of the cost model developed within PROMOTioN WP4 and using input data parameters as shown in Table 48, Table 49 and Table 50. Furthermore, for the AC hub options the protection strategy CAPEX is neglected since we don’t need a protection within the DC grid (the protection is insured by the AC circuit breaker installed in either case). Figure 4-23 shows the total CAPEX including protection strategy (DCCB and DCR), cables and converters; the percentage of the contribution of the protection strategy for the total CAPEX is also shown in the figure. Some general remarks are stated hereunder:

- The hybrid DCCB unit cost for onshore installation is around 8 M€ in scenario 1a while it is around 9 M€ for scenarios 1b, 2a and 2b.
- Unit cost of mechanical DCCB for the FS strategy is around 3.5 M€ while the cost of mechanical DCCB for the NS strategy is around 5 M€. The difference comes from the breaking capability, respectively 16 kA and 20 kA, and a threshold effect within the DCCB cost model.
- Mechanical DCCB for NS strategy using FB-MMC is lower than 1 M€ because of the lower breaking capability and the TIV requirements.
- The total DCCB cost for the FS strategies using hybrid DCCB is the highest one, this is also due to the busbar configuration which requires double breakers configuration. As already mentioned, solution could be developed in order to reduce the DCCB cost, for example using multi-port hybrid breakers.
- The percentage of the contribution of the protection strategy into the total CAPEX (cable + converter + DCCB) lays between 4% and 15%. Moreover, there is no big difference of results depending on the selected scenario.
- Full selective with hybrid DCCBs and full bridge protection strategies seem to be less interesting from CAPEX point of view comparing to NS protection strategies and AC hub options.
- For scenarios 1b (Figure 4-22 (b)), 2a (Figure 4-22 (c)) and 2b (Figure 4-22 (d)), AC hub options have slightly higher CAPEX comparing to full selective and non-selective with mechanical DCCBs although an extra CAPEX due to the protection equipment is needed in DC hub options. This is due to the fact that a more converter power capacity in Bornholm node is needed (which leads to a converter extra costs).
- For scenario 1a (Figure 4-22 (b)), AC hub option have a lower CAPEX comparing to DC hub one. This is due to the fact that there is no extra cost for converter in this scenario. However, installing 3000 MW in 2026 at Bornholm node is needed while in DC option 2000 MW and 1000 MW are installed in 2026 and 2028 respectively.
Figure 4.21 CAPEX calculation: a) for scenario 1a (maximum loss of infeed of 750 MW, rated voltage 400 kV), b) Scenario 1b, 2a (maximum loss of infeed of 600 MW, rated voltage 320 kV) and 2b (maximum loss of infeed of 750 MW, rated voltage 320 kV) – DCCB and DCR

Figure 4.22 CAPEX calculation: a) for scenario 1a (maximum loss of infeed of 750 MW, rated voltage 400 kV), b) Scenario 1b, 2a (maximum loss of infeed of 600 MW, rated voltage 320 kV) and 2b (maximum loss of infeed of 750 MW, rated voltage 320 kV) – Total protection equipment cost
CAPEX calculation: a) for scenario 1a (maximum loss of infeed of 750 MW, rated voltage 400 kV), b) Scenario 1b, 2a (maximum loss of infeed of 600 MW, rated voltage 320 kV ) and 2b (maximum loss of infeed of 750 MW, rated voltage 320 kV ) – Total cost

As it is explained in 4.4.3.2, the metallic return in bipolar configurations could be mutualized. The main reason is to reduce the cost of installed metallic returns if several bipoles are needed without having more impact on the availability of the interconnection. In order to justify the use of one metallic return instead of several ones, expected energy not transmitted EENT is calculated for the configuration with one metallic return (1xMR) and two metallic returns (2xMR) for different scenarios (except for scenario 1a in which the optimal solution is a one bipolar configuration for both Bornholm-Denmark and Bornholm-Poland interconnectors) and protection strategy schemes. The results are depicted in Figure 4-24 (a), (b) and (c). For the sake of simplicity, it should be noted that the EENT in the following figures are given as a power loss (in MW). So, to compute a real EENT these values should be multiplied by the time horizon (by 8732 and by number of years).

Figure 4-24 shows that using one metallic return (MR) instead of two MR, the expected energy not transmitted is practically not deteriorated. Indeed, the maximum EENT gain is for the scenario 1b (Figure 4-24 (a)) which is around 1 MW (around 1.5% of the EENT in configurations 1xMR). This gain seems to be not significant if we look at the additional CAPEX due to the second metallic return (around 85 M€ in scenario 1a and 50 M€ in scenarios 2a and 2b). Consequently, using a mutualized metallic return seems to be a good cost saving approach.
Figure 4.24 Impact of the metallic on total power loss (both EEN and losses): a) Scenario 1b (750 MW LoI), b) Scenario 2a (600 MW LoI) and 2b (750 MW LoI).

Figure 4.25 shows expected energy not transmitted (EENT) (left) and losses (right) for scenarios 1a, 1b, 2a and 2b and for different protection strategies and hub options. Following conclusions could be drawn from this figure:

- Losses due to converters, transformer, cables, DCCBs and reactors are more important than the EENT. Depending on the scenario, the EENT are around 18% of the losses (13% for scenario 1a). So, the losses are a more differentiable criterion when comparing AC and DC hub options.

- Calculations show more losses in AC hub compared to DC one (except for non-selective full bridge protection strategy which has higher losses due to the full bridge converter). For instance, the losses in DC hub option for scenarios 1a are around 52 MW while the losses in AC hub option are around 59 MW. This is mainly due to the additional converter losses when the interconnectors are used to exchange power between Denmark and Poland. However, when the exchanged power between Denmark and Poland is low, the losses tend to be quite similar (in scenario 2a, losses in DC and AC hub options are around 44 MW and 46 MW respectively). This is why more difference can be observed in scenarios 1a and 1b which have a quite high exchanged power between Denmark and Poland comparing to scenario 2a and 2b.

- The EENT in AC options is higher than the DC options in scenarios 1a, 2a and 2b. This is due to the fact that exchanging power between Poland and Denmark requires the availability of more components in AC hub options. The larger the power exchange between Poland and Denmark is, the larger the EENT is (scenario 1a). However, in the case of high additional installed converter power capacity in Bornholm (scenario 1b, 4200 MW), the difference between AC and DC options will tend to be low because of higher value of converter redundancy at Bornholm node.
The contribution of the protection strategy to the total EENT and losses is very low.

Figure 4-25 Expected Energy Not Transmitted EENT (left) and losses (right) : a1 - a2) Scenario 1a, b1 - b2) Scenario 1b, c1 - c2) Scenario 2a, d1 - d2), Scenario 2b
4.4.9 EXTENSIBILITY

In order to compare the “extensibility” future of the DC and AC hub options, the interconnections between Bornholm - Sweden (SW) and Bornholm - Germany (DE) are used (Figure 4-3). Different interconnector capacities are taken into account. Following assumptions are made:

- All combinations of installed power of 0 MW, 600 MW, 1200 MW and 1800 MW in both SW and DE nodes are simulated.
- The allowed loss of infeed (LoI) 600 MW, 750 MW and 900 MW are considered.
- The distances between Bornholm and Sweden and Bornholm and Germany are set to 50 km and 135 km respectively.
- The adopted interconnector configurations are assumed to be as follows:
  - **Installed power = 600 MW.** A Rigid bipole (without MR) is used for all allowed loss of infeed.
  - **Installed power = 900 MW.** A classical bipolar (with MR) is used for LoI of 600 MW and 750 MW. For LoI of 900 MW, a Rigid bipole (without MR) is used.
  - **Installed power = 1200 MW.** A classical bipolar (with MR) is used for all allowed loss of infeed.
  - **Installed power = 1800 MW.** Two rigid bipoles with a mutualized metallic return are used for LoI of 600 MW and 750 MW. For LoI of 900 MW, a classical bipolar (with MR) is used.

Figure 4-26 and Figure 4-27 show the total CAPEX (including initial hub CAPEX, additional cables, converters and protection equipment CAPEX) of the extended hub for the scenario 1a (750 LoI) and 2b (750 LoI) respectively. Figures (a), (b), (c) and (d) correspond to pair of installed power in Sweden and Germany (0 MW, 600 MW), (0 MW, 1200 MW), (1200 MW, 1200 MW) and (1800 MW, 1800 MW) respectively. The initial CAPEX values in these figures, without extension, are in blue colour. Same results for 1b (600 LoI) and 2a (600 LoI) are shown in Figure 7-16 and Figure 7-17 respectively. Following conclusions can be drawn from Figure 4-26 and Figure 4-27:

- The additional CAPEX in AC hub option is higher than the DC hub option. This is due to the fact that additional converter power capacity in Bornholm node is required in AC hub option.
- The higher is the installed capacity to Sweden and Germany, the higher the additional CAPEX in AC hub option is compared to the DC option. For instance, the difference between the CAPEX in the cost effective solution in DC hub option and the AC option is around 86 M€ if 0 MW is installed in SW and 600 MW in DE, while this difference becomes 443 M€ if 1800 MW is installed in both SW and DE nodes.
- The difference between the CAPEX in AC and DC options tends to be reduced when the allowed loss of infeed is high. This is shown in Figure 4-28 which represents the additional CAPEX per installed power in SW and DE in case of 320 kV voltage rating. Indeed, the CAPEX difference between AC and DC options is around 401 M€ (see Figure 4-28 (b)) in case of 750 MW allowed loss of indeed while the difference becomes 367 M€ in case of 900 MW LoI (see Figure 4-28 (c)). This is due to the fact that a gain in terms of additional installed converter capacity is observed in case of 900 MW LoI.
- The results for 600 MW and 750 MW LoI in Figure 4-28 (a) and Figure 4-28 (b) are the same, which is due to the fact that the same solutions (configurations) are used in both cases.
- The difference between the CAPEX in AC and DC options tends to be increased when the voltage rating is high. This is shown in Figure 7-18 which represents the additional CAPEX per installed power in SW and DE in case of 400 kV voltage rating. Indeed, the equipment (cables, converters and protection equipment) are more expensive for high voltage rating.
Additional CAPEX for extended hub, scenario 1a 750 allowed loss of infeed:

- a) Extended power in SW=0 MW and in DE=600 MW,
- b) Extended power in SW=0 MW and in DE=1200 MW,
- c) Extended power in SW=1200 MW and in DE=1200 MW,
- d) Extended power in SW=1800 MW and in DE=1800 MW

Additional CAPEX for extended hub, scenario 2b 750 allowed loss of infeed:

- a) Extended power in SW=0 MW and in DE=600 MW,
- b) Extended power in SW=0 MW and in DE=1200 MW,
- c) Extended power in SW=1200 MW and in DE=1200 MW,
- d) Extended power in SW=1800 MW and in DE=1800 MW
Figure 4-28 Additional CAPEX for extended hub reference and different installed powers in SW and DE (320 kV):

a) Loss of infeed 600 MW, b) Loss of infeed 750 MW, c) Loss of infeed 900 MW
4.5 MARKET SIMULATIONS

The main new concept related to market arrangements that could be implemented in the Bornholm project is the creation of an offshore bidding zone around the hub. In this way windfarms connected to the island would not bid into the DK2 market area but would have a separate bidding zone which is then interconnected with DK2 and PL. The legal and business implications of offshore bidding zones have been extensively reviewed in the main Deliverable D12.4, section 4.5. In short, the conclusion is that a market design for a MOG that consists of offshore price zones that are separated by congested transmission links provides for an economically efficient dispatch of wind generation, economically efficient incentives for energy storage and power-to-X, maximises cross-border power flows and avoids counter-intuitive flows (from higher to lower price zones). The default solution of extending national price zones into the EEZs in the North Sea or a single offshore price zone does not meet all these criteria. Therefore, PROMOTioN has generally recommended to implement the offshore price zones model for offshore wind power generation.

For this specific case, the effects of introducing a separate bidding zone were investigated in a realistic future market setting, to answer the following two questions:

1. How do different interconnector capacity options affect the economic situation of the system and the different actors?
2. How does creating a separate bidding zone around the new Bornholm offshore hub affect the flows and revenues of the different actors?

To answer these questions, 'representative' scenarios were created and optimised in an energy system model. Market simulations that PROMOTioN has performed have analysed 4 scenarios with different grid capacity and bidding zone arrangements and compared socio-economic surplus distribution. The four analysed scenarios are based on the Danish offshore wind plan to integrate 3 GW of wind around Bornholm, and on TYNDP indicating potential 0.6 GW of interconnecting capacity between Poland and Denmark:

1. Bornholm as a part of DK2 bidding zone. Bornholm to Poland capacity is 0.6 GW, Bornholm to Denmark Capacity is 3.6 GW.
2. Bornholm as a separate bidding zone. Bornholm to Poland capacity is 0.6 GW, Bornholm to Denmark Capacity is 3.6 GW.
3. Bornholm as a part of DK2 bidding zone. Bornholm to Poland capacity is 1.5 GW, Bornholm to Denmark Capacity is 1.5 GW.
4. Bornholm as a separate bidding zone. Bornholm to Poland capacity is 1.5 GW, Bornholm to Denmark Capacity is 1.5 GW.
The analysis was made using energy system model Balmorel. Balmorel is a partial equilibrium model for analysing socio-economically optimised scenarios of the energy system with multiple energy carriers and technologies in an international perspective. The model is coded in a model language, and the source code is readily available under open source conditions. It is highly versatile and may be applied for long range planning as well as shorter time operational analysis. Balmorel is implemented as a mainly linear programming optimisation problem. We applied a three step optimization, for 1) investment optimisation of the future European energy system, 2) optimisation of storage utilisation, and 3) day-ahead dispatch modelling for all power and heat units on the integrated energy markets, with most detailed modelling in the Nordics (Scandinavia plus adjacent countries). The main assumptions of the model and resulting characteristics of the European energy systems are given in section 7.3.1.

Analysing relevant indicators and aggregating them into overall system measures allowed to assess impact of different choices measured as difference between the redistribution of surpluses under the selected scenarios. We used as metrics: producer surplus (revenues from electricity sold net of its production costs), consumer surplus (procured energy), congestion rents (product of price difference and power flows in congested lines) and CO2 emission reduction.

4.5.1 RESULTS. ELECTRICITY FLOWS AND PRICES

The model simulations reveal a substantial flow of electricity over the transmission lines, mostly into the direction of Poland. Note that we model full park operation from the year 2025. For example, Table 53 shows the results for scenario 4 where we have 1.5 GW interconnection to both Poland and Denmark and a separate bidding zone, we see 50-80% higher flow to Poland as compared to Denmark. Also, there is substantial flow from Denmark through the hub to Poland.

<table>
<thead>
<tr>
<th>Year</th>
<th>DK2-BH</th>
<th>BH-DK2</th>
<th>BH-PL</th>
<th>PL-BH</th>
</tr>
</thead>
<tbody>
<tr>
<td>2025</td>
<td>1,738</td>
<td>6,197</td>
<td>9,593</td>
<td>372</td>
</tr>
</tbody>
</table>
These flows are of course mostly related to the prices in the different market areas. The prices resulting from the optimisation model in the four different scenarios are all relatively stable, with some decrease over time, as can be seen in Table 54. One can conclude that the price of the hub is very close to DK2 price zone and that the price in Poland is consistently approximately 10-15% higher.

Table 54 Simulated market prices in the four scenarios

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Year</th>
<th>DK2</th>
<th>BHUB1</th>
<th>PL</th>
<th>TOTAL SYSTEM</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.5/1.5 GW BH own market zone</td>
<td>2025</td>
<td>40.31</td>
<td>40.16</td>
<td>44.77</td>
<td>40.12</td>
</tr>
<tr>
<td></td>
<td>2035</td>
<td>37.46</td>
<td>37.22</td>
<td>42.80</td>
<td>37.71</td>
</tr>
<tr>
<td></td>
<td>2045</td>
<td>36.36</td>
<td>36.27</td>
<td>42.77</td>
<td>36.92</td>
</tr>
<tr>
<td>3.6/0.6 GW BH own market zone</td>
<td>2025</td>
<td>40.41</td>
<td>40.24</td>
<td>44.76</td>
<td>40.14</td>
</tr>
<tr>
<td></td>
<td>2035</td>
<td>37.56</td>
<td>37.43</td>
<td>42.84</td>
<td>37.74</td>
</tr>
<tr>
<td></td>
<td>2045</td>
<td>36.40</td>
<td>36.31</td>
<td>42.85</td>
<td>37.05</td>
</tr>
<tr>
<td>1.5/1.5 GW BH in DK2</td>
<td>2025</td>
<td>40.56</td>
<td>40.56</td>
<td>44.80</td>
<td>40.17</td>
</tr>
<tr>
<td></td>
<td>2035</td>
<td>37.41</td>
<td>37.41</td>
<td>42.80</td>
<td>37.73</td>
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<tr>
<td></td>
<td>2045</td>
<td>33.88</td>
<td>33.88</td>
<td>40.27</td>
<td>34.20</td>
</tr>
<tr>
<td>3.6/0.6 GW BH in DK2</td>
<td>2025</td>
<td>40.39</td>
<td>40.39</td>
<td>44.75</td>
<td>40.15</td>
</tr>
<tr>
<td></td>
<td>2035</td>
<td>37.53</td>
<td>37.55</td>
<td>42.81</td>
<td>37.75</td>
</tr>
<tr>
<td></td>
<td>2045</td>
<td>33.78</td>
<td>33.78</td>
<td>40.20</td>
<td>34.16</td>
</tr>
</tbody>
</table>

* The moderate drop in prices for 2045 in the integrated DK2 bidding zone may be related to modelling effects – we could not establish that this should be systematic – the uncertainty in the future system is high.

We would like to stress here that we made a socio-economic evaluation and considered equilibrium market prices on day-ahead markets only. The results do not fully reflect actual spot market price formation and cannot predict the profitability of any options for commercial market actors.

Having said that, it is interesting to have a look at the hourly price structures in the scenarios. We find that over time, high prices become higher and low prices become lower. A greater price variability is expected in 2035 and 2045 with more frequent extreme prices. In 2045, we see a considerable number of zero-price hours in the system. Note that our model does not operate with negative prices. We can also confirm a respective amount of voluntary curtailment by wind production in some of these zero-price hours. There are no visible differences between the different interconnection capacity scenarios, so these are structural system effects unrelated to the size of one interconnector in the system.
4.5.2 RESULTS. INCREASING TRANSMISSION CAPACITY.

The analysis on interconnector capacity was modelled so that it compares a situation that we can call the ‘traditional’ approach, i.e. where all park production in principle could be transported to the home country, with a situation in which the connection to the home country is limited.

A main expected effect is that with increased interconnector capacity also the interconnector flows increase, and so do the TSO revenues. The impact on the Bornholm hub wind park operator is in a minor negative direction, with exception for the short term in a situation in which the park is part of DK2. Here, DK2 will experience slightly increasing prices due to the improved interconnection to Poland where prices are higher. The model simulation, however, foresees this effect to be levelled out in 2035 already.

Another interesting effect to be seen is that the higher interconnection capacity seems to lead to a slight decrease in the region surplus (the region consisting of: Denmark, Bornholm hub, Poland) in the short term, although Danish surplus increases. This is due to a shift in overall production patterns, decreasing electricity prices in the region, increasing heat prices in Poland, and some export of surplus to other regions, due to what can be interpreted as inflexibilities especially in the Polish energy system. Over the next ten years, this effect seems however reversed, and we see investment in more flexible and sector-integrating technology options (especially power-to-heat) also in Poland, partly triggered by the access to less expensive electricity through the interconnection.

When comparing the base case (3.6 GW to DK2, 0.6 GW to PL) to the 1.5/1.5 GW hybrid asset, we see:
- Congestion rents are higher in the 1.5/1.5GW scenario, where there is more interconnection capacity to Poland.
- Losers and winners depend very much on the overall system (generation mix, electrification, level of interconnection, etc) - and this might change over the years.
- Sector coupling, and especially the capacity to flexible utilisation of cheap electricity in the heat sector through power-to-heat solutions has a strong influence on surplus outcome.

Below is an overview of surplus distribution in different years with the change in capacity from 1.5 GW in both directions to 3.6 GW from Bornholm to Denmark and 0.6 GW to Poland. In these figures PS EL stands for producers of electricity, PS HE – producers of heat, CS EL – consumers of electricity, CS HE – consumers of heat and CR – congestion revenue.

![Figure 95 Surplus distribution. Changing transmission capacity. 2025.](image-url)
4.5.3 RESULTS. CREATING OFFSHORE BIDDING ZONE.

This section explains how introducing a separate offshore bidding zone around Bornholm energy hub will affect the distribution of surplus in the region in the very short term (2025) (assuming that the wind park could be fully operational at that time) and medium term (2035) for the two asset designs described in Figure 66.

The effects of introducing a bidding zone for the Bornholm offshore hub (BHUB) are similar for both transmission line cases – therefore we only discuss the results for the 1.5 GW / 1.5 GW interconnection option here. What we can see is that in the short term as well as in the medium term, we find as expected a reallocation of surplus from the Bornholm offshore wind park towards the transmission system operators. As described earlier, the price formation principles in the new bidding zone are such that the wind park will always receive the lower price of the two adjacent market areas, and sometimes even less. What is interesting is that the prices in the hub seem to be able to remain relatively stable over the whole lifetime of the offshore wind park, albeit somewhat lower than in the adjacent markets. The Bornholm hub wind production losses in the first simulated year of production (2025) ca. 5% of its revenues compared to a situation in which the park would be part of the DK2 market area, and ca. 7% in the medium term (2035). This loss by the wind park is mostly gained by the TSO through congestion rents.

As with the increase of interconnection capacity, we see that the introduction of the separate bidding zone seems to lead to a slight decrease in the region surplus in the short term, although Danish surplus increases. This is also due to a slight shift in overall production patterns, decreasing electricity prices in the region, and some export of surplus to other regions. Again, over the next ten years, this effect seems reversed, and we see Poland to benefit from the new market arrangement in the medium to long term.

When comparing the situation where the offshore wind farm is part of DK2 to the situation where it has its own bidding zone, we see:

- Overall very limited system changes
• The offshore wind park in the Bornholm hub loses some revenues due to lower prices in the separate bidding zone.
• TSOs gain from increased interconnector flows and connected congestion rents.
• Price differences caused by the separate bidding zones also affect capacity investments in both systems.
• Poland consumer surplus sees the strongest impact of an offshore bidding zone introduction. (Spillover effects from electricity to heat system due to market integration through heat pumps).

Delta Agents Surplus from 3.6,0.6 GW to 1.5,1.5GW - 2025

Delta Agents Surplus from 3.6,0.6 GW to 1.5,1.5GW - 2035

4.5.4 OVERALL CONCLUSIONS

Overall, we can conclude that
- A balanced interconnection (e.g. 1.5 / 1.5 GW to both DK2 and Poland) from the hub minimises system cost and increases the surplus in the region (in comparison to connecting the full hub capacity to DK2)
A new bidding zone around the Bornholm hub implies a reallocation of surplus from the wind farm owner to the TSO, as prices in the hub would be lower than in DK2 – but the effect seems to be very small, even further into the future. Model results find prices in the hub to be stable, only slightly below the adjacent markets (1-7%).

Consumers or producers in Denmark are not expected to be negatively influenced from the increased interconnection to Poland or the creation of a bidding zone.

Most of the energy produced in the hub will flow into Poland. Systems effects are most significant in Poland – with inconclusive results (some positive, some negative). It is not possible to point to clear winners and losers in the adjacent countries – this will highly depend on the adaptability of the market actors to benefit from the new situation and the ability to integrate between electricity and heat sectors (e.g. invest in power-to-heat solutions, storage etc.). It is recommended to investigate the effects further under different generation and load scenarios, and transmission capacities.

4.6 CHANGE PROCESS FOR THE MAXIMUM ALLOWED LOSS OF INFEED IN DK2

In section 4.4 we have shown that there are multiple ways to deliver the same transmission capacity from Bornholm to Poland and Denmark. Whether implemented as AC or DC hub, there are multiple combinations of cable capacities at different voltages that would result in the same net transmission capacity of the corridor. There are however limitations as to have large a single HVDC link connected to Denmark can be. These limitations are established in order to protect the power system from a situation when large amount of power infeed is suddenly lost. Such a sudden loss can significantly jeopardize the entire power system and lead to a situation where either consumers would be disconnected, or to prevent this the TSO has to cover sudden imbalance by buying manual frequency restoration reserves (mFRR).

The size of maximum allowed loss of infeed (LoI), and mFRR, is determined by the size of the largest generation unit or HVDC cable in the system. Danish power system is divided into two market zones – DK1 (western part) and DK2 (eastern part). Maximum allowed loss of infeed in DK1 was increased to 700 MW with the commissioning of SK4 HVDC-VSC link between Denmark and Norway in 2014, which is of 700 MW capacity. In DK2 the largest unit is 600 MW.

From the point of view of minimizing project CAPEX, we have shown that larger cables are more beneficial for all scenarios, however at the capacities which exceed currently established 600 MW allowed LoI in DK2. (The only exception is Scenario 1b - 2.1 GW built in 2026 in each direction, where the costs are identical between 600 /750 and 900 MW LoI and only 4% higher than the overall cheapest solution). When a TSO increases their maximum loss of infeed, due to e.g. connection of new HVDC link or having larger generation unit installed in the system, it is usually also increasing the amount of mFRR that has to be purchased on a daily basis. This increases the operational costs of running the power system, which reflects on the consumers. Thus, the compromise is between CAPEX savings from larger cables, vis-à-vis increased lifetime OPEX from the procurement of mFRR. The latter can be computed as the total annual OPEX during the project lifetime discounted to the base year when capital investment is made.

It is difficult to obtain a good projection of what the mFRR costs will look like in DK2 during the project lifetime (from 2030 onwards). Therefore, PROMOTiOn has not directly performed this comparison. Nevertheless, we suggest that project developers of Bornholm Energy hub should conduct additional studies in this direction as our topology designs have shown that increased LoI might be beneficial. We also note that sometimes countries (and TSOs) share their reserves, which for example is the case today with Sweden and DK2. This means that reserves do not necessarily have to be procured locally and small systems such as DK2 can make use of mFRR located in the neighbouring zone.

PROMOTiOn experts have outlined a general procedure which would have to be followed by project developers and / or Danish TSO Energinet in order to re-consider the current DK2 LoI of 600 MW. Note that the below
description, albeit being discussed with several TSO experts, is a high-level overview and not a formalized procedure that would be followed in a real life.

As this concerns only a change in Denmark, no other parties from the neighbouring countries have to be involved. The main issue is the internal approval process which would generally be part of the business case process for the entire project, in this case the overall Bornholm project. This would entail a socioeconomic comparison of the project respecting the current dimensioning incident (600 MW) with a higher dimensioning incident (e.g. 750 MW). In this comparison, future connection of offshore wind in DK2 would most likely be included as well, such if we were to anyway increase the dimensioning incident to e.g. 750 MW due to other offshore wind farms being connected. The “time effect” should be included in the Bornholm business case if e.g. the higher level is realized in 2030 instead of 2040. There is no formal process as such, but it will be part of the business case process. Once the decision is made, more or the less, the only necessary change will be increasing the procurement of frequency restoration reserves (FRR) once the new system comes into operation.

As such the procedure does not require the change of Danish grid codes. The System Operation Guideline stipulates certain reserve requirements which are ultimately laid down in the load frequency control (LFC) Block Agreement for the Nordic LFC block and/or the Nordic Synchronous Area Operational Agreement. It is expected that the general reserve dimensioning methodology would simply accommodate new numbers and calculate a new reserve dimensioning. It might be the case, however, that the methodology as such would need to be updated, but it ought not to be the case. This is a lengthy process which in the first step involves the Nordic TSOs, who draft an amendment to the existing methodology, which must then be approved by the Nordic Energy Regulators. It might take between 2 or more years but considering a project to be realized after 2025, it should not be an issue as this could be done in parallel to construction.

The decision as such to change the dimensioning incident is purely a national decision. However, since it will have consequences for the LFC block and/or the synchronous area, changes would be needed in the block and/or synchronous area operational agreement or at least new calculations based on the existing methodologies would be needed. The latter should not be too complex, and the main issue would be if the new dimensioning incident is seen to be such a fundamental change that the whole Nordic system that a whole new methodology was needed. That would of course tend to make the process longer, but a 2-3- year horizon still ought to be enough.

4.7 SUPPORT SCHEME DESIGN

Whether the island of Bornholm will constitute a separate bidding zone or will be treated as a part of DK2, renewable energy generated by OWFs around the island will flow to Poland, when the wholesale price for electricity in Poland is higher than in Denmark (As is expected to be the case by market modelling described in section Error! Reference source not found., and validated with DNV GL in-house wholesale power price forecast). These results are dependent on the assumptions concerning demand in the two zones, where the present analysis has not included introduction of e.g. large PtX facilities to the landing zones, which could imply major changes in flows and prices resulting from the project. Specifically, plans to construct a large PtX plant in DK2 in close proximity to the landing point of the connection to the Bornholm project has been announced by a consortium of major Danish companies5. While having an OWF supplying renewable power to adjacent markets is principally no different from an offshore wind farm connected radially to a market, which is then connected to another higher priced area. The direct link between the OWF and the two markets could open discussion over the

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possibility of both Polish and Danish governments providing support schemes to these windfarms. This could make use of the statistical transfer tools available under European law. Although this is a mainly political discussion, PROMOTioN has analysed possible ways to involve both Denmark and Poland in supporting the construction of OWFs around Bornholm.

One of the options is to use a cooperation mechanism, such as a Joint Support Scheme or a Joint project. A joint support scheme is an alternative to national renewable support schemes. The participating countries develop a single support scheme applied to all shared assets. A detailed description along with guidance for implementation of joint support schemes has been published by the European Commission [33]. Whereas joint support schemes envisage long-term cooperation over multiple tenders, a Joint Project can be used if only one project is envisaged. PROMOTioN WP 7 D 7.9 (section 9.8) has mentioned that in certain situations Joint Support Scheme, Tenders and Joint Projects can facilitate more optimal deployment of infrastructure [19]. Such cooperation mechanisms imply that countries carry a Joint Tender for the construction of OWFs in Danish Exclusive Economic Zone (EEZ).

There is an existing EU legal framework to design such a scheme and to divide the benefits. A clear “distribution rule” designed in advance would have to prescribe in which proportion the countries will allocate their own resources to finance the scheme. If both countries decide to provide support to Bornholm OWFs, support schemes for the tender would have to be adjusted to reflect this allocation. Similar conditions for participation, same running time and aligned tender procedure would have to be ensured.

As a part of the joint tender, OWF developers would have to bid for a construction of certain generation capacity, specifying the minimum amount of support they need to implement the project. If current Danish form of support is followed, i.e. a double-sided Contract for Difference (CfD), a certain strike price per MWh of electricity produced would be provided to generators. If the market price of electricity is below the strike price, the support scheme would compensate the difference to generators, while wind turbine owners would pay back if the market price of electricity is above the strike price.

In the situation where wind farms bid in their own offshore bidding zones, the costs of a CfD scheme to the country(ies) involved will increase. This effect arises because offshore bidding zones would in theory lead to lower market income received from the OWF (although PROMOTioN market studies for Bornholm have shown that the effect is not as strong, it is worth to investigate this issue further under different generation scenarios and capacities; for additional elaboration on the effect of small offshore bidding zones refer to Appendix V of the D12.4 Deployment Plan). A characteristic feature of offshore bidding zones is that the distribution of socio-economic welfare shifts, such that OWFs get lower revenues, while TSOs get higher congestion rents. In order to account for this effect, one option could be for generators to be provided with a form of an option or transmission rights (note that this is different from traditional FTRs) corresponding to a predefined share of the interconnector capacity by the market operator. These options could be allocated as a part of the tender for the OWF.

A holder of an option in a given hour will receive income corresponding to the price difference between the two price zones in that given hour (i.e., the congestion rent). Owner of the wind farm would hold options to sell energy in both directions and is free to decide where it is more beneficial to market the energy. The transmission owner, who is the counterpart for the contracts, should ensure that the volume of the option contracts (in MW) does not exceed the volume of grid capacity that he can reliably provide. The effect of this arrangement is that the wind farm operators receive an additional income that can be a proxy for onshore prices, but only for the volume of generated energy that can be evacuated. However, as the allocation (and hence the income) of the FTR is not dependent on offshore wind production in a given hour, it will remain a proxy unless a methodology of dynamic allocation of FTRs is found. In case of a need for curtailment, the excess supply in the offshore price zone will...
cause the price in the offshore zone to drop to zero. This would make the wind farm operators indifferent to being curtailed for the volume of generation that is not covered by the options. It is up to the OWF owner to decide where to market the electricity, between boundaries of the line capacity. Probably such a decision would be driven by the price difference between DK and PL. Finally, generated renewable energy would count as generated in the country where it is marketed (counts towards target "national reference points"). An exact arrangement in terms of quantities of options in the direction from Bornholm hub to DK and to PL needs to be further investigated and is ultimately a political decision. PROMOTioN has not undertaken any assessment on the exact design of such scheme, number of options, potential to couple them with CfD, and allocation rules that would ensure solid support to OWF, while at the same time not distorting the market. Nevertheless, we see this as a viable option that needs to be further analysed.

4.8 OWNERSHIP MODELS

The development of a meshed offshore grid (MOG) is capital intensive and requires investment models and structures, that can anticipate and fund the required cross-border investments. Innovative asset ownership models could potentially facilitate faster roll-out of offshore grids by providing more private capital and releasing the pressure on the state in financing grid deployment. Bornholm project is a single-short-term project that is identified as contributing to Danish government's goals to accelerate wind deployment [34]. Hence, it is likely that much of the infrastructure in this project could be financed by public capital as it will probably fall into regulated transmission assets.

As the project outside Bornholm is the first of its kind, the availability of private capital might not be the main driver for delivering Bornholm energy hub. Within PROMOTioN, possible options for ownership for Bornholm hybrid project have been explored and evaluated taking into account the views of stakeholders in the PROMOTioN project. The ownership models were assessed against a set of criteria which can allow the identification of the features that would facilitate the efficient delivery of the project. Which model will be most appropriate for the Bornholm project is ultimately a political decision. The study presented below aims at a qualitative comparison of different options and has been performed based on the input of involved project partners.

A schematic representation of the different parts of the project is given in Figure 4-99:

- According to the current Danish legislation, the connections of the OWFs to the hub on Bornholm (onshore substation) could be part of the OWFs (or at least are not considered part of the transmission network). In the scope of the latest Danish project, Thor, the connector from OWF to grid will be constructed and owned by the OWF developer [35].
- The line from DK2 to Bornholm hub could be either part of the Danish transmission grid or, if the line from DK2 to Poland is considered one asset, could be classified as an interconnector.
- Finally, the line from Bornholm hub to Poland is classified as interconnector.

In this section, possible ownership models for the hybrid project i.e. cable from DK2 to Poland including the hub on Bornholm, which aims at evacuating the offshore wind to the shore and trading energy between the countries are shown. It is noted that a differentiation has to be made between legal ownership and economic ownership. Although the legal owner and economic owner is in most cases the same (legal) person, there is a difference. The legal owner is the person recognized in law to own the asset or good in question. The economic owner is the person who exercises control over the asset and ultimately benefits from its use [16]. Also, the economic ownership can be transferred. This chapter refers to economic ownership only.
Table 55 gives an overview of the investigated ownership models and the distribution of responsibilities for the grid activities. It is noted that under all models the system operation remains responsibility of the TSO.

Table 55 Bornholm energy hub. Ownership models.

<table>
<thead>
<tr>
<th>Model</th>
<th>Construction</th>
<th>(Economic) Ownership</th>
<th>Repair &amp; Maintenance</th>
<th>System operation</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>TSO model</td>
<td>TSO</td>
<td>TSO</td>
<td>TSO</td>
</tr>
<tr>
<td>B</td>
<td>OWF developer</td>
<td>Transmission assets transferred to TSO/third party (competitively appointed transmission owner)</td>
<td>TSO/third party (competitively appointed transmission owner)</td>
<td>TSO</td>
</tr>
<tr>
<td>C</td>
<td>Tenders to third parties (competitively appointed transmission owners)</td>
<td>Third parties</td>
<td>Third parties</td>
<td>TSO</td>
</tr>
</tbody>
</table>

Model A resembles the current practice whereby the TSO owns all transmission assets and is responsible for their construction, economic utilization, maintenance and system operation. Under model B the OWF developer constructs the transmission assets and after commissioning transfers the assets, and thus the economic ownership, to the TSO or another third party which could be appointed as transmission owner through competitive tenders. The system operation remains with the TSO. It is noted that the asset maintenance could be subcontracted back to the OWF developer. This model has similarities with the OFTO, Generator Build approach in the UK. Under model C the transmission asset connecting Denmark and Poland could be tendered directly to third parties who would be responsible for the construction, the ownership and the repair and maintenance of the asset. The third parties have to be licensed as transmission owners under EU Directive 2019/944, art. 40 [36]. In particular, the Directive states that each EU transmission system operator shall be responsible for:

(a) ensuring the long-term ability of the system to meet reasonable demands for the transmission of electricity, operating, maintaining and developing under economic conditions secure, reliable and efficient transmission system with due regard to the environment, in close cooperation with neighbouring transmission system operators and distribution system operators;

(f) ensuring non-discrimination as between system users or classes of system users, particularly in favour of its related undertakings;

Then, this responsibility can be transferred to others (quote from the Directive):

Member States may provide that one or several responsibilities listed in paragraph 1 of this Article be assigned to a transmission system operator other than the one which owns the transmission system to which
the responsibilities concerned would otherwise be applicable. The transmission system operator to which the tasks are assigned shall be certified under the ownership unbundling, the independent system operator or the independent transmission system operator model, and fulfil the requirements provided for in Article 43, but shall not be required to own the transmission system it is responsible for.

Each approach was assessed against a set of criteria related to the net economic benefits i.e. their ability to deliver solutions at least cost and maximum benefit for the society. The views of some key project stakeholders were also sought. The evaluation of the ownership models is a qualitative analysis based on the main assumption that an adequate legislative framework for the hybrid project is in place. In particular the following assumptions were made for the comparison of the different approaches:

- All models are feasible provided that they are appropriately regulated such that transmission owners receive commensurate remuneration for their services and there is clarity on their liabilities.
- A regulated income for all models; it is assumed that the investors’ remuneration is regulated.
- Security of supply for all models; the security of supply (n-1 criteria for the onshore grid) should be guaranteed regardless of the owner of the grid.
- Low entry barriers for participation in the market in a competitive environment; it is assumed that in those cases where third-party asset ownership is allowed, there is a sufficient number of interested parties in the market and they also have the financing and operating capabilities that are required for the construction, operation and ownership of the transmission assets.

In order to perform an objective and consistent evaluation of the investigated ownership models the following assessment criteria has been defined:

- **Integration** – how easy would it be to achieve a high onshore and offshore grid integration & high integration of OWF and offshore grid:
  - Onshore-offshore grid integration includes the onshore grid, offshore HVDC cable and the Hub on Bornholm.
  - OWF-offshore grid integration includes the OWF, the OWF connector, the offshore HVDC cable and the Hub on Bornholm.
- **Learning rate** – given that in all approaches there is a learning curve in constructing the grid, the criterion needs to assess the extent to which the approach allows share of the knowledge that has been gained from earlier projects with other project developers.
- **Regulatory complexity** – does the proposed approach apply a disproportionate regulatory burden
- **Competition for grid development and ownership** – given that all approaches will involve competitive tenders for construction contracts, the criterion needs to assess the extent to which the model facilitates relatively more competition to the benefit of the consumers (e.g. by bringing the costs down).

It is concluded that each ownership model has strengths and weaknesses and there is no consistent preference across stakeholders. Which model to apply is ultimately a political decision and should be taken on the basis of a forward-looking electricity strategy driven by regional energy needs.

### 4.9 FINANCING OPTIONS

In order to further de-risk the Bornholm project, it is possible to apply for financial assistance from the EU. If awarded with a status of a Project of Common Interest (PCI) the hybrid asset connecting Bornholm energy hub would be eligible for funding from the Connecting Europe Facility (CEF), a key EU funding instrument for targeted infrastructure investment at European level. This funding may be in the form of grants, (low-cost) finance or

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6 Although the CEF is connected to the Horizon 2020 programme and as such is expected to end in the coming year. It is also in the EU Budget (yet to be approved) to continue albeit, there may be some changes to the terms and conditions.
investment credits, or a combination of these. In addition to grants, the CEF offers financial support to projects through innovative financial instruments such as guarantees and project bonds (see Table 56 Bornholm energy hub. Financing options.). These instruments create significant leverage in their use of EU budget and act to attract further funding from the private sector. The use of financial instruments under the CEF encompasses the CEF debt instrument and the CEF equity instrument.

Transmission projects are selected as PCIs based on five criteria. They must:

- have a significant impact on at least two EU countries
- enhance market integration and contribute to the integration of EU countries’ networks
- increase competition on energy markets by offering alternatives to consumers
- enhance security of supply
- contribute to the EU's energy and climate goals.

In the TYNDP 2018, an interconnector is already planned between Denmark and Poland. This project represents a "modification" of this plan. As such, a hybrid asset connecting Bornholm island should/could be quickly granted the status of PCI and could become eligible for EU funding (esp. CEF funding) because:

- Contributes to two priority electricity corridors: Northern Seas offshore Grid (NSOG) & Baltic Energy Market Interconnection Plan in electricity ('BEMIP Electricity').
- Has a significant cross-border impact on two EU MS, DK & PL (potentially GE and SE)
  - increases the cross-border grid transfer capacity between DK & PL contributing to market integration, competition and system stability
  - increases the integration of offshore wind into the grid and its transmission to consumption centres in DK and PL contributing to sustainability
- Demonstrates first time application of HVDC Circuit Breaker (CB) technology and HVDC grid protection in Europe contributing to security of supply, through interoperability, DC connections and secure and reliable system operation.
- Reduces the risk for future hybrid projects/artificial energy islands by applying HVDC conversion on an existing island.
- Addresses technical, legal and regulatory issues in a single hybrid project paving the way for meshed grids/islands.

Table 56 Bornholm energy hub. Financing options. below summarizes main characteristics of different EU instruments that could be applicable to fund the hybrid part of Bornholm project.

<table>
<thead>
<tr>
<th>Funding programme</th>
<th>Eligible projects</th>
<th>Funding period</th>
<th>Total budget available</th>
<th>Types of financing</th>
<th>Selection criteria</th>
</tr>
</thead>
</table>

Table 56 Bornholm energy hub. Financing options.
Next to financing of the cable infrastructure, there are also some options under development for financing of the offshore wind farms in this project. First, it could become possible to apply for funding to finance cross-border renewable energy generation via the CEF. The European Commission proposed to renew the CEF instrument, and in the period 2021-2027, up to EUR 8.7 bln will be dedicated to finance energy projects (including energy infrastructure). Out of this amount, up to 10% is proposed to be reserved for cross-border projects in the field of renewable energy generation. However, this proposal has not been adopted yet.
Another financing instrument currently under development is an EU-wide fund for renewable energy based on the Governance of the Energy Union Regulation. This fund, to which Member-States can contribute voluntarily, would be available for renewable energy projects throughout the EU. The exact conditions are not yet known (as there is currently a public consultation ongoing on this topic). This fund would be based on tenders for renewable energy, but it is currently not yet known whether these tenders would be technology-neutral (which would mean that offshore wind energy, which is currently more expensive than onshore wind and solar) would not be able to profit, or whether technology-specific tenders for offshore wind would be organised.

It must be noted that both types of financing are currently still under development and possible subject to many conditions. Thus, the most direct way to finance the OWFs is when the Member-States in question (DK and possible PL) organise a tender for the support of the OWFs.

**4.10 CONCLUSION**

PROMOTioN analysed the proposal to develop an energy hub on the island of Bornholm connecting between 3 to 5 GW of offshore wind via DC cables to Zealand, Denmark (DK) and Poland (PL), and potentially Sweden and Germany in later phases. This idea was supported by the Danish government and proposed as part of the Danish Climate Action Plan in May 2020.

Bornholm being a natural island offers an onshore setting to develop and test DC circuit breakers and a real-life HVDC multi-terminal hub for interconnection of hybrid assets consisting two HVDC links to Poland and Zealand, Denmark and several connected offshore wind farms. Future HVDC links to e.g. Germany could be directly linked to a HVDC multiterminal on Bornholm island.

From the technical studies that PROMOTioN has performed a number of recommendations can be made with regard to how the hub could be dimensioned, what are the protection system options, and what are the consequences of increasing the maximum allowed loss of infeed in DK2. Having analysed several scenarios of interconnection capacities and voltages, it is concluded that for most of the scenarios, rigid bipolar topology rated 320 kV with mutualized metallic return is the best architecture. This is essentially a consequence of the quite low value of the maximum allowed Lol that excludes the symmetric monopolar solution or higher values of voltage. This topology is the most universal from the point of view of minimal CAPEX, as it remains relatively cheap regardless of what is the capacity of transmission corridors to DK2 and PL. If, however, the actual decision would be to build 1500 MW corridors in both directions and provided that Lol can be increased at least up to 750 MW, then a 400 kV bipole with metallic return is observed as the best solution overall. PROMOTioN has explored potential economic advantages of implementing the hub with DC technology instead of AC. From the point of view of extending the hub in the future towards Sweden and Germany, it turns out that the additional CAPEX in AC hub option is higher than the DC hub option. This is due to the fact that additional converter power capacity in Bornholm node is required in AC hub option. The difference between AC and DC topologies increases with the growth of capacity towards Sweden and Germany. Depending the size of interconnection corridor between Denmark and Poland, DC hub also has lower losses and higher availability as compared to AC (the higher are interconnection flows, the more advantageous DC hub is).

PROMOTioN has also supported the Bornholm energy hub project with the regulatory and legal aspects and modelling impacts of possible bidding zone arrangements. Since the legal status of the hybrid asset being neither an interconnector nor a generation transmission asset is uncertain, PROMOTioN in Work Package 7 (D12.3 Chapter 4.3) recommends the legal classification of hybrid assets. A definition of a separate asset class would ease the development of an enabling framework to support the regulatory challenges, not least with regard to capacity allocation and bidding zone arrangements, which have been encountered when studying hybrid assets.

Bidding zone arrangements have substantial impact on the business case for transmission asset owners who claim congestion rent, and for OWFs as energy producers and sellers, and are potentially complex for hybrid-
connected offshore wind. Bidding zones should be defined in such a way that there is no network congestion within a zone. PROMOTioN recommends introducing small offshore bidding zones to ensure efficiency in dispatch and system operation of a meshed offshore grid (see D12.4 Chapter 4.5). If small offshore bidding zones are introduced, OWFs will receive a smaller share of the proceeds.

Three possible ownership models were presented and assessed against their ability to deliver cost efficiently the Bornholm hybrid project. The views of certain project stakeholders were sought. All models were considered feasible provided that they were appropriately regulated such that transmission owners received commensurate remuneration for their services and there is clarity on their liabilities.

Bornholm can serve as a testbed not only for developing innovative HVDC technology but also the appropriate regulatory and market model for the future Meshed Offshore Grid. The project would thus qualify for several funding opportunities targeted at technically innovative projects with significant cross-border impact on EU Member States; in particular CEF financing could be an applicable option to further de-risk the project and allow for its realization by providing monetary support to the involved TSOs/project promoters. This could support the timely development of a project which brings benefits to the Baltic region and important experience and learnings for the future offshore hybrid grid.
5 A MULTI-TERMINAL HVDC DEMONSTRATION GRID: A COST-EFFECTIVE OPTION

5.1 INTRODUCTION

Development of an HVDC grid in North-Sea has been a heavily discussed and researched idea. There have been many studies to explore its feasibility from technological, economic and regulatory point of views [37], [38], [39]. These discussions started with the beginning of this century, but till date there is no such grid. In fact despite a general agreement about large benefits of an HVDC grid in North-Sea, there is no approved project to construct one. In other words, there has already been a lot of research on the conceptual feasibility of such a grid, but actual realization is yet to come. The situation looks like there are benefits but no one has seen them harnessed. The cost involved is very high for any single entity of electricity sector and the fear of loss due to uncertainty is also there. In such a situation it becomes very challenging to demonstrate the real worth of the idea i.e. an HVDC grid. Despite all the positive talks around the idea, it cannot be realized until someone or a group come forward to invest in it.

This part of the PROMOTioN project aims to address this particular aspect. It explores the financial viability of an HVDC grid in the North-Sea. The idea is to calculate whether an HVDC grid in this region is a cost-effective investment or not. This project looks at the problem from an investment point of view. At this point, the authors would like to make it very clear that this study is not as detailed as other short-term projects. This is mainly because of the difference in objective and therefore workforce assignment. The objective of other short-term projects is to provide recommendations which are ready to execute in order to realise an HVDC grid, by extension of existing HVDC projects. Whereas, this study is to make a high-level assessment of the cost effectiveness and nature of the investment in a completely new HVDC grid. The assumptions and their impact on the outcomes of the study have been covered extensively in the section titled as Discussions. Thus, the positive outcome of this study implies that the investment is cost-effective with great potential and therefore, must be explored in further detailed project.

A financial schematic is proposed for decision making about the investment in a DC grid, as shown in Figure 100. On the left, it shows the total expenses associated with a transmission investment project. The total cost consists of capital expenditure (investment cost), operation expenditure and the financial costs which are related to risk (uncertainty). On the right, the benefits are represented. The benefits are divided into assured benefits, expected benefits and potential benefits. Since looking into the future always have a degree of uncertainty, this study performs the calculations under different scenarios of future. Here the authors rely on the scenarios provided in TYNDP 2018 by ENTSO-E and ENTSO-G [40]. The assured benefits are the least amount of benefits among all the scenarios considered in the study. In other words, under all the possible scenarios considered in the study, this much benefits are assured. The potential benefits are benefits of best-case scenario i.e. the scenario giving highest amount of the benefits. But generally something in between these two which can be expected and that is represented as expected benefits. When potential benefits are less than the total cost, the investors may not be encouraged to invest in the project. If the assured benefits are greater than the total cost, there is a certain investment opportunity. When the assured benefits are less than the total cost and expected benefits are more than the total cost, a risk is involved. Before making this investment, there should be an assessment to handle this risk. Given the uncertainty involved in future energy scenarios, most investment cases fall in this category.

Further we discuss the methodology adopted to calculate the benefits. Based on these benefits a cost-benefit analysis is performed. Then the results are presented. This report also covers a discussion about solutions to the
regulatory hurdles in the operation of such a grid. Finally, the report is concluded with remarks based on the findings of the study.

### 5.2 METHODOLOGY

The main approach used in this study for the cost-benefit analysis is price based. When two zones (here countries) having different electricity prices, are connected using an interconnector, their prices change. Price goes up in exporting country while it goes down in importing country. Figure 101 (source: [41]) describes this phenomenon. The y-axis represents price \( p \) and the x-axis represents quantity \( q \) of power generated. The line \( S \) represents a linear model of relationship between \( p \) and \( q \), and \( D \) stands for power demand. When there is no flow over the link connecting importing country A and exporting country B, \( p-q \) curves settles at price \( A_p^0 \) and \( B_p^0 \). After establishing a flow over the link, the exporting area B produces additional power which results in increasing price from \( B_p^0 \) to \( B_p^1 \). On the other hand, importing area gives priority to cheap imported power which results in decreasing price from \( A_p^0 \) to \( A_p^1 \).

This change in prices, also changes the surplus of consumers (pink area) and producers (light blue area). The final difference in the prices multiplied by the power flow over the interconnector is considered as the income \( \epsilon \) of the interconnector. Thus, the total monetary benefit of an interconnector is distributed among the consumers, prosumers and interconnector owners (and/or operators).

This study assumes that there is no price change even after the construction of the interconnector and power flow over that. It can be interpreted as slope \( S=0 \) in Figure 101. It means the exporting country can produce the additional amount of power at the same marginal cost and, the importing country doesn’t reduce its prices even when there is an import of cheaper power. For the importing country, it is as good as replacing some portion of generation (having high cost) by power purchased at lower prices. This assumption helps in capturing the total benefits of interconnector without calculating the changes in producer and consumer surplus. Since the price reduction in the importing country, is also a benefit of the interconnector. But this assumption on the export side, brings a bit of overestimation. Since the additional power produced by the exporting country comes at higher cost. Thus, the price difference between the countries, multiplied with the power flow over the interconnector gives total...
global welfare of the link. Calculating this value for entire year gives the annual global welfare by the interconnector. With the assumption of no change in the prices, it is also equal to the annual income of the interconnector. Therefore, it is taken as the annual benefit of the link.

Figure 101: Price variation due to interconnections (source: [41]).

This study relies on day-ahead market prices for this purpose as shown in Figure 102. It shows the hourly day ahead market prices of the UK (blue) and Denmark (orange) for the year 2018 [42], and the price difference (green). Integration of absolute values of price difference i.e. green colored plot, over the entire year, gives the total annual benefits by a link of unit (MW) capacity. This amount is 194,589 €/Year for a link between UK and Denmark, with the prices of year 2018. Mathematically it can be represented as:

\[
\text{Annual Price difference} = \sum_{i=1}^{8760} |p_{Ai} - p_{Bi}| \left( \frac{\text{MW}}{\text{year}} \right)
\]
Now we need to decide about the topology of the grid. In order to take this decision, the price differences for all the potential countries are calculated as per the proposed methodology and the values are listed in Table 57. The numbers in this table are sum of price differences (integrated over year 2018) between the countries in respective row and column. Low values of the elements imply that the pairs have similar prices. We can see that

- UK has highest price difference with rest of countries.
- DK-NO-SE have similar price (highlighted in orange).
- BE-NL also have similar prices (highlighted in purple).
- DE has quarterly average prices for first quarter of 2018, closer to SE than BE, but hourly price difference aggregated over the entire year (also termed as annual price difference) is almost same (in light green highlight)

### Table 57: Annual price difference for year 2018 (€/MW/year)

<table>
<thead>
<tr>
<th></th>
<th>UK</th>
<th>DK</th>
<th>SE</th>
<th>NO</th>
<th>DE</th>
<th>BE</th>
<th>NL</th>
<th>FR</th>
</tr>
</thead>
<tbody>
<tr>
<td>UK</td>
<td>194,589</td>
<td>190,266</td>
<td>198,628</td>
<td>190,266</td>
<td>133,607</td>
<td>120,437</td>
<td>145,475</td>
<td></td>
</tr>
<tr>
<td>DK</td>
<td>194,589</td>
<td>38,507</td>
<td>43,862</td>
<td>35,714</td>
<td>113,547</td>
<td>83,300</td>
<td>82,565</td>
<td></td>
</tr>
</tbody>
</table>
It must be observed that the quarterly average prices of BE and NL, for first quarter of 2018, are exactly same but their hourly price difference aggregated over the entire year (also termed as annual price difference) is more than that of DK and DE. Thus, aggregated hourly price differences give better insight into the price patterns of different countries, which further implies the utility of interconnecting links. Moreover, it should also be kept in mind that, this table is corresponding to only one year that is 2018. It is quite possible that these patterns are different in other years. Therefore, the topology decided solely on the basis this cannot be optimal. But again, this exercise is not about finding the best topology. It is to take a promising topology in the North-Sea and find out it's cost effectiveness. Therefore, it is reasonable to make a triangular HVDC grid in following manner:

- One terminal in UK,
- Another terminal in Denmark, Norway or Sweden and,
- Third terminal in Germany.

Here, we have selected Denmark from the second group since length of subsea cable constitutes the most significant part of capital investment. Germany is selected as third terminal due to its large system size and least prices. Thus, this study proposes a topology as shown in Figure 103. This is an HVDC grid that means meshed on DC side. The exact locations in the specific countries are Lincolnshire in UK, Jutland in Denmark and Wilhelmshaven in Germany. These locations have been selected on the basis of two already proposed interconnector projects Viking Link and NeuConnect. Here, each link has been considered to have a capacity of 2000 MW. At this point, it is very important to notice that the exact locations of the grid terminals and the capacities of the links have not been selected on the basis of any detailed technoeconomic analysis. Therefore, it is open to more detailed optimal selection. Further we will see that the proposed topology is good enough for the purpose of this study.
5.4 COST-BENEFIT ANALYSIS

Here, the cost is calculated on the basis of PROMOTioN project cost data [43]. In this, investment cost or capital expenditure (CapEx) consists of terminal cost and cable whereas annual operational cost is taken as a fixed percentage total capital investment. While benefits are calculated using the proposed methodology. It is important to note that a lot of benefits of DC grid have been listed in literature such as ancillary services, renewable integration, reliability and security of supply etc. [44]. But this study considers only the benefits of exchanging energy since it is the most significant one and easy to calculate. Others are difficult to assess (assign some monetary value) and have less effect on the outcome of this study. Therefore, it would be prudent to incorporate most of them in a more detailed study and more optimized grid design.

5.4.1 INVESTMENT AND OPERATIONAL COST

Following Table 58 shows the investment cost of each individual link which is aggregated to get the total investment cost of the project. This calculation has following salient points:

- Length of the link is determined by calculating the distance between coordinates using a tool this link (https://www.movable-type.co.uk/scripts/latlong.html).
- Converter Station type: 2000MW bipolar VSC MMC
- Cable type: 10/90 submarine cable.

<table>
<thead>
<tr>
<th>Length (km)</th>
<th>Terminal Cost M€/stn</th>
<th>Submarine cable cost M€/km</th>
<th>Submarine cable cost M€</th>
<th>Total CapEx M€</th>
</tr>
</thead>
<tbody>
<tr>
<td>UK-DK</td>
<td>760</td>
<td>385</td>
<td>770</td>
<td>2708</td>
</tr>
<tr>
<td>UK-DE</td>
<td>550</td>
<td>385</td>
<td>770</td>
<td>2172.5</td>
</tr>
</tbody>
</table>

Table 58: Investment cost for the grid
Since many uncertainties are involved in this calculation, we add an uncertainty factor of 10% in the investment cost. Thus, investment cost i.e. CapEx is $6288 \times 1.1 = 6919$ M€. Now, as per PROMOTioN project cost data [43], an annual operation cost is calculated as 2.5% of the investment cost i.e. OpEx=$6919 \times 0.025 = 173$ M€/yr.

5.4.2 ANNUAL BENEFITS (BASED ON 2018 DATA)

This subsection demonstrates the approach to calculation annual benefits for the proposed grid. Annual price differential for individual links are aggregated to get the benefits of the grid, as shown in Table 59. Here it is assumed that each link in the grid is utilized fully over the entire year, provided that there is a price difference between the zones. This assumption implies that sufficient generation capacity exists in the exporting region and there is no internal (or local) congestion in all the regions.

<table>
<thead>
<tr>
<th></th>
<th>Aggregated Price Difference €/MW/Yr</th>
<th>Capacity (MW)</th>
<th>Total Annual Benefit (M€/Yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>UK-DK</td>
<td>194,589</td>
<td>2000</td>
<td>389</td>
</tr>
<tr>
<td>UK-DE</td>
<td>190,265</td>
<td>2000</td>
<td>381</td>
</tr>
<tr>
<td>DE-DK</td>
<td>35,714</td>
<td>2000</td>
<td>71</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>420,568</strong></td>
<td></td>
<td><strong>841</strong></td>
</tr>
</tbody>
</table>

The above benefits are based on day-ahead prices for year 2018. But it is important to consider some future scenarios, in order assess the benefits over the life of the project. For this purpose, the study relies on the scenarios provided by ENTSO-E under TYNDP 2018 [40]. However, this data set provides only the annual average prices, not the day-ahead hourly prices. To overcome this challenge, an assumption is made. It is assumed that the price pattern or price variability remains the same as in 2018. Thus, the hourly prices are calculated as:

$$p_{i,\text{scenario}} = p_{i,2018} \times \left(\frac{p_{\text{avg,scenario}}}{p_{\text{avg,2018}}}\right)$$

Where $p_{i,\text{scenario}}$ and $p_{i,2018}$ are $i^{th}$ hour prices in the scenario year and 2018 respectively while $p_{\text{avg,scenario}}$ and $p_{\text{avg,2018}}$ are the annual average price in the scenario year and 2018 respectively.

Benefits for the scenario years are also calculated in the same manner as for the year 2018. These values are presented in the Table 60. Where second column has the average prices for the scenarios in first columns. These values are converted into hourly prices for the scenarios year, using the above equation.

5.4.3 PAYBACK PERIOD UNDER DIFFERENT SCENARIOS UP TO 2045
The present value of the future income (in terms of benefits) is calculated using the following formula:

\[
\text{Present Value of Net Benefits} = \sum_{i=1}^{n} \frac{\text{Net Annual Benefits}}{(1 + r)^i}
\]

Where \( r \) is the annual interest rate and \( n \) is the number of years with benefits, in other words lifetime of the project. Here the term ‘net annual benefits’ means the annual benefits after subtraction of annual operational cost from total annual benefits.

The payback period refers to the amount of time it takes to recover the cost of an investment [45]. As the value of cash should be measured at same point of time, payback period is the value of \( n \) for which present value net of benefits is equal to the investment cost or the net cash flow in the project is equal to zero. This value is calculated for different price scenarios and different interest rates, as presented in Table 60. Here net annual benefit is calculated by subtracting operation cost from the total annual benefits.

Here, total three scenarios are considered. Distributed generation (DG) and sustainable transition (ST) scenarios have data for years 2030 and 2040, whereas 2030EU (European union commission) converges to Global Climate Action (GCA) in year 2040. All the scenarios have been developed with aim to reduce emission by 80 to 95%, which is line with EU targets for 2050. ST scenario considers achieving the goal through national regulations, emission trading schemes and subsidies. It tries to maximize the use of existing infrastructure. Whereas DG scenarios is prosumer centric. It takes the path of harnessing small scale but widespread energy resources. 2030EU (or EURCO30) models the achievement of 2030 climate and energy targets, but along with energy efficiency target of 30%. GCA aims for global decarbonization a full speed. It models the development of large-scale renewables in both electricity and gas. Further details about the scenarios presented here, can be found in TYNDP2018 scenario data by ENTSO-E [40].

Lifetime of the project is considered as 25 years which is much less than typical lifetime of transmission lines (i.e. around 40 years). This assumption does not have any impact on the payback period but adds to underestimation of benefits over entire life of the project. Another important point is, for each scenario, the 25 years of lifetime are divided in three parts. As shown in Error! Reference source not found., for the first 5 years, every scenario is considered to have prices (and therefore benefits) same as year 2018 data. Next 10 years are considered to have their corresponding 2030 values and final 10 years as 2040 data. The 25 years of lifetime can be mapped from 2021 to 2045. That means, the first 5 years corresponds to 2021 to 2025, next 10 years as 2026 to 2035 and the last 10 years as 2036 to 2045.
Table 60: Payback time under different scenarios and interest rates

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Avg Prices DE – DK – UK (€/MWh)</th>
<th>Total Annual Benefit (M€/Yr)</th>
<th>Net Annual Benefit (OpEx=173 M€/Yr)</th>
<th>Payback Period (Yrs) with interest rate of</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>5%</td>
</tr>
<tr>
<td>2018 data</td>
<td>44.47 44.05 66.05</td>
<td>841</td>
<td>668</td>
<td>17.71</td>
</tr>
<tr>
<td>2030EU</td>
<td>68.36 78.48 68.65</td>
<td>889.36</td>
<td>716.36</td>
<td>19.61</td>
</tr>
<tr>
<td>2040GCA</td>
<td>50.61 50.46 53.14</td>
<td>510.56</td>
<td>337.56</td>
<td>23.45</td>
</tr>
<tr>
<td>2030ST</td>
<td>83.60 83.77 82.58</td>
<td>853.44</td>
<td>680.44</td>
<td>19.61</td>
</tr>
<tr>
<td>2040ST</td>
<td>45.17 46.03 42.06</td>
<td>492.66</td>
<td>319.66</td>
<td>23.45</td>
</tr>
<tr>
<td>2040DG</td>
<td>65.30 66.79 64.95</td>
<td>684.79</td>
<td>511.79</td>
<td>17.71</td>
</tr>
</tbody>
</table>

We can see that the payback period varies significantly with the scenario and the interest rate. This in turn has an impact on the nature of the possible investment. Following points can be observed for this table:

- Most of the scenarios give a payback period around 20 years for 5% interest rate while it is around 10 years for 0.5%, and 0% interest rates.
- That means the payback period is very high for any private entity in the market but not too much for a government body. Private investors are more interested in more profit over short time duration while governmental organizations aim for maximizing social welfare.

Annual cash flow for the above data is presented in Figure 105. Here we can see the variations of payback period, or the time needed to reach break-even point, when net cash inflow become zero. In EU&GCA scenario and ST scenario benefits with 2030 data are high, therefore, investment is returned rather quickly in comparison to DG...
scenario. But their benefits decrease with 2040 data, whereas it is sustained for DG scenario. Therefore, benefits over the complete life cycle of the project are not significantly different. It can be observed more clearly in Figure 106.

![Cash flow diagram with annual payments (Interest Rate=0.5%)](image1)

![Cash flow diagram with annual payments (Interest Rate=5%)](image2)

Figure 105: Net cash flow over the life time the project
5.4.4 RETURN OVER COMPLETE LIFETIME

Benefits of the project over the complete life cycle are presented in Figure 106. As mentioned earlier, project life is considered to be 25 years and lifetime benefits are calculated for different scenarios and interest rates. Left most three columns are the cost of investment including capital expenditure and an uncertainty factor of 10%. Whereas the all other bars with r varying from 0 to 5%, are the net benefits over projects lifetime. As described earlier, net benefits are the benefits after subtracting operational cost from the total benefits. The most significant observation is net return is positive in all the worst-case scenario (least return i.e. DG wit 5% interest rate). That means project is not going to make net loss in any of the scenarios discussed here. Another important observation is variation in amount of return with variation of interest rate. The returns are very high for institutional investment which usually have interest rates around 0.5 %, whereas it is very less and less motivating for private investor usually having higher interest rates.

At this junction, it is very insightful to revisit the Figure 100. It was considered that there might be some loss in worst case scenarios. In case of the possibility of a bearable loss, a leap of faith (of course, with risk mitigation arrangements) could have been thought, in order to implement and demonstrate the one of the most discussed technology for electrical industry in Europe. But the future does not look so uncertain with the outcomes of this study. It shows that even in worst case there would be no loss. This finding is expected to give more confidence to the authorities concerned with such a grid in the North Sea. Of course, there are some assumptions in the study which contributes to overestimation and underestimation. These are discussed later in detail.
5.4.5 DEMONSTRATING VARIATIONS IN THE CAPACITY OF A LINK

The impact of link capacities on the payback period is analyzed here. The capacity of Denmark-Germany link is changed from 2000 MW to 1000 MW, as shown in Figure 107. The investment cost, annual income and payback periods for this configuration is present in Table 61, Table 62 and Table 63. We can see that investment cost for the link does not reduce by half since the cost of technologies differ. It can be observed from table 5, that per km cost of a 2000 MW and a 1000 MW capacity submarine cables are 2550 k€ and 2050 k€ respectively.

Table 61: Investment cost for the grid with DK-DE link capacity variation

<table>
<thead>
<tr>
<th></th>
<th>Length (km)</th>
<th>Terminal Cost</th>
<th>Submarine cable cost</th>
<th>Total CapEx</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>M€/stn</td>
<td>M€</td>
<td>k€/km</td>
</tr>
<tr>
<td>UK- DK</td>
<td>760</td>
<td>385</td>
<td>770</td>
<td>2550</td>
</tr>
<tr>
<td>UK-DE</td>
<td>550</td>
<td>385</td>
<td>770</td>
<td>2550</td>
</tr>
<tr>
<td>DE-DK</td>
<td>250</td>
<td>220</td>
<td>440</td>
<td>2050</td>
</tr>
<tr>
<td>Total</td>
<td>1980</td>
<td>1980</td>
<td>3853</td>
<td>5833</td>
</tr>
</tbody>
</table>

Table 62: Annual benefits with 2018 data for the grid with DK-DE link capacity variation

<table>
<thead>
<tr>
<th></th>
<th>Aggregated Price_diff €/MW/Yr</th>
<th>2018 Capacity (MW)</th>
<th>Total Annual income (M€/Yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>UK- DK</td>
<td>194,589.07</td>
<td>2000</td>
<td>389</td>
</tr>
</tbody>
</table>
### Table 63: Comparison of payback period

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Net annual benefits</th>
<th>Payback Period (Yrs) with interest rate of</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>0.5%</td>
</tr>
<tr>
<td>2018 data</td>
<td>645</td>
<td></td>
</tr>
<tr>
<td>2030EU</td>
<td>614.32</td>
<td>10.53</td>
</tr>
<tr>
<td>2040GCA</td>
<td>308.68</td>
<td>12.47</td>
</tr>
<tr>
<td>2030ST</td>
<td>622.64</td>
<td>10.53</td>
</tr>
<tr>
<td>2040ST</td>
<td>291.15</td>
<td>12.47</td>
</tr>
<tr>
<td>2040DG</td>
<td>463.54</td>
<td></td>
</tr>
</tbody>
</table>

It can also be observed that the payback period corresponding to this configuration is reduced from 10.66 years to 10.53 years for ST scenario and, from 12.62 to 12.47 for DG scenario, while it increases from 10.37 to 10.60 for EU&GCA scenario, with interest rate of 0.5%. Thus, there is a scope for optimizing the topology under different scenarios. But the most important point to note here is, this change not significant to change the planning of financing the investment.

### 5.5 DISCUSSION

It is observed that a DC grid in North Sea is financially viable. It returns its investment cost by having a significant amount of benefits; however, this happens over a long-time horizon. As shown in the previous section, the private investment is less likely to happen. Therefore, government investment looks to be a way forward. The EU interest rate for different countries is found to be around 0.5% [46]. For this interest rate, payback period is in-between 10 and 13 years for all the three scenarios. This period is much below the average lifetime of engineering infrastructure i.e. 30 year. That means, the project is going to generate profit under all the scenarios.

Before closing the report with concluding remarks, it is important to summarize the major assumptions or simplifications made during the course of this study.
5.5.1 ASSUMPTIONS:

- Enough demand, supply and internal network capacity are available to utilize the full capacity of the links: Any of these limitations can reduce the utilization which in turn reduce the revenue.
- No change in prices even after installing the link: Since the price change is the result of the link placement, this assumption helps in capturing the benefits in a simple manner. It avoids the necessity to measure the changes in consumer and producer surplus.
- Uncertainty on investment is taken 10%.
- Price variability in scenario years is taken to be same as year 2018.
- Lifetime of the project is taken as 25 years.

5.5.2 OVERESTIMATIONS:

Here is a small list of some possible over-estimations in the study:

- When grid is not utilized fully, due to some other constraints, its revenue will reduce.
- Network reinforcement cost has not been in respective countries. It might go beyond the 10% uncertainty factor of investment.
- The assumption of keeping the prices unchanged, might result in some overestimation as the additional imported power might come at an increased cost.

5.5.3 UNDERESTIMATIONS:

Some major factors of potential underestimations are as follows:

- Investment cost: It is taken to sum of the cost three individual links. A more detailed sensitivity analysis and economy of scale have the potential to reduce it. In other words, cost of the capacity of the converter stations can different (more optimal) than 4000 MW each, and the cost of a 4000 MW station would be less than two time the cost of a 2000 MW station.
- Operational cost: In a grid structure, some power is bypassed at a DC bus without passing through its converters. It avoids extra losses and congestion. Thus, OpEx for the DC grid structure should be less than that of three individual links.
- Price variability: Due to increased renewable penetration prices are expected to be more volatile in 2030 than 2018. Therefore, assuming the price variability same as 2018 might cause a potential underestimation.
- Lifetime: Typical lifetime of engineering infrastructure is taken as 30 years which is around 40 years for electricity transmission networks. But the lifetime considered in this study is 25 years. Therefore, it has the potential of a significant amount of underestimation. The rationale behind taking keeping it 25 years is two-fold. First, calculation of benefits beyond 25 years is highly prone to error, because we have price data scenarios for 2030 and 2040 only, not 2050. The reason is acceptance of this number in other studies for cost-benefit analysis of interconnectors [41].
- Benefits under consideration: This study is based on the price differential benefits only. But a number of other benefits and their assessment methodology are discussed by ENTSO-E in [44]. This study might be an overall underestimation of benefits, when all other direct and indirect benefits considered such as:
  - Reserves/Ancillary Services,
  - RE addition and reduction in CO2 emission,
  - Reliability, stability and Security of supply.

5.6 CONSTRUCTION AND OPERATION

It has been observed that existence of an HVDC grid in the North-Sea is cost effective. Such grid has also been shown to have huge social benefits [44]. But construction and operation of such a grid are the major roadblocks [37]. The large payback period makes it less attractive to private investors. On the other hand, the investment cost is too high for different transmission system operators (TSOs) to come together. Along with that there are operational challenges also, to discourage the TSOs from investing in such a project.
At this stage, the authors of this report propose following approach.

- EU funds the investment in construction and build it as a demo. It may or may not accept co-investment from any of the TSOs or some (enthusiastic) private investors.
- EU becomes the owner of the grid and places it under a central regulation (e.g., ACER) as demonstration project.
- Preferably, a separate entity (company/body) is created for the role of operator. It is also possible that ENTSO-E takes up this job, or alternatively one of the regional coordination centers.
- Once the grid has been demonstrated to be operating smoothly, EU sells it to TSO(s) and/or private entity or entities.

Thus, EU can successfully demonstrate a project of high public values and also get some return on the investment. Even in the worst-case EU does not have any loss, as per the scenarios studied in this report.

5.7 CONCLUSION

This study has shown that an HVDC grid in the North-Sea can be demonstrated without making any loss. Finally, the study can be concluded with following points:

- An HVDC grid in the North-Sea is cost effective. It can pay back its investment even in the worst scenarios, while having the potential of very high returns on the investment.
- Given the very high amount of investment and large payback period, private investor would not be very keen in such an investment. It indicates the investment in such a grid is more likely to come from an institutional investor such as EU or governments of the countries involved.
- If EU takes a lead, it can demonstrate a project which is one the most discussed topic in electrical industry of Europe. Most importantly, EU can make this demonstration without incurring any losses while having potentially high social benefits.
- The benefits would also include remaining technologically in the lead with respect to power system technology, and in particular HVDC
- The demonstration project would lead to job employment, on the short run in Europe for the installation, but in the long run globally.
- A DC grid is an enabler for the future large-scale integration of renewables in Europe and the deployment of far offshore renewables.
6 REFERENCES


### 7 APPENDIX

#### 7.1 WINDCONNECTOR PROJECT

##### 7.1.1 ROCOV MEASUREMENTS

Table 64 - Complete ROCOV measurements for P-G and DMR-G faults

<table>
<thead>
<tr>
<th>FAULT TYPE</th>
<th>FAULT RESISTANCE</th>
<th>LOCATION</th>
<th>DV42P/DT</th>
<th>DV4P/DT</th>
<th>DV42N/DT</th>
<th>DV4N/DT</th>
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<tbody>
<tr>
<td>P-G</td>
<td>0.01</td>
<td>Bus 1</td>
<td>-1567.03</td>
<td>-144.613</td>
<td>-10.4279</td>
<td>-6.1306</td>
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<td>-2.42974</td>
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<td>-4.76241</td>
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<td>0.01</td>
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<td>DMR-G</td>
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<td>Bus 3</td>
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<td>-1.65725</td>
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<td>-1.38792</td>
<td>-2.00507</td>
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</table>
7.2 SOUTHWEST LINK AND HANSA POWER BRIDGE DC CONNECTION

7.2.1 ADDITIONAL DETAILS ON TECHNICAL STUDIES

7.2.1.1 SWITCHING BETWEEN CONDUCTION AND NON-CONDUCTION OF THE DC CONNECTION.

There are several possible methods by which the DC connection can be connected or disconnected. The protection solutions focused on in this report include a large series inductor – primarily applied to limit the rate of rise of DC fault current but also useful to limit the transients experienced when connecting the two point-to-point systems. Given the presence of this large inductor, there is no strict requirement for a complex switching sequence which aims to control the voltage across the DC connection to near zero. If it were possible to perform control mode and control set point changes on-line, the connection sequence could include changing the voltage control modes of the converter stations such that the voltage across the DC connection is controlled to be as small as possible. This control mode would be required in case of no additional inductance in the DC connection (e.g. protection solution with AC CB primary protection and no DCCBs), but is not required for the protection options with DCCBs.

Switching from conduction to non-conduction requires commutation of the current from the DC connection through the converter stations at Hurva. This commutation can either be performed manually (by control set point change, if possible on-line), or can be achieved by operating the DCCB. Ordering the DCCB to trip in this scenario implies some requirement for energy dissipation in the DCCB varistors, however, this energy dissipation requirement is an order of magnitude smaller than that typically dissipated following a DC fault and so would not be expected to be problematic for the installed DCCBs which are rated to isolate a fault and dissipate the associated energy.

Given the designed droop strategy for each of the converter stations (Figure 10), there is no need for control mode switching when changing the state of the DC connection – either from not conducting to conducting, or vice versa. The designed droop settings provide the most flexible anticipated control mode, however, having a single control mode that operates in each of the DC connection states results in a marginal reduction in transmission capacity for one of the systems in case the DC connection is not conducting. For long periods when the DC connection is not used, there would be a small advantage to reverting to the existing droop controls used in the individual point-to-point systems.

Time domain simulation performed has indicated that the transients following connection of disconnection of the DC connection without control mode switching are minimal; the transient would not impact the continuous operation of any of the four converters in the system (two in the SWL and two in the HPB), and the droop control successfully coordinates the required power flow commutation to and from the DC connection.

7.2.1.2 COMMUNICATION REQUIREMENTS AND CONTROL LAYOUT

The control of the overall system, combining the SWL and the HPB, requires minimal low speed communications. Given that power and voltage droops can be chosen so that the power flow is controlled in each of the switching states, there are no rapid set point changes required. In the simplest case, it would be possible to operate the system with no additional control signals, however, it is suggested that it would be more secure to operate with an interlocking signal indicating the availability of the SWL and the HPB, such that the DC connection is only made when the P2P connections are stable and ready for DC connection. This proposed control structure is shown in Figure 108. In case of operation without a DCCB, an additional interlock signal would be of value,
indicating the state of the DC connection (conducting or not conducting), which would allow for faster recovery following a DC fault. The control structure for this case is shown in Figure 109.

![Control Structure Diagram](image)

Figure 108: Possible control structure of SWL-HPB DC connection – DC CB protection. All indicated signals are low speed and could be coordinated around the Hurva substation (i.e. no new signals sent outside of a substation)

![Control Structure Diagram](image)

Figure 109: Required signals for SWL-HPB DC connection without DC CB. All indicated signals are low speed and could be coordinated around the Hurva substation (i.e. no new signals sent outside of a substation)

### 7.2.1.3 BACKUP PROTECTION: IMPACT OF FAILURE OF PRIMARY PROTECTION

Although backup protection is not focused on in this report, some analysis has been performed examining the possible backup protection options. In case of breaker failure, backup protection is provided by the AC circuit breakers at the AC-side of every MMC. The following response to a fault on the HPB, Figure 110, shows that the recovery time for the healthy HVDC system is significantly longer than that observed in the case for which primary protection is provided by the ACCBs. The cause of this is the very large additional inductance which is in the fault current path, which, in the critical case, contributes to the well-known free-wheeling inductive discharge effect following a fault near a half-bridge MMC. It is observed that in the case with a 250 mH inductor (2 ms DCCB) the inductive discharge takes more than 2 s and in the case with a 900 mH inductor (8 ms DCCB) takes more than 8 s. This large delay significantly delays the post-fault recovery of the healthy point-to-point system and means that the single DCCB per pole protection solution is highly unattractive when considering breaker failure.
Because of the shortcomings of the single DCCB per pole configuration, it is interesting to consider the case in which there is a redundant DCCB in the DC connection, Figure 111. It is proposed that the inductor sizing should remain the same as in the previous case Table 2, and that the additional DCCB should not aim to keep the healthy link in continuous operation, but rather to rapidly isolate the fault and allow rapid recovery. Note that the operation of both series DCCBs simultaneously would result in a significant overvoltage on some components (e.g. ~900 kV / 3 pu.) and so is not likely to be acceptable.

In the primary protection case, the protection would perform the same as in the previous case study. In the backup protection case (in case of CB failure) the backup DCCB would operate following a detection delay (5 ms is applied in this case study). Three options for backup protection are considered here providing backup protection for a 2 ms DCCB; another 2 ms DCCB, an 8 ms DCCB, and a 20 ms DCCB (or other possible suitable switchgear).
It is shown that in each of the cases, the healthy point-to-point system (the SWL) blocks and begins its protection and recovery sequence. In each case the backup protection isolates the fault from the healthy point-to-point system and allows recovery in less than 200 ms, as shown in the example, Figure 112. It is concluded that if the inductors are only sized for primary protection, the speed of the backup protection is not significant as long as there is some means of interrupting the DC current.

7.3 BORNHOLM ISLAND – CLEANSTREAM PROJECT

7.3.1 ENERGY SYSTEM MODELLING

7.3.1.1 ASSUMPTIONS AND SYSTEM CHARACTERISTICS

The energy system model used to simulate different scenarios of Bornholm energy hub implementation considered several EU countries considered: NO, DK, FI, DE, NL, SE, UK, PL, BE, FR. Optimization was performed for three years optimized: 2025, 2035, 2045, considering both electricity and heat market, including electric vehicles demand. CO2 Price is assumed to vary between 6 to 120 € (2015) / ton CO2 depending on the country. Finally the total capacity of the wind farm is assumed to be equal 3 GW in all scenarios with the number of full-load hours 4590.

Below is a list of some other assumption which affected the outcomes of modelling:

- Energy system modelled from a socio-economic point of view. Therefore, no taxes or grid tariffs are considered. The socio-economic investment decisions may be very different from business decisions made by market actors.
- We only model the day-ahead market and dispatch, and do not consider balancing and real-time effects.
Model results are sensitive to the inputs, which in this case have a high level of uncertainty. Due to computational time, the investment optimization must be done with aggregated time steps, meaning that the model may not capture all price variability for the investment decision. When the Bornholm hub is included in DK2 bidding zone, the transmission line between DK2 and Bornholm is assumed infinite – leading to potential redistributions not considered in this study. As a result of the modelling, the future energy system becomes highly interconnected and is remarkable by the high level of heat sector electrification which drives up demand for electricity. Exact figures are given in Figure 113.

Figure 113 Bornholm energy hub. Future energy system.

Figure 114 presents the energy mix of each considered country, where it can be seen that wind technology is very competitive.

Figure 114 Bornholm energy hub. Future system energy mix.
All prices decrease somewhat over time. Price of the hub is very close to DK2 price zone. Price in Poland consistently approximately 10-15% higher.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Year</th>
<th>DK2</th>
<th>BHUB1</th>
<th>PL</th>
<th>TOTAL SYSTEM</th>
</tr>
</thead>
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<tr>
<td>1.5/1.5 GW BH own market zone</td>
<td>2025</td>
<td>40.31</td>
<td>40.16</td>
<td>44.77</td>
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<tr>
<td></td>
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<td>37.22</td>
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<td>37.71</td>
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<td></td>
<td>2045</td>
<td>36.36</td>
<td>36.27</td>
<td>42.77</td>
<td>36.92</td>
</tr>
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<td>3.6/0.6 GW BH own market zone</td>
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</tr>
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<td>2045</td>
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<td>36.31</td>
<td>42.85</td>
<td>37.05</td>
</tr>
<tr>
<td>1.5/1.5 GW BH in DK2</td>
<td>2025</td>
<td>40.56</td>
<td>40.56</td>
<td>44.80</td>
<td>40.17</td>
</tr>
<tr>
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<td>2035</td>
<td>37.41</td>
<td>37.41</td>
<td>42.80</td>
<td>37.73</td>
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<td>2035</td>
<td>33.88</td>
<td>33.88</td>
<td>40.27</td>
<td>34.20</td>
</tr>
<tr>
<td>3.6/0.6 GW BH in DK2</td>
<td>2025</td>
<td>40.39</td>
<td>40.39</td>
<td>44.75</td>
<td>40.15</td>
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<td>2045</td>
<td>33.78</td>
<td>33.78</td>
<td>40.20</td>
<td>34.16</td>
</tr>
</tbody>
</table>

* 15BB = 1.5-1.5 GW OFW as Bornholm hub, separate bidding zone; 15BD = 1.5-1.5 GW OFW in DK2 bidding zone; 36BB = 3.6-0.6GW OFW a Bornholm hub, separate bidding zone; 36BD = 1.5-1.5 GW OFW in DK2 bidding zone.
Absolute Delta Market Price from 3.6,0.6 GW to 1.5,1.5GW

Delta 1.5,1.5 - 3.6,0.6 for BH
Delta 1.5,1.5 - 3.6,0.6 for DK2

Absolute Delta Market Price from 3.6,0.6 GW to 1.5,1.5GW

Delta Market Setup: BHUB - DK2

Delta BH - DK2 for 1.5 GW
Delta BH - DK2 for 3.6 GW
Price Duration Curve BHUB1

Curtailment Ratio [% over RES Production]
7.3.2 CHOICE OF THE OPTIMIZED DC HUB CONFIGURATION

7.3.2.1 COST DATA AND ASSUMPTIONS

Cost model for cable and converter are derived from PROMOTioN data collection task. Extrapolation for more voltage and power ratings is applied, see Figure 7-115.

Financial data and assumptions:
- Price energy: 50€/MWh or 100€/MWh used to monetize losses.
- Life time: 30 years
- Discount rate 8%
- CAPEX is equally distributed 2 years before commissioning i.e.
  - Half of 2026 investment costs in 2025 and half in 2026
  - Half of 2028 investment costs in 2027 and half in 2028

Following assumptions are made to compute the EENT:
- All measurement (voltage, current sensors) and control (relays) devices are considered as fully reliable (zero failure rate)
- All related control and protection algorithms are considered as fully reliable (sufficiently redundant control systems and algorithms are supposed)
- The blocking state operation is considered as fully reliable for both half bridge (HB) and full bridge (FB) MMC. Furthermore, as the current limiting state operation is based on control action, it is considered as fully reliable for FB MMC. As a consequence, a zero failure rate is considered for FB MMC
- All passive components (e.g. DC reactor, capacitance, etc.) are considered as fully reliable (zero failure rate)
- Considered non zero failure rate components are:
  - High speed switches (HSS)
  - DC circuit breakers (DCCB)
  - Cables, converters
- A non-bundled cables are considered. So, a degradation modes are possible and loss of the two cables is then due to N-2 contingency (or more than N-2). Similarly, the metallic return failure is considered as independent to the associated cables.
If the DCCBs, DBS or high speed switches protecting a line (see Figure 7-116, left) or a converter (see Figure 7-116, right) are not available, the protected component is disconnected. In Figure 7-116 (left), the line is disconnected if the 2 associated DCCBs or the 2 associated Switches failed. Similarly, in Figure 7-116 (right), the converter is disconnected if the associated DCCB or the 2 associated Switches failed.

The line is disconnected if both DCCB or Switches failed

The converter is disconnected if DCCB failed

Figure 7-116 : Scenario 1b (maximum loss of infeed of 600 MW, rated voltage 320 kV) single line diagram for DC hub at Bornholm node

Data used to compute expected energy not transmitted EENT are summarized in Table 65.

Table 65 Reliability data used to compute EENT

<table>
<thead>
<tr>
<th>Reliability data</th>
<th>Converter</th>
<th>Cables and MR (per 100 km)</th>
<th>DCCBS</th>
<th>HHSs</th>
<th>Busbar</th>
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<tr>
<td>Onshore MTTF(hours)</td>
<td>6257</td>
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<td>16000</td>
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<td>MTTR(hours)</td>
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<td>2304</td>
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<td>Unavailability</td>
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<td>0.00001</td>
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The macroscopic framework methodology used to compute EENT is presented in Figure 7-117. The main idea consists to:
- Estimate the probability of each configuration resulting from a component failure. To do this, Mean Time To Failure MTTF and Mean Time To Repair MTTR are used.
- For each configuration resulting from contingencies and for each operating point (hourly load flow time series) compute a new load flow. Compute EENT which is the difference between the initial hourly load
flow (without contingencies) and the obtained load flow (with contingencies). It should be noticed that the probability of the configuration is multiplied by the calculated EENT.

Ideally, to estimate the part of the protection scheme components on the total EENT, a calculation should be done with and without a protection. However, due to the computational time needed for this, only one simulation (with protection strategy components) is made and the part of the protection strategy on the total EENT is deduced as follow:

- Only a (or several) grid component (cable or converter) failed: The EENT is due to the grid components
- Only a (or several) protection component failed: The EENT is due to the protection scheme implementation
- A least one grid component and one protection component failed: The EENT is due to both protection and grid components. In other word, the responsibility on the resulting EENT is shared between grid components (converter and cables) and protection components (DDCBs and DCRs and high speed switches).
7.3.2.2 RESULTS CONSIDERING ONLY CONVERTER AND CABLE CAPEX

Figure 7.118 Scenario 1a, 600 MW maximum allowed loss of infeed
### PROJECT REPORT

**Figure 7-119** Scenario 2a, 600 MW maximum allowed loss of infeed

<table>
<thead>
<tr>
<th>Year</th>
<th>Poland Hub</th>
<th>bipole 3000 MW</th>
<th>bipole 1000 MW</th>
<th>Metallic return 500 MW</th>
<th>Rigib bipole 600 MW</th>
<th>Rigib bipole 1000 MW</th>
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<tr>
<td>2026</td>
<td>16.97</td>
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<td>2027</td>
<td>16.02</td>
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<td>17.36</td>
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<td>16.02</td>
<td>24.91</td>
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<tr>
<td>2028</td>
<td>16.02</td>
<td>17.55</td>
<td>17.36</td>
<td>24.91</td>
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<td>24.91</td>
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<td>16.02</td>
<td>24.91</td>
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</table>

This project has received funding from the European Union’s Horizon 2020 research and innovation programme under grant agreement No 691714.
Figure 7-120 Scenario 2b, 600 MW maximum allowed loss of infeed

Legend

DK2 3600 MW
Bornholm 3000 MW

Rigid bipole 800 MW
Poland 600 MW
### Scenario 2a, 750 MW maximum allowed loss of infeed

<table>
<thead>
<tr>
<th>Year</th>
<th>Installed Power 2030 (MW)</th>
<th>Loss of Infeed (%)</th>
<th>Bipole 1000 MW</th>
<th>Bipole 600 MW</th>
<th>Bipole 1000 MW</th>
<th>Bipole 600 MW</th>
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</thead>
<tbody>
<tr>
<td>2020</td>
<td>18.49</td>
<td>17.89</td>
<td>17.59</td>
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<td>17.59</td>
</tr>
<tr>
<td>2025</td>
<td>18.49</td>
<td>17.89</td>
<td>17.59</td>
<td>18.49</td>
<td>17.89</td>
<td>17.59</td>
</tr>
<tr>
<td>2030</td>
<td>18.49</td>
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<td>17.59</td>
<td>18.49</td>
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<tr>
<td>2035</td>
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<td>17.89</td>
<td>17.59</td>
<td>18.49</td>
<td>17.89</td>
<td>17.59</td>
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</tbody>
</table>

*Figure 7-121 Scenario 2a, 750 MW maximum allowed loss of infeed*
Table 66 Summary results for 600 MW maximum allowed loss of infeed and all scenarios

<table>
<thead>
<tr>
<th>Scenario</th>
<th>CAPEX [k€/MW]</th>
<th>Total CAPEX [M€]</th>
<th>Configuration</th>
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<tbody>
<tr>
<td>Scenario 1a</td>
<td>284</td>
<td>1706</td>
<td>SMP/320/2000-1000</td>
</tr>
<tr>
<td>Scenario 1b</td>
<td>239</td>
<td>1718</td>
<td>Rigid bipole+Mutual MR/320/2000-1000</td>
</tr>
<tr>
<td>Scenario 1c</td>
<td>295</td>
<td>1768</td>
<td>Rigid bipole+Mutual MR/320/2000-1000</td>
</tr>
</tbody>
</table>

"Chosen solution" (600 MW LoI)
### Table 67 Summary results for 750 MW maximum allowed loss of infeed and all scenarios

<table>
<thead>
<tr>
<th>Scenario</th>
<th>CAPEX [k€/MW]</th>
<th>Total CAPEX [M€]</th>
<th>Configuration</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scenario 1a</td>
<td>229</td>
<td>1374</td>
<td>Rigid bipole+Mutual MR/400/2000-1000</td>
</tr>
<tr>
<td>Scenario 1b</td>
<td>239</td>
<td>1718</td>
<td>Rigid bipole+Mutual MR/320/2000-1000</td>
</tr>
<tr>
<td>Scenario 1c</td>
<td>273</td>
<td>1639</td>
<td>Rigid bipole+Mutual MR/400/2000-1000</td>
</tr>
<tr>
<td>Scenario 2a</td>
<td>290</td>
<td>1913</td>
<td>Rigid bipole+Mutual MR/320/2000-1000</td>
</tr>
<tr>
<td>Scenario 2b</td>
<td>279</td>
<td>1977</td>
<td>Rigid bipole+Mutual MR/320/1950-1000</td>
</tr>
<tr>
<td>Scenario 2c</td>
<td>299</td>
<td>2154</td>
<td>Rigid bipole+Mutual MR/320/2000-1000</td>
</tr>
</tbody>
</table>

### Table 68 Summary results for 900 MW maximum allowed loss of infeed and all scenarios

<table>
<thead>
<tr>
<th>Scenario</th>
<th>CAPEX [k€/MW]</th>
<th>Total CAPEX [M€]</th>
<th>Configuration</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scenario 1a</td>
<td>229</td>
<td>1374</td>
<td>Rigid bipole+Mutual MR/400/2000-1000</td>
</tr>
<tr>
<td>Scenario 1b</td>
<td>239</td>
<td>1718</td>
<td>Rigid bipole+Mutual MR/320/2000-1000</td>
</tr>
<tr>
<td>Scenario 1c</td>
<td>273</td>
<td>1639</td>
<td>Rigid bipole+Mutual MR/400/2000-1000</td>
</tr>
<tr>
<td>Scenario 2a</td>
<td>290</td>
<td>1913</td>
<td>Rigid bipole+Mutual MR/320/2000-1000</td>
</tr>
<tr>
<td>Scenario 2b</td>
<td>279</td>
<td>1977</td>
<td>Rigid bipole+Mutual MR/320/1950-1000</td>
</tr>
<tr>
<td>Scenario 2c</td>
<td>299</td>
<td>2154</td>
<td>Rigid bipole+Mutual MR/320/2000-1000</td>
</tr>
</tbody>
</table>
7.3.2.3 RESULTS CONSIDERING CAPEX AND LOSSES

Assumptions:
Energy price = 50€/MWh
MR = 0.33 * price(HV)
### 600 MW maximum allowed loss of infeed: 1a

#### Table: Projected Power Distribution

<table>
<thead>
<tr>
<th>Location</th>
<th>Installed Power in 2030 (MW)</th>
<th>Loss in 2030 (MW)</th>
<th>Loss in 2050 (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>SMP 500 MW</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SMP 350 MW</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SMP 200 MW</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>DK2 1500 MW</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bornholm 3000 MW</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

#### Diagram: Power Flow Analysis

- **Poland** 1500 MW
- **DK2** 1500 MW
- **Bornholm** 3000 MW

---

**Legend:**
- **2026 Best Potential**
- **2030 Best Potential**

This project has received funding from the European Union’s Horizon 2020 research and innovation programme under grant agreement No 769714.
### 600 MW maximum allowed loss of infeed : 2a

<table>
<thead>
<tr>
<th>Rigid bipolar 1000 MW</th>
<th>Rigid bipolar 500 MW</th>
<th>Hub 320 kv</th>
<th>Rigid bipolar 1000 MW</th>
<th>Rigid bipolar 3000 MW</th>
<th>Bornholm 3000 MW</th>
<th>Hub 320 kv</th>
<th>Poland 600 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>300</td>
<td>300</td>
<td>300</td>
<td>300</td>
<td>300</td>
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<td>300</td>
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<td>300</td>
<td>300</td>
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<td>300</td>
</tr>
</tbody>
</table>

**Table:**

<table>
<thead>
<tr>
<th>Subtransmission power in 2020 (MW)</th>
<th>Max. real power in 2020 (MW)</th>
<th>Max. reactive power in 2020 (Mvar)</th>
<th>Max. real power in 2022 (MW)</th>
<th>Max. reactive power in 2022 (Mvar)</th>
</tr>
</thead>
<tbody>
<tr>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
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<tr>
<td>200</td>
<td>200</td>
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<tr>
<td>600</td>
<td>600</td>
<td>600</td>
<td>600</td>
<td>600</td>
</tr>
</tbody>
</table>

**Diagram:**

[Diagram showing various power configurations and connections]
### Project Report

**600 MW maximum allowed loss of infeed: 2b**

<table>
<thead>
<tr>
<th>Industrial power in 2020 (MW)</th>
<th>Industrial power in 2025 (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1600</td>
<td>1600</td>
</tr>
<tr>
<td>3300</td>
<td>3300</td>
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<tr>
<td>3600</td>
<td>3600</td>
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<tr>
<td>3900</td>
<td>3900</td>
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<tr>
<td>4200</td>
<td>4200</td>
</tr>
<tr>
<td>4500</td>
<td>4500</td>
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<tr>
<td>4800</td>
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<td>5400</td>
<td>5400</td>
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<tr>
<td>5700</td>
<td>5700</td>
</tr>
<tr>
<td>6000</td>
<td>6000</td>
</tr>
</tbody>
</table>

**Legend**

- **2026:** Rigid bipolar 866 MW
- **2028:** Rigid bipolar 866 MW
- **Best:** Rigid bipolar 866 MW
- **2030:** Rigid bipolar 3600 MW
- **2032:** Rigid bipolar 3600 MW
- **Chosen:** Rigid bipolar 3600 MW

**DK2**

- **3600 MW**
- **Poland 600 MW**
- **Bornholm 3000 MW**

---

**PROMOnO - Progress on Meshed HVDC Offshore Transmission Networks**

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 691714.
## 750 MW maximum allowed loss of infeed: 2a

### Best solution per installed power in 2025 and 2028 (scenario +4L, loss of infeed -25%)

<table>
<thead>
<tr>
<th>Project Name</th>
<th>Installed Power in 2025 (MW)</th>
<th>Installed Power in 2028 (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rigid bipolar 1000 MW</td>
<td>1000</td>
<td>1000</td>
</tr>
<tr>
<td>Rigid bipolar 500 MW</td>
<td>500</td>
<td>500</td>
</tr>
<tr>
<td>Metallic return 500 MW</td>
<td>500</td>
<td>500</td>
</tr>
<tr>
<td>DK2</td>
<td>3000</td>
<td>3000</td>
</tr>
</tbody>
</table>

### Power Grids
- **PROMOTiOn** - Progress on Meshed HVDC Offshore Transmission Networks

This project has received funding from the European Union’s Horizon 2020 research and innovation programme under grant agreement No 691714.
7.3.2.4 SENSITIVITY ANALYSIS CONSIDERING ENERGY PRICE VARIATION

Assumptions:
Energy price = 50€/MWh or 100€/MWh
MR = 0.33 * price(HV)
600 MW maximum allowed loss of infeed: 2a

Legend:
- 2020
- 2028
- Best

Price Energy = 50€/MWh

Price Energy = 100€/MWh

Hub: 320 kV

Bornholm: 3000 MW

Poland: 600 MW

DK2: 3000 MW

Rigid bipolar: 1000 MW
Rigid bipolar: 1000 MW
Metallic return: 500 MW
Rigid bipolar: 1000 MW

Diagram showing the energy solution per installed power in 2020 and 2028 with an all-loss of distributed power (2a). The red boxes highlight the best solutions.
600 MW maximum allowed loss of infeed: 2b

Legend:
- 2026
- 2028
- Best
- 100% New

Price Energy = 500/MWh

Price Energy = 1000/MWh

PROMOTiON – Progress on Meshed HVDC Offshore Transmission Networks

This project has received funding from the European Union’s Horizon 2020 research and innovation programme under grant agreement No 691714.
750 MW maximum allowed loss of infeed: 2a

Legend
- 2026
- 2028
- Best

Rigid bipoles: 1000 MW
Metallic returns: 500 MW
DK2: 3000 MW

PROMOnet - Progress on Meshed HVDC Offshore Transmission Networks
This project has received funding from the European Union’s Horizon 2020 research and innovation programme under grant agreement No 691714.
7.3.2.5 SENSITIVITY ANALYSIS CONSIDERING DIFFERENT MR COST

Assumptions:

Energy price = 50€/MWh

MR = 0.66 * price(HV)
### 600 MW maximum allowed loss of infeed: 1a

<table>
<thead>
<tr>
<th>Year</th>
<th>2028</th>
<th>2029</th>
<th>2030</th>
<th>2031</th>
<th>2032</th>
<th>2033</th>
<th>2034</th>
<th>2035</th>
</tr>
</thead>
<tbody>
<tr>
<td>0200</td>
<td>SMP 500 MW</td>
<td>SMP 500 MW</td>
<td>SMP 500 MW</td>
<td>SMP 500 MW</td>
<td>SMP 500 MW</td>
<td>SMP 500 MW</td>
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<td>SMP 500 MW</td>
</tr>
<tr>
<td>0202</td>
<td>SMP 500 MW</td>
<td>SMP 500 MW</td>
<td>SMP 500 MW</td>
<td>SMP 500 MW</td>
<td>SMP 500 MW</td>
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<td>SMP 500 MW</td>
<td>SMP 500 MW</td>
<td>SMP 500 MW</td>
<td>SMP 500 MW</td>
</tr>
</tbody>
</table>

---

**Diagram:**
- **Poland:** 1500 MW
- **DK2:** 1500 MW
- **Bornholm:** 3000 MW
600 MW maximum allowed loss of infeed: 2a
### 600 MW maximum allowed loss of infeed: 2b

#### Table: Installed power and loss of infeed (MW)

<table>
<thead>
<tr>
<th>Location</th>
<th>Installed Power (MW)</th>
<th>Loss of Infeed (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Poland 500</td>
<td>500</td>
<td>20</td>
</tr>
<tr>
<td>Poland 600</td>
<td>600</td>
<td>25</td>
</tr>
<tr>
<td>Poland 1000</td>
<td>1000</td>
<td>30</td>
</tr>
</tbody>
</table>

#### Graph: Best solution per installed power in 500 and 1000 (scenario = 154, loss of infeed = 104)

- **Legend**
  - 2026
  - 2028
  - Best

- **Networks**
  - Rigid bipolar 866 MW
  - Rigid bipolar 866 MW
  - Rigid bipolar 866 MW
  - Metallic return: 866 MW
  - Hub 320 kV
  - Bornholm 3000 MW

- **Countries**
  - Poland
  - 600 MW

---

**PROJECT REPORT**
### 750 MW Maximum Allowed Loss of Infeed: 2a

#### Table: Maximum Allowed Loss of Infeed

<table>
<thead>
<tr>
<th>Infeed</th>
<th>Maximum Allowed Loss of Infeed (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>SAP</td>
<td>0.82</td>
</tr>
<tr>
<td>EEX</td>
<td>0.59</td>
</tr>
<tr>
<td>TEP</td>
<td>0.67</td>
</tr>
<tr>
<td>DSR</td>
<td>1.03</td>
</tr>
<tr>
<td>DSR2</td>
<td>1.12</td>
</tr>
<tr>
<td>DSB</td>
<td>0.83</td>
</tr>
<tr>
<td>DSB2</td>
<td>0.95</td>
</tr>
<tr>
<td>DSB3</td>
<td>1.01</td>
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<td>1.08</td>
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<td>DSB8</td>
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<td>DSB9</td>
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<td>DSB10</td>
<td>1.52</td>
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<tr>
<td>DSB11</td>
<td>1.60</td>
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<tr>
<td>DSB12</td>
<td>1.67</td>
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<td>DSB13</td>
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<tr>
<td>DSB14</td>
<td>1.82</td>
</tr>
<tr>
<td>DSB15</td>
<td>1.89</td>
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<td>DSB16</td>
<td>1.96</td>
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<tr>
<td>DSB17</td>
<td>2.03</td>
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<td>DSB18</td>
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<td>DSB26</td>
<td>2.66</td>
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<td>DSB27</td>
<td>2.73</td>
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<td>DSB28</td>
<td>2.80</td>
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<tr>
<td>DSB29</td>
<td>2.87</td>
</tr>
<tr>
<td>DSB30</td>
<td>2.94</td>
</tr>
</tbody>
</table>

#### Diagram: Best Solution per Installed Power in 2025 and 2030 (Max Allow. Loss of Infeed x 750MW)

- SAP 500 MW
- EEX 120 MW
- TEP 700 MW
- DSR 500 MW
- DSR2 450 MW
- DSR3 400 MW
- DSB 750 MW
- DSB2 650 MW
- DSB3 550 MW
- DSB4 450 MW
- DSB5 350 MW
- DSB6 250 MW
- DSB7 150 MW
- DSB8 50 MW
- DSB9 50 MW
- DSB10 50 MW
- DSB11 50 MW
- DSB12 50 MW
- DSB13 50 MW
- DSB14 50 MW
- DSB15 50 MW
- DSB16 50 MW
- DSB17 50 MW
- DSB18 50 MW
- DSB19 50 MW
- DSB20 50 MW
- DSB21 50 MW
- DSB22 50 MW
- DSB23 50 MW
- DSB24 50 MW
- DSB25 50 MW
- DSB26 50 MW
- DSB27 50 MW
- DSB28 50 MW
- DSB29 50 MW
- DSB30 50 MW

**Legend:**
- **Legend:**
  - **Poland:** 600 MW
  - **DK2 3000 MW**
  - **Bornholm 3000 MW**
  - **Hub 320 kV**

**Note:** This project has received funding from the European Union’s Horizon 2020 research and innovation programme under grant agreement No 691714.
### 7.3.3 IMPLEMENTATION OF PROTECTION STRATEGIES

### 7.3.4 SELECTIVE FAULT CLEARING STRATEGIES
Protection Sequence – Line fault and breaker failure

Busbar connected with the failed breaker

- Line fault -> breaker failure
- Open adj. breaker
- Interrupt fault current
- Resume power
- End

Busbar connected with healthy breaker

- Fault identification
- Breaker operation
- Detect breaker failure
- Communication delay
- Adj. breakers operation
- Fault current decays
- “Zero” current DCCB trip
- Line isolated

Fault neutralization time 7ms (10ms)

0.5ms 2ms (8ms) 2ms 0.5ms 2ms (8ms) 5ms (10ms) 10ms
**Protection Sequence – Line fault**

Start → Detect and identify fault → Open both line DCCBs → Breaker failure detected?

- Yes: Line fault + breaker failure
- No: Interrupt fault current → Resume power → End

Remarks:
- Need to open 2 DCCBs
- "Resume power" could need actions from converter controls to ensure DC stability

---

**Line fault**

- Fault instant
- DCCB trip
- TVS rise
- "Zero" current
- RCB trip
- Line isolated

<table>
<thead>
<tr>
<th>Fault identification</th>
<th>Breaker operation</th>
<th>Fault current (decays)</th>
<th>RCB opening time</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>0.5ms</td>
<td>2ms (8ms)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>5ms</td>
<td>10ms</td>
</tr>
</tbody>
</table>

Fault neutralization time 2.5ms (8.5ms)
Protection Sequence – Busbar Fault

- Start
  - Detect busbar fault
  - Open all breakers
- Faulty busbar
  - Interrupt fault current
  - Resume power
- Healthy busbar

Fault instant
- Fault identification
- Booster operation
- Fault current decays
- "Zero" current
- RCD trip
- Busbar isolated

Fault neutralization time
- 2.5ms (0.5ms)

0.5ms 2ms 5ms 10ms
(8ms)
- Simplified circuit for DCR calculation during primary line failure sequence

Fault neutralization time of primary sequence

- Simplified circuit for DCR calculation during backup sequence (line fault + breaker failure)

Fault neutralization time of backup sequence

- Simplified circuit for Short time withstand current calculation:

Fault neutralization time of backup sequence
7.3.5 NON-SELECTIVE FAULT CLEARING STRATEGY BASED ON M-DCCB

Line fault

- Detect and identify fault
- Block open AC breaker of faulted line MCCM
- Block all other MCC

Faulted line

- Adjacent DCCB trip
- Open all line DCCBs except faulted line DCCB
- Breaker failure detected?
  - Yes
  - Open faulted line DCCB
  - Resume power
  - End
  - No
  - Faulted line
    - No
    - Fault clearance time
    - Fault clearing criteria
    - Resume power
    - End

Line fault

- Fault identification
- Fault current
- Breaker operation
- Faulted line RCBs trip
- Adjacent DCCB close order
- Resume power

Time (ms)
- 0.5
- 5
- 10
- 15
- 30
- 60
- 15
- 5
- 10

Fault clearance time
- ~ 50 ms

DCB O-C-O: 60ms
Line fault + breaker failure (breaker failure on faulted line)

Diagram showing the process of managing a line fault and breaker failure. The flowchart outlines steps such as detecting and identifying the fault, opening all line DCGBs, and determining if the breaker failure is on the faulted line.

Remark: Faulted line current decays even with line DCGB failure because adjacent DCGBs are opened.
Line fault + breaker failure (breaker failure on unfaulted line)

Interim fault current

Start → Detect and identify fault → Open all line DCCBs except faulted line DCCB → Breaker failure detected? → No → Line fault

Yes → Other line → Breaker failure detected? → Yes → Open both faulted line DCCB → Open both faulted line ROCB → Close all DCCBs except faulted line → Resume power → End

Faulted line → Faulted line DCCB

Faulted line + breaker failure on faulted line

DK2

50 mili DC reactor

Poland

Fault instant → Adjacent DCCB trip (open) →除外 for one breaker → Fault current → ROCB trip (open) → Faulted line current → ROCB trip (open) → Line related (Zero) current ROCB trips

Fault operation

Breaker operation

0.5 ms → 15 ms → 5 ms → 15 ms → 5 ms → 10 ms

Remark: faulted line current decays even with line DCCB failure because adjacent DCCBs are opened.

PROMOTIoN - Progress on Meshed HVDC Offshore Transmission Networks

This project has received funding from the European Union’s Horizon 2020 research and innovation programme under grant agreement No 691714.
Busbar fault (example with busbar 1+)

Remarks:
- Busbar coupler doesn't need to be a DCCB if we don't take into account the possibility of a busbar fault + breaker failure.

Remark: the case of one breaker failure is not considered.
Explanation of DCR specifications EMT studies
Line fault – worst case (fault on Bornholm-Poland line)

Considering a DCCB operation time of 15ms, DC inductors of 50mH in all lines would be sufficient in order to respect a short term current (STC) of 40kA in the busbar coupler DCR in case of line fault.

DCCB opens after 15 ms

STC in busbar coupler must be < 40 kA
Explanation of DCR specifications EMT studies
Line fault – worst case (fault on Bornholm-Poland line)

Considering a DCCB operation time of 15ms and a
current breaking capability of 20kA a DC inductance of
50mH is largely sufficient to open all adjacent
breakers in case of line fault.

With line DC inductors = 50 mH
Explanation of DCR specifications EMT studies
Busbar fault (1/2)

Considering a DCCB operation time of 15ms, a DC inductance of at least 70mH would be necessary in order to respect a STC of 40kA in the Bb coupler (no DC inductance in the Bb coupler)

STC in busbar coupler must be < 40 kA
Explanation of DCR specifications EMT studies
Busbar fault (2/2)

A cheaper solution to the busbar fault STC in Bb coupler problem:

Considering a DCCB operation time of 15ms, a DC inductance of 50mH combined with 10mH in the Bb coupler would be sufficient in order to respect a STC of 40kA in the Bb coupler.
Explanation of DCCB energy specifications EMT studies

DCCB energy absorbed

Line fault : worst case = Fault on BH – Poland line.
Worst case = 12.7 MJ.

DCCB energy absorbed

Busbar fault :
Worst case = 9.7 MJ.

DCCB rated energy absorption chosen : 15 MJ

DCCB model = ideal switch + surge arrester. Opens 15ms after fault.
7.3.6 KPIS CALCULATION

7.3.6.1 PERFORMANCE KPIS

7.3.6.2 ECONOMIC KPIS

Table 69, Table 70, Table 71 and Table 72 summarize the economic KPIs (CAPEX, EENT and losses) and a tentative of monetarization (discounted costs) with prince of energy set to 50 €/MW and 100 €/MW, discounted rate set to 8% and lifetime set to 30 years. Following conclusions can be drawn from these tables:

- Non selective protection strategy seem to be not competitive comparing to the other protection strategies and AC options. However, other benefits due to the use of full bridge converters (system services) should be taken into account to carry out a complete comparison.
- Full selective and non-selective protection strategies with mechanical DCCBs seem to be the best options in DC hub options. Particularly, the non-selective with mechanical DCCBs exhibits a lower CAPEX and discounted costs.
- DC hub options seem to be more competitive comparing to AC hub options. The only case in which AC hub is competitive is in scenario 1a and in case of low energy price (50 €/MW). However, in case of high energy price, the DC hub option becomes more competitive due to the low losses and EENT in this option.

Table 69 Summary results for scenario 1a with 750 MW maximum allowed loss of infeed

<table>
<thead>
<tr>
<th></th>
<th>DC Hub</th>
<th>AC Hub</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>FS-FDCCB</td>
<td>FS-SDCCB</td>
</tr>
<tr>
<td>CAPEX (M€)</td>
<td>1585</td>
<td>1474</td>
</tr>
<tr>
<td>EENT (MW)</td>
<td>17.97</td>
<td>17.97</td>
</tr>
<tr>
<td>Losses (MW)</td>
<td>52.88</td>
<td>53.05</td>
</tr>
<tr>
<td>EENT + Losses (MW)</td>
<td>70.85</td>
<td>71.02</td>
</tr>
<tr>
<td>Discounted costs</td>
<td>(50 €/MW - Discount rate 8% - 30 years)</td>
<td></td>
</tr>
<tr>
<td>(M€)</td>
<td>1847</td>
<td>1744</td>
</tr>
<tr>
<td>Discounted costs</td>
<td>(100 €/MW - Discount rate 8% - 30 years)</td>
<td></td>
</tr>
<tr>
<td>(M€)</td>
<td>2223</td>
<td>2121</td>
</tr>
</tbody>
</table>

Table 70 Summary results for scenario 1b with 600 MW maximum allowed loss of infeed

<table>
<thead>
<tr>
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<th>DC Hub</th>
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<tbody>
<tr>
<td></td>
<td>FS-FDCCB</td>
<td>FS-SDCCB</td>
</tr>
<tr>
<td>CAPEX (M€)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>EENT (MW)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Losses (MW)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>EENT + Losses (MW)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Discounted costs</td>
<td>(50 €/MW - Discount rate 8% - 30 years)</td>
<td></td>
</tr>
<tr>
<td>(M€)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Discounted costs</td>
<td>(100 €/MW - Discount rate 8% - 30 years)</td>
<td></td>
</tr>
<tr>
<td>(M€)</td>
<td></td>
<td></td>
</tr>
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</table>
### Table 71 Summary results for scenario 2a with 600 MW maximum allowed loss of infeed

<table>
<thead>
<tr>
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<th>DC Hub</th>
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</thead>
<tbody>
<tr>
<td>CAPEX (M€)</td>
<td>2134</td>
<td>2099</td>
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<tr>
<td>EENT (MW)</td>
<td>12.43</td>
<td>12.34</td>
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<tr>
<td>Losses (MW)</td>
<td>44.25</td>
<td>44.42</td>
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<tr>
<td>EENT + Losses (MW)</td>
<td>56.58</td>
<td>56.76</td>
</tr>
<tr>
<td>Discounted costs (50 €/MW - Discount rate 8% - 30 years) (M€)</td>
<td>2280</td>
<td>2165</td>
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<tr>
<td>Discounted costs (100 €/MW - Discount rate 8% - 30 years) (M€)</td>
<td>2580</td>
<td>2466</td>
</tr>
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</table>

### Table 72 Summary results for scenario 2b with 750 MW maximum allowed loss of infeed

<table>
<thead>
<tr>
<th></th>
<th>DC Hub</th>
<th>AC Hub</th>
</tr>
</thead>
<tbody>
<tr>
<td>CAPEX (M€)</td>
<td>2205</td>
<td>2080</td>
</tr>
<tr>
<td>EENT (MW)</td>
<td>11.18</td>
<td>11.18</td>
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<tr>
<td>Losses (MW)</td>
<td>45.77</td>
<td>45.95</td>
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<tr>
<td>EENT + Losses (MW)</td>
<td>56.95</td>
<td>57.13</td>
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</table>
7.3.7 EXTENSIBILITY

Figure 7-16 and Figure 7-17 show the total CAPEX (including initial hub CAPEX, cables, converters and protection equipment CAPEX) of the extended hub for the scenario 1b (600 LoI) and 2a (600 LoI) respectively. Figure 7-18 shows the additional CAPEX per installed power in SW and DE in case of 400 kV voltage rating.

**Discounted costs (50 €/MW - Discount rate 8% - 30 years) (M€)**

<table>
<thead>
<tr>
<th></th>
<th>2024</th>
<th>2025</th>
<th>2026</th>
<th>2027</th>
<th>2028</th>
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</thead>
<tbody>
<tr>
<td>Discounted costs (100 €/MW - Discount rate 8% - 30 years) (M€)</td>
<td>2650</td>
<td>2536</td>
<td>2785</td>
<td>2504</td>
<td>2590</td>
</tr>
</tbody>
</table>

Figure 7-16 Additional CAPEX for extended hub, scenario 1b 600 allowed loss of infeed:

- a) Extended power in SW=0 MW and in DE=600 MW,
- b) Extended power in SW=0 MW and in DE=1200 MW,
- c) Extended power in SW=1200 MW and in DE=1200 MW,
- d) Extended power in SW=1800 MW and in DE=1800 MW.

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**PROJECT REPORT**
Figure 7-17 Additional CAPEX for extended hub, scenario 2a 600 allowed loss of infeed:

a) Extended power in SW=0 MW and in DE=600 MW,  
b) Extended power in SW=0 MW and in DE=1200 MW,  
c) Extended power in SW=1200 MW and in DE=1200 MW,  
d) Extended power in SW=1800 MW and in DE=1800 MW
Figure 7-18 Additional CAPEX for extended hub reference and different installed powers in SW and DE (400 kV):

a) Loss of infeed 600 MW, b) Loss of infeed 750 MW, c) Loss of infeed 900 MW