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TECHNICAL REQUIREMENTS FOR CONNECTION TO HVDC GRIDS IN THE NORTH SEA

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Table of Contents

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1. PURPOSE OF THE DOCUMENT

The main outcome of this project is presented in a separate Companion Guide document. This Companion Guide was written to provide a clear set of recommendations on which stakeholders could provide their feedback. However, for the sake of clarity, the Companion Guide does not contain all details regarding the project. Therefore, this final report contains more information, such as the questionnaire sent to TSOs, the feedback received from stakeholders, a case study analysing the impact of DC protection, etc. The goal is not to repeat the messages already stated in the Companion Guide but to provide more details on how these messages have been reached.

It is worth noting that, in order to facilitate the reading of the document, many parts are included as appendices.

2. INTRODUCTION

2.1. Background

The development of offshore wind is key for meeting carbon neutrality in Europe by 2050. It is likely that more than 200GW of offshore wind will be installed in the North Sea and more than 450 in total in all European seas.

It has been shown in many studies that multi-purpose projects (such as evacuation of wind and cross-border interconnectors) can bring significant cost reductions to the offshore transmission infrastructure. In addition to these cost savings, these hybrid projects are a mandatory first step towards the eventual construction of more complex meshed offshore grid structures. Hybrid assets refer to offshore transmission infrastructure combining transport of offshore wind energy and cross-border transfer.

The recently agreed “Green Deal” emphasizes the importance of offshore grid in the European energy mix and it seems therefore very clear that hybrid assets will be developed over the next decade. However, many challenges still need to be addressed before the construction and commissioning of the first hybrid asset. These challenges cover regulatory, financial and technical issues. The scope of work addressed in this report discusses exclusively the technical requirements.

The following sections give more details on hybrid project topologies and the current status of the network codes in Europe.

2.1.1. *What is a hybrid project?*

A hybrid project, as defined in (Berger, 2019), is a combined transmission and generation asset that serves the two following purposes:

- Cross-border interconnection
- Evacuation of offshore wind

In other words, hybrid projects refer to offshore transmission infrastructure combining transport of offshore wind energy and cross-border transfer. This is therefore not a "technical" definition. However, the fact that hybrid projects are cross-border could result in a higher need for harmonization between national implementations of the European network codes.

The most likely, hybrid projects in the North Seas will be multi-terminal DC grids (MTDC grids), as shown in Figure 2-1, or radial point to point HVDC connections to an AC hub, shown in Figure 2-2.

According to the definition of the European network code, an MTDC grid is composed of a single **HVDC system**, while it is unclear whether radial HVDC connections to an AC hub can be defined as a single HVDC system. Therefore, the term **interlinked HVDC systems** is used for this latter configuration.

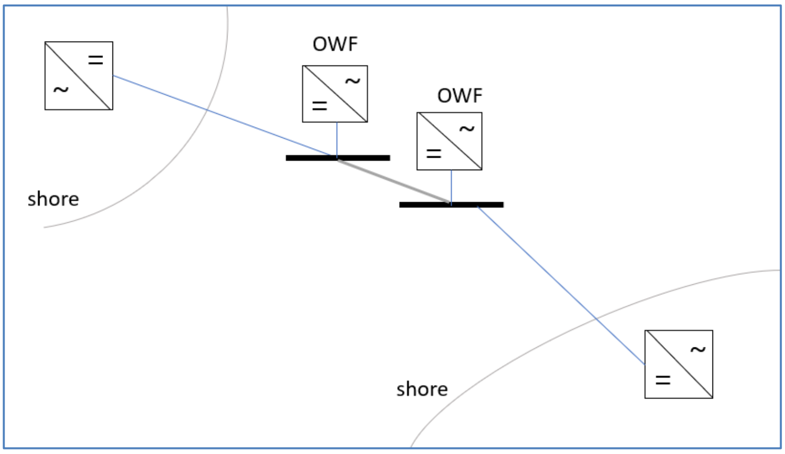

Figure 2-1: MTDC example

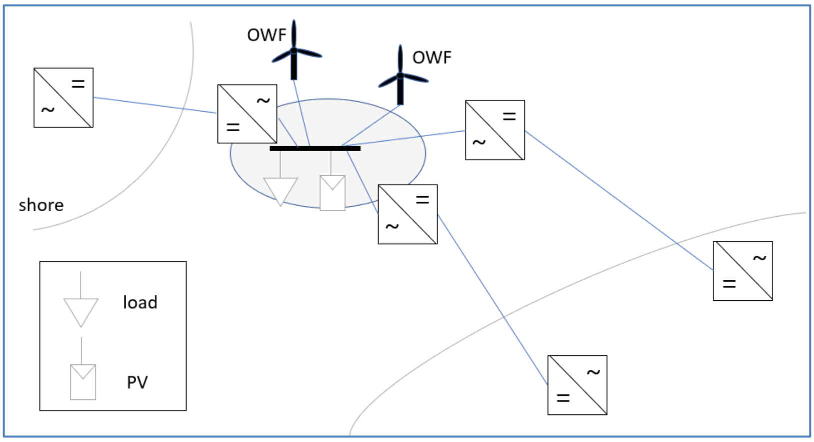

Figure 2-2: AC hub (or interlinked HVDC systems) example

2.1.2. *Current status of connection codes*

The current status of the European regulations on connection codes consists of the following three documents:

- The Requirements for Generators (RFG) code (European Commission, 2016) that harmonises standards that generators must respect to connect to the grid.
- The Demand Connection Code (DCC) (European Commission, 2016) that sets harmonised requirements for connecting large renewable energy productions plants as well as demand response facilities.
- The High Voltage Direct Current (HVDC) code (European Commission, 2016) that specifies requirements for long distance HVDC connections. In addition, it specifies requirements for DC-connected Power Park Modules (PPM).

These regulations are binding for all Member States (MS), however, several of the requirements are non-exhaustive, i.e. defined parameters are not assigned specific values. Instead, these parameters can be independently specified by each MS. This allows to take into consideration the particularities of each system and facilitates each TSO in designing and planning its own system.

However, it unavoidably leads to several different sets of requirements. This could pose barriers or risks in the development of hybrid HDVC projects, due to e.g. conflicting requirements or incompatible designs.

In order to facilitate the development of these hybrid assets, it is important to put in place a set of technical requirements that need to be met by each electrical component. This will allow the manufacturers to select/develop the right piece of equipment compliant to these requirements. That will also allow investors to better determine the price of a project and therefore reduce risks. Lastly, having standardized technical requirements is a way to ensure interoperability between equipment of different manufacturers.

It is important to determine the set of rules in an objective and independent manner. This set of rules must consider the four following dimensions:

- The technical capabilities of each piece of equipment;
- Expected behaviour (e.g. voltage and current) on the offshore assets for:
- different HVDC technology choice (e.g. voltage, bipole or monopole configuration, etc.);
- different protection strategy;
- different control modes;
- Expected impact on the onshore AC grid;
- Expected impact on the offshore AC grid (such as offshore wind farms and potential storage facilities).

There are still uncertainties on the maturity level and technical capabilities of some potential components of hybrid assets (such as DCCB, large-scale P2G, etc.). To mitigate these uncertainties, significant effort has been put to include stakeholder consultation and discussions with key players during the different stages of this project.

2.2. Objective of the assignment

The objectives of the project were to identify technical barriers coming from lack of harmonization or gaps in the existing network code, and assess their removal by proposing a set of common rules or technical guidelines.

This would ensure harmonization between Member States, which will then provide clarity for investors, TSOs and manufacturers. This is an important step to enable and facilitate the building of hybrid projects.

2.3. Structure of the document

The document is structured as followed. First the methodology is described, the methodology has been slightly adapted during the project and this is also detailed. Secondly, the main findings are presented for each task in Section 4. Finally, the main conclusions are presented.

3. METHODOLOGY

To reach the objective, the assignment was divided into the three following tasks:

- Task 1: Map the grid connection requirements of the North Sea countries, pursuant to the provisions in the RfG NC, HVDC NC and DCC NC.
- Task 2: Analysing national variations and proposing a set of common rules.
- Task 3: Workshop.

The flowchart of Figure 3-1 gives an overall view of the three main tasks in the project. These are further described in the following sections.

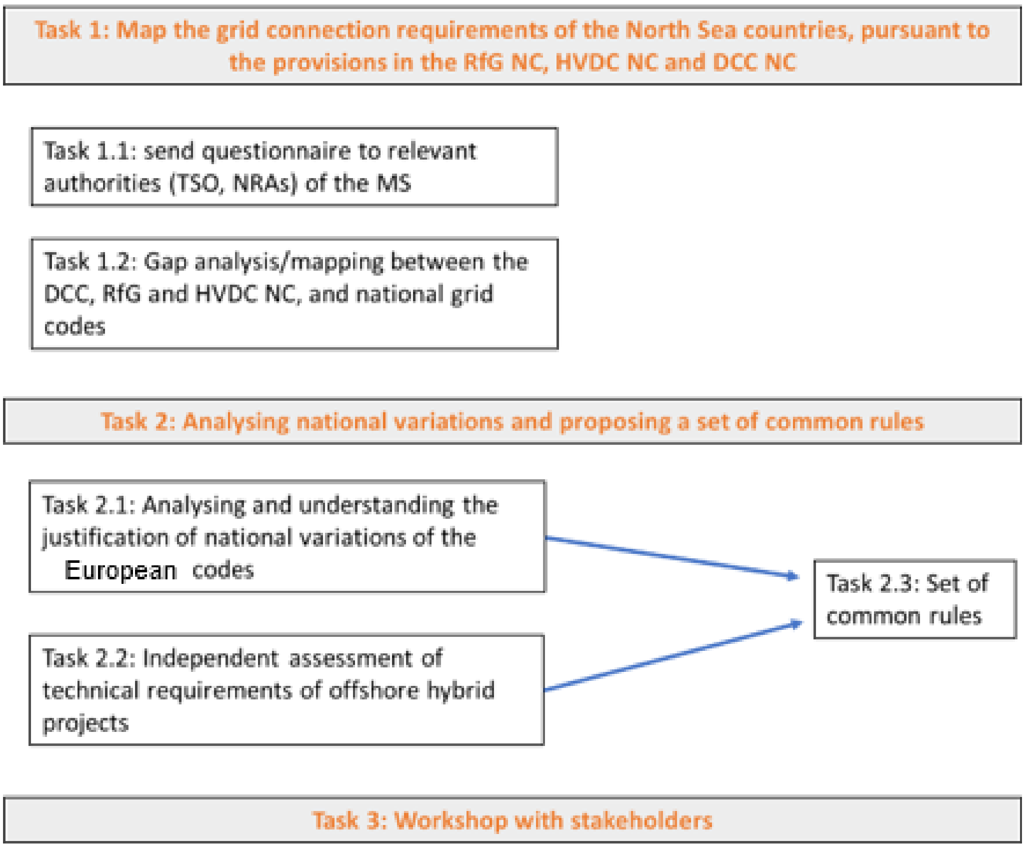

Figure 3-1: Specific and complementary tasks

3.1. Task 1: Map the grid connection requirements of the North Sea countries pursuant to the provision in the RfG NC, HVDC NC and DCC NC

The preparation of a dedicated questionnaire is central in this task. This questionnaire was created after a thorough analysis of the European network codes. This analysis was performed by considering the potential impact of each article on hybrid projects. Therefore, only articles for which non-harmonization would impact hybrid project have been selected.

For each of these pre-selected articles, more details on the national implementation have been pre-filled in the questionnaire and dedicated questions have been drafted for each of these articles.

The last step of Task 1 was to send the questionnaire to the following TSOs; RTE, Elia, TenneT NL, TenneT DE, Amprion, EirGrid, Stattnett, SvK, Energinet, National Grid.

3.2. Task 2: Analysing national variations and proposing a set of common rules

The main aim of Task 2 was to come up with a set of common rules that would facilitate the development of hybrid projects. The tasks described in Figure 3-1 can be further expanded into the following actions:

- Analysis of the answers to the questionnaire, followed by dedicated meeting to have a better understanding on the national implementation
- Literature review
- Simulations on a case study for analyzing the impact of DC grid protection on functional requirements when extending or interconnecting hybrid assets
- Propose a set of common rules/technical guidelines

3.3. Task 3: Workshop(s)

The third task consisted of the organization of a workshop in order to draw attention to the Companion Guide and invite the operators and relevant stakeholders to provide their feedback on the recommendations.

3.4. Adjustment of the methodology during the project

As expected at the start of the project, it has been confirmed that the three proposed tasks are not fully independent, and actually closely interlinked.

During the project, it has been agreed to adjust task 3 by proposing two workshops instead of a single workshop as originally planned. This has led to the organisation of a first workshop early in the project. The objective of this workshop was to already involve the stakeholders and receive feedback on the scope and methodology. This workshop, in addition to regular meetings with the European Commission, allowed to fine-tune the methodology. This had the impact to slightly adapt Task 2 where more emphasis was drawn on literature review (e.g. CENELC work) and expert consultation than on analysing study cases via simulations.

Also, this first workshop allowed to converge on the structure and content of the Companion Guide document. By consequence, it has been to include all practical recommendations, for harmonization or for filling a gap in the regulation, in this Companion Guide. This document was then opened for consultation for a limited period after the second workshop.

4. Overview of project tasks and main findings

4.1. Task 1: Map the grid connection requirements of the North Sea countries pursuant to the provision in the RfG NC, HVDC NC and DCC NC

During the first task, significant effort was invested into assessing the relevance of the existing connection code requirements for hybrid assets. The starting point for the analysis were the existing grid codes. In particular, the HVDC NC was identified as the most relevant for hybrid projects and the main focus of the work in this project.

As far as the RFG and DCC NC are concerned, they have been identified as particularly important for the case of an AC hub (see Figure 2-2), hence a gap analysis was performed in order to assess their relevance and applicability.

4.1.1. Study of HVDC NC – Preparation of questionnaire

A first assessment of the impact of individual articles and national variations on the development of hybrid assets was performed based on the monitoring document published by ENTSO-E (ENTSO-e, Monitoring report, n.d.). Each article was assigned a grade based on:

- how important it is perceived for hybrid projects, and
- the level of non-harmonization between the various national implementations.

This resulted in a total of 28 articles or sub-paragraphs in the HDVC NC (or in the RFG but referred to in the HVDC NC).

The next step was to draft the questionnaire to be sent to ENTSO-e and the relevant TSOs. The questionnaire was split into two parts:

- The purpose of part A was to investigate the national variations, as well as the reasoning behind them, i.e. "what drove the choice of the parameter values?". This part consisted of question on each of the identified articles of the HVDC NC.
- The purpose of part B was to investigate the need for additional technical requirements to cover gaps in the existing HVDC NC, i.e. "what is further needed to cover the case of hybrid projects?". Part B included a set of high-level questions.

The main body of the Questionnaire can be found in Appendix A. The questions of Part A and Part B are provided in separate files.

4.1.2. Gap analysis of RFG NC and DCC NC

The RFG NC and DC NC discuss the connection of the generators and demand to an AC system. The drafting of these codes was a result of decades of experience on conventional AC systems and of years of discussions and consultations.

However, their scope of application does not include power-generating models or demand connected to systems that "are not operated synchronously with either the Continental Europe, Great Britain, Nordic, Ireland and Northern Ireland or Baltic synchronous area". As a result, more clarity is necessary for AC hubs, which are not synchronously connected to one of the aforementioned areas. This clarity is a prerequisite to be able to arrive to clear connection requirements to an AC hub.

Therefore, the gap analysis of the RFG and DCC network codes focused first on a comparison between conventional AC systems and AC hubs. The purpose of this comparison is to illustrate the different challenges that AC hubs are expected to face. The main difference with conventional AC systems is clearly the dominance of Power-Electronics Interfaces Power Sources (PEIPS) instead of synchronous machines. Due to the inherent differences in behaviour of the PEIPS this gives rise to several new technical challenges. As a result relevance of the existing network codes for AC hubs has to be revisited and assessed.

4.2. Task 2: Analysing national variations and proposing a set of common rules

The main aim of Task 2 was to come up with a set of common rules that would facilitate the development of hybrid projects. The analyses performed in each subtask of Task 2 are further detailed in the next sections.

4.2.1. Task 2.1: Analysing the answers to the questionnaire

The vast majority of the TSOs responded in a timely manner to the questionnaire. The answers are provided in Appendix A. These answers were discussed during a dedicated meeting with the ENTSO-E connection network code working group.

The main conclusions from the answers, i.e. level of harmonization and impact of non-harmonization, have been summarized in the Companion Guide, provided in Appendix F. The following general conclusions were derived:

- The main scope of the HVDC NC was point-to-point connections.
- The HVDC NC is much less mature for complex HVDC topologies.
- Existing requirements referring to more complex HVDC topologies are still expressed at a very generic level.
- In several occasions, the national implementations define site-specific (or project-specific).
- The TSOs acknowledge the increased need of coordination required between them, as well as other stakeholders, in the case of HVDC systems. This need for coordination is expected to become even more important for hybrid and more complex topologies.
- There is not always a common methodology to specify the non-exhaustive parameters of the HVDC NC articles.

4.2.2. Task 2.2: Independent assessment of technical requirements

4.2.2.1.Literature review

The possible future hybrid projects shown in Figure 2-1 and Figure 2-2 relate to MTDC grid and AC hub topologies from which there is limited, if any, experience from real-life projects. Therefore, several challenges of these systems are still at research level and have yet to be addressed. Several of these challenges are mentioned in Chapters 6 and 7 of the Companion Guide. Examples include:

- Protection of Multi-Terminal DC grids;
- Interoperability of multi-vendor HVDC systems
- Stability and control of inertia-less AC hubs
- Sharing of appropriate simulation models

Therefore, due to the limited practical and operational experience on hybrid topologies, literature review of the state-of-the-art and experience collected from various European research projects was the main source of information towards drafting the recommendations.

Recommendations should be sufficiently future-proof and technology-neutral. They should take into account the technological capabilities of equipment available today, but also encourage and leave room for future developments.

By relying on several sources by experts on the subject it was possible to draft a list of meaningful and objective recommendations. Particular attention was given to the following references:

- CENELEC, HVDC Grid Systems and connected Converter Stations – Guideline and Parameter Lists for Functional Specifications, 2020.
- CIGRE, “TB B4/B5 Protection and local control of HVDC grids,” 2018.
- Best Paths Demo#2: Final Recommendations for Interoperability of Multivendor HVDC systems,” 2018.

- ENTSO-E, "High Penetration of Power Electronic Interfaced Power Sources and the Potential Contribution of Grid Forming Converters".
- "Multi-DC project," [Online]. Available: www.multi-dc.eu/.
- CIGRE WG B4.56, "Guidelines for the preparation of "connection agreements" or "grid codes" for multi-terminal DC schemes and DC grids," 2016.
- C. Plet, "Progress On Meshed HVDC Offshore Transmission Networks (PROMOTioN)," InnoGrid, 18 June 2020.
- R. Ierna and A. Roscoe, "Effects of VSM / Option 1 (Grid Forming) Convertor Control on Penetration Limits of Non-Synchronous Generation (NSG) in the GB Power System," 2017.

A complete list of the sources can be found in the Bibliography section of the Companion Guide.

4.2.2.2.Case study for analyzing the impact of DC grid protection on functional requirements when extending or interconnecting hybrid assets

The interruption of DC fault currents is a critical point that has to be resolved in order to allow more complex topologies. Compared to AC faults, DC fault current does not exhibit a natural transition from zero that allows to eliminate the electric arc when opening the breaker. Instead, complex mechanisms have to be developed in order to create an artificial zero-current crossing. Moreover the detection and the elimination of the faulty line have to be fast enough to sufficiently reduce the fault current before it can be cleared.

In the point-to-point HVDC case using VSC converters, fast HVDC protection is not required and can be realized through AC breakers. This implies a shutdown of the HVDC systems during at least a few seconds. This could pose an unacceptable risk for MTDC grids transferring high amounts of power (several GW) from offshore WFs to shore or between AC systems. Therefore, DC protection mechanisms will most likely be required for MTDC grids.

The development of an MTDC grid involves many technical challenges, from planning to connection and operation as shown in Figure 4-1. It is important to note that, because of the lack of practical experience, it is unclear whether connection requirements can be proposed independently of the HVDC grid design and protection strategy. In fact, the choice of the protection strategy in an HVDC is strongly impacted by several aspects, a critical of which is to be able to comply with requirements on the AC side (e.g. prevent losing more power than the maximum loss of infeed). On its turn, the protection strategy impacts strongly several design choices in an MTDC grid, such as:

- The DC grid architecture, e.g. the choice between bipole or symmetric monopole configuration;
- The earthing/grounding of the MTDC grid;
- The converter technology, e.g. half-bridge vs full-bridge Modular Multilevel Converters
- The switching equipment requirements, i.e. DC circuit breakers, DC current limiting reactors, etc.
- The power restoration after a DC fault

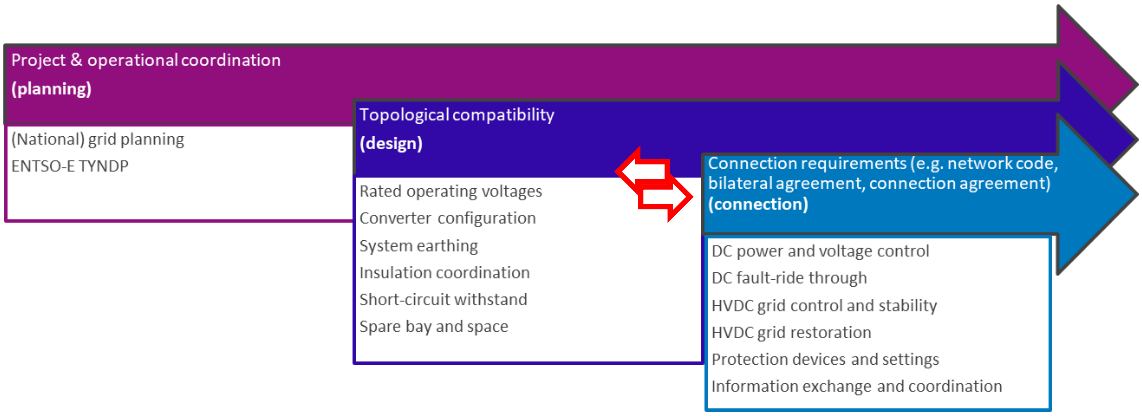

Figure 4-1: Challenges to MTDC grid development

In order to illustrate this impact of the protection strategy, a case study has been conducted in collaboration with SuperGrid Institute using ElectroMagnetic Transient (EMT) simulations. The EMT simulations are performed on the simple yet realistic MTDC grid shown in Figure 4-2.

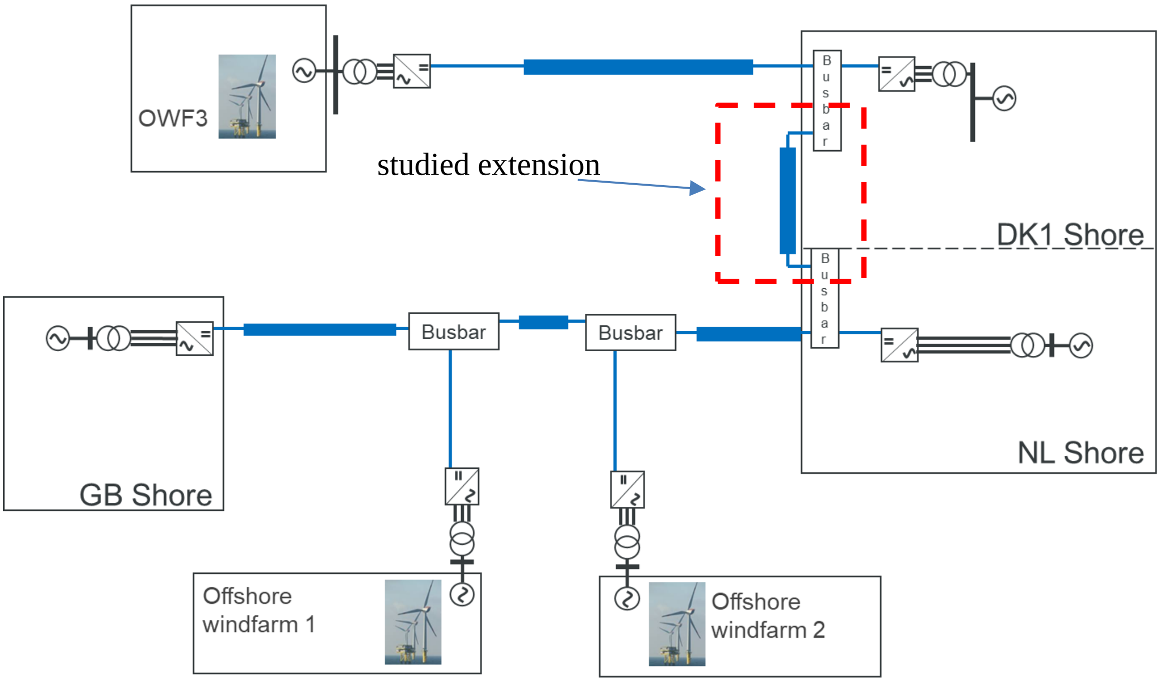

Figure 4-2: Test system used in protection case study

Based on the above system, simulations of a DC fault were carried. Different configurations and protection strategies were tested including:

- full-selective fault clearing;
- non-selective fault clearing
- bipole configuration;
- symmetric monopole configuration.

For further information on the case studies considered and on the details of the simulations (e.g. MTDC modelling and configuration), the interested reader is referred to the report from SuperGrid Institute, provided along with this report in Appendix E. Hereafter, a subset of the main findings is listed :

For the full-selective protection strategy:

- A grid extension could have significant impact on the design of the existing breakers, if the extended grid is realized through short cables or if there is a high number of new converters close to an existing breaker. Nevertheless, an optimized choice of the DC limiting reactor value could decrease this impact by increasing the electric distance between the two interconnected grids after a new extension.
- The breaker requirements considering the primary protection sequence are not always more restrictive compared to the backup protection sequence. In fact, the backup protection requirements could be more restrictive (i) in case of several MMCs and lines connected to the same node (ii) if the backup breaker takes very long time to act (e.g. 10 ms) or (iii) if the DC reactor of the line has low value.

For the non-selective protection strategy:

- The extension of the grid seems to have low impact on the energy requirement of the breakers.
- DC line reactors may still be necessary to be installed in some locations to avoid extremely high currents and equipment damage.
- The power flow in the entire MTDC grid stops during the fault. Converter controls have to be coordinated in order to restore reliably the power after the fault clearing.

On the voltage rebalancing and insulation coordination for symmetric monopole configuration:

- After a fault, the MTDC grid may split into several sub-networks. When symmetric monopole is used, pole rebalancing equipment has to be installed in several MTDC grid locations to ensure there is at least one rebalancing device in each sub-network.
- When two networks are connected together (see extension in Figure 4-2), the voltage-current characteristics of surge arresters must be similar in both subnetworks in order to have a balanced share of the energy to be dissipated after pole to ground fault.

Impact on PoC DC:

The results of the study case confirm that additional practical experience is an important prerequisite for MTDC grid protection requirements. Without this experience and given the large number of design choices with similar costs, it is impractical to define specific and more detailed regulations to apply on all HVDC systems.

4.2.3. Task 2.3: Recommended actions and guidelines

The last and main objective of Task 2 was to convert the analysis performed during the aforementioned tasks into concrete recommendations and common rules.

In order to facilitate understanding, these recommendations were split according to the Point of Connection (PoC) on which they should apply or for which they are relevant. This split was performed in order to provide clarity and be consistent with the European network codes and CENELEC standards.

Therefore, recommendations are provided on the following three key points of connection:

1. Connection at the **onshore AC grid** point
2. Connection at the **DC grid** point
3. Connection at the **offshore AC grid** point

The level of maturity and relevance of network codes differ significantly for each of these points of connection. This is reflected to the recommendations, which can sometimes be interpreted as specific proposals to amend existing network code articles, and sometimes as high-level guidelines that have to be further investigated. In any case, **these recommendations are not binding**.

4.2.3.1. Connection to onshore AC grid (PoC-AC)

Regarding the connection at the onshore AC grid, it can be concluded that the existing HVDC network code covers most of the technical requirements and has been carefully written in order to be future-proof for more complex offshore topologies. However, variations in the national implementations of the European network codes might negatively impact the development of hybrid projects.

The recommendations concern the HVDC NC articles that were identified in Task 1 of potentially impacting hybrid projects. Further assessment of the possible impact of non-harmonization was performed, and a follow-up action was proposed, as follows:

- High-impact articles: These correspond to articles where non-harmonization could really become a blocking point for the development of hybrid projects. Harmonization in these cases is considered important. The need for more operational experience in some aspects was also highlighted.
- Medium-impact articles: Harmonization in these cases is considered beneficial, but not necessary. It was identified that differences in the national implementations could be resolved either by increased coordination between the relevant operators or by specifying additional requirements on the DC side of the HVDC systems.
- Low-impact articles: Harmonization can be avoided by maintaining coordination between the relevant operators.

A total of 16 recommendations are made based on the HVDC NC articles that were identified in Task 1 as especially important for hybrid projects. Each recommendation follows the format shown in Table 4-1:

NC Article No.	Topic	Current Degree of Harmonization	Impact of Non-harmonization	Proposed Action

Table 4-1: Format of recommendations for connection to PoC-AC

where:

- First, the **article** of the HVDC NC to which the recommendation refers to is provided (if applicable).
- The relevant **topic** in which the recommendation falls into following the structure of the HVDC NC:
  - Active power control and frequency support;
  - Reactive power control and voltage support;
  - Fault ride-through capability;
  - Other control schemes related to AC grid;
  - Power system restoration;
  - Protection devices and settings;
  - Information exchange and coordination.
- The **current degree of harmonization** gives details on where the variations between MS are observed.
- The **impact of non-harmonization** describes which aspect of a hybrid project is likely to be affected.
- The **proposed action** describes how the impact can be mitigated, without necessarily suggesting network code amendments.

4.2.3.2.Connection to DC grid (PoC-DC)

The recommendation for the PoC-DC consist of high-level guidelines in order to address the various technical challenges associated with HVDC grids. It is not recommended to integrate these guidelines in a network code at the current stage because of the still relatively low level of maturity of multi-terminal HVDC grids. Writing technical requirements in a legal document seems too early in the development of the technology, and could be counterproductive as it might negatively influence technological choices and creativity of manufacturers. In addition, it was the opinion of several stakeholders that a DC grid code will eventually be required, but more operational experience and technical maturity has to be reached before drafting requirements

A total of 15 recommendations were made on different aspects of HVDC grids following the format of Table 4-2:

Topic	Challenge	Proposed guideline

Table 4-2: Format of recommendations for connection to PoC-DC

where:

- The **topic** relevant to the requirement is given among the following (a similar structure as the HVDC NC has been pursued):
  - DC power and voltage;
  - DC fault ride-through;
  - HVDC grid control and stability;
  - DC grid restoration from blackout;
  - Protection devices and settings;
  - Information exchange and coordination.
- The **challenge** to be addressed by the recommendation is described;
- The **proposed guideline** is summarized.

4.2.3.3.Connection to offshore AC grid (Off PoC-AC)

The last point of the analysis concerned the connection to offshore AC hubs. Based on the gap analysis performed in Task 1, guidelines are proposed to bridge those gaps and address the challenges of an AC hub. These guidelines refer to:

- Connection of new generating units;
- Connection of demand and loads;
- Connection of remote-end converters.

The guidelines are inspired by articles in the existing network codes (RfG, DCC and HVDC), and discuss how they should be adjusted to tackle the challenges in an AC hub. Therefore, their format is as shown in

RfG/HVDC/DCC NC Article No.	Article Topic	Challenges	Potential Gap

Table 4-3: Format of recommendations for connection to offshore PoC-AC

where:

- First, the **article** of the RfG/HVDC/DCC NC for which the gap was identified is given.
- The **topic** in which the article falls in is the second entry. Several topics were identified, among which:
  - Frequency ranges;
  - General voltage requirements
  - Frequency Sensitive Modes (limited or not);
  - Protection requirements.
- The **challenges** that prevent the direct extension of existing grid codes requirements to AC hubs.
- A description of the **potential gap** in the current network connection codes, as well as a guideline to resolve this gap.

4.3. Task 3: Workshops and stakeholder consultation

The third task consisted of the organization of a workshop in order to draw attention to the Companion Guide and invite the operators and relevant stakeholders to provide their feedback on the recommendations.

Initially, a single workshop was planned. However, following discussions with the European Commission, it was agreed to prepare two workshops, as discussed in the next sub-sections.

Several questions and remarks were raised during the workshops and are provided in Appendix B. These questions have been addressed in the Companion Guide.

4.3.1. Workshop 1 on 02/07/2020

The objective of the workshop was to already involve the stakeholders and receive feedback on the scope and methodology.

It attracted the attention of several stakeholders and interested parties with a total of 55 participants. The chart in Figure 4-3 shows the composition of the participants by sector. The chart demonstrates the importance of the topic for TSOs and energy producers, as well as the interest it poses for the R&D community.

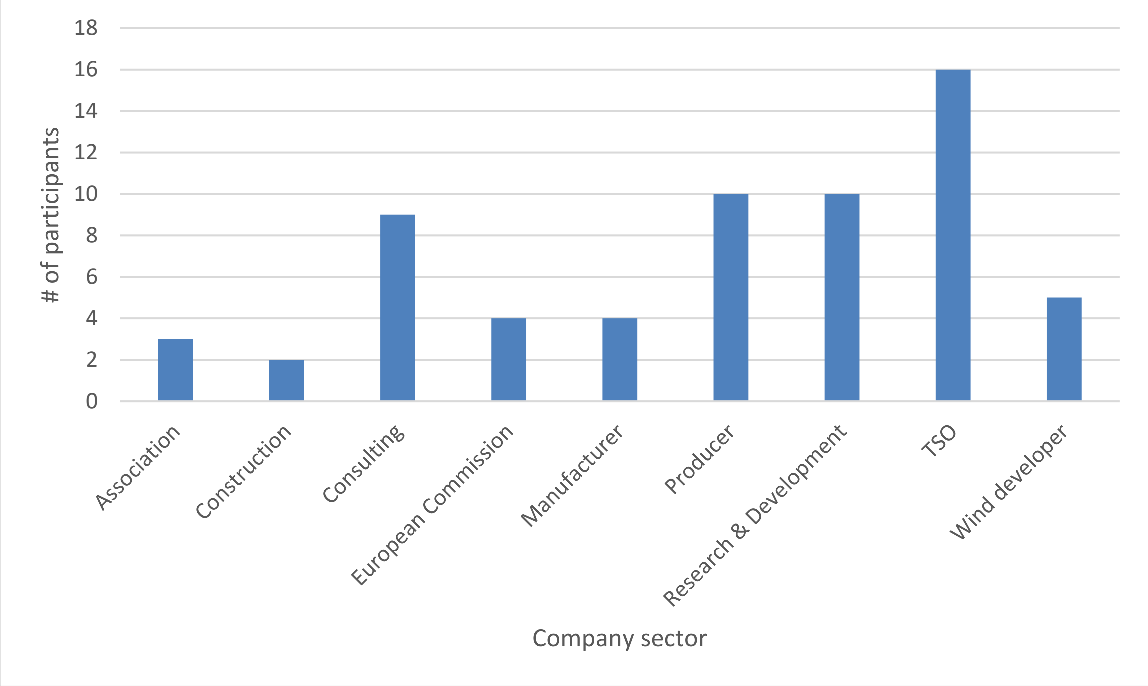

Figure 4-3: Participants per sector of workshop 1

The duration of the workshop was 1 hour and 30 minutes. The agenda was as follows:

- Introduction by European Commission;
- Background and objectives;
- Methodology description
- Expected outcomes from the project;
- Next steps and call for feedback;
- Q&A.

4.3.2. Workshop 2 on 31/08/2020 and 02/09/2020

The objective of the second workshop was the presentation of the draft version of the Companion Guide, and the opening of the consultation period for stakeholders to provide their feedback.

The total participation amounted to 57 people from different sectors. The composition of the audience is shown in the chart of Figure 4-4. As in the first workshop, TSO representatives consisted the larger part of the audience. In addition, there was significant representation by the manufacturing community (i.e. manufacturers of HVDC equipment). Academic and R&D institutes also consisted a large part of the participants. Finally, compared to the first workshop, there was significant participation from regulating authorities.

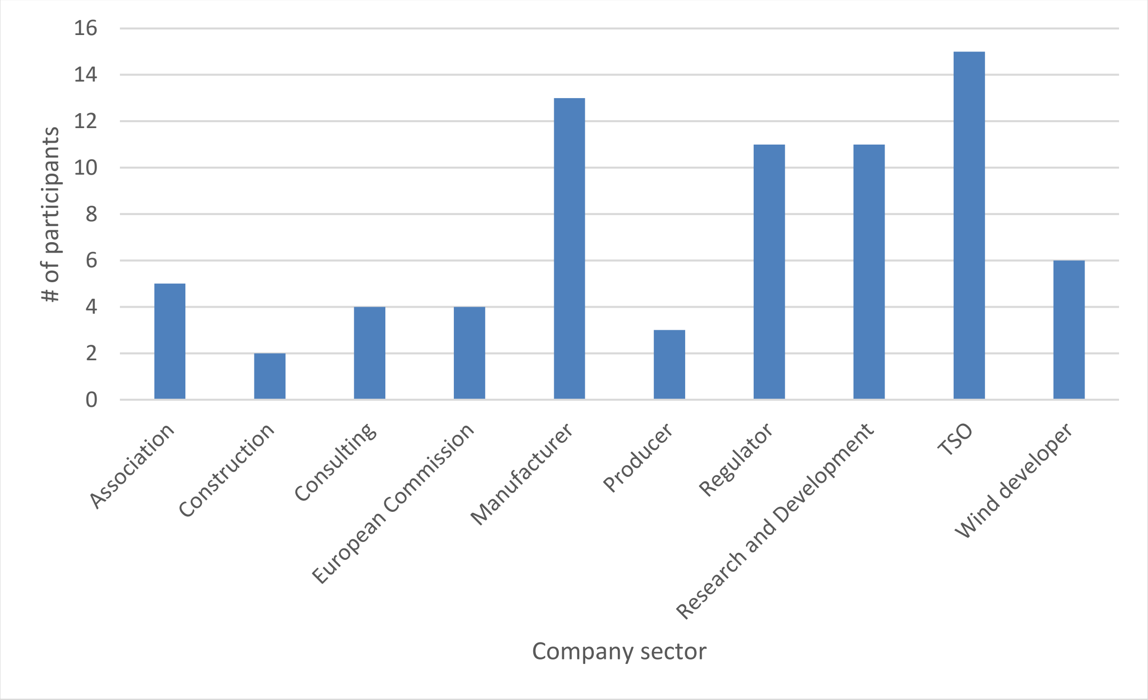

Figure 4-4: Participants per sector of workshop 2

The workshop lasted for a total of 2 hours and followed the agenda below:

- Introduction to project by European Commission;
- Introduction, challenges and methodology description;
- Presentation of Companion Guide:
- Connection to onshore AC grid + Q&A
- Connection to DC grid + Q&A;
- Connection to offshore AC grid + Q&A;
- Closure of the workshop.

4.3.3. Stakeholder consultation

Consultation with stakeholders was of crucial importance in order to ensure consistency and clarity for any recommendations. To this purpose, significant effort was made to involve the relevant stakeholders in the procedure. This was achieved by arranging two rounds of stakeholder consultation. All feedback received are shown in Appendices C and D.

The first round of consultations took place after the first workshop and concentrated on clearly defining the scope of the project and identifying attention points that should be tackled during the analysis in Task 2. The following discussions were arranged:

- ENTSO-e and TSOs: a virtual meeting took place on 02/07/2020.
- T&D Europe: a virtual meeting took place on 16/07/2020.
- WindEurope: a virtual meeting with WindEurope representatives took place on 14/07/2020.

The second round of consultation opened immediately after the second workshop and the publication of the draft version of the Companion Guide. The aim was to receive feedback on the overall content of the Companion Guide and the recommendations listed in it. Due to strict timelines that imposed a relatively short second consultation period, a consolidated response by some of the stakeholders was not possible. This has been highlighted in the stakeholder comments and in the Companion Guide. The following meetings were arranged:

- TSO experts: two meetings with TSO experts on HVDC technology and Network Codes were arranged on 10/09/2020 and on 11/09/2020.
- T&D Europe: a second virtual meeting with representatives from T&D Europe took place on 15/09/2020.

Additional feedback was received by email by the following stakeholders:

- ENTSO-E on 09/09/2020: Note that this is not a consolidated response by ENTSO-E, but a high-level view of the opinions experts involved in ENTSO-E and TSO connection code activities.
- WindEurope on 18/09/2020.

The main comments and questions raised during the meetings or by email during the consultation period are provided in Appendices C and D. Note that in order to preserve the anonymity of the participants, names and affiliations have been removed.

The following general comments are highlighted:

- The workshops and consultation process were generally well received by all stakeholders. It was mentioned that the comments received in the first round of consultation were integrated in the draft version of the Companion Guide. Most of the stakeholders outlined the complexity of the work and agreed with the relevance to shed light on some technical issues that could slow down the development of hybrid projects.
- Most of the feedback received focused on the DC point of connection chapter, meaning that this an important point of attention for the stakeholders. On that aspect, most of the comments were in favour of a collaborative approach to gain more practical experience before drafting an updated or dedicated grid code on the DC point of connection.
- Some comments also pointed out the importance of defining clear roles and boundaries when developing HVDC grids. Currently, in point-to-point HVDC connections the DC side is the responsibility of the vendor, whereas in multi-terminal HVDC grids (especially in multi-vendor systems) the DC side will most likely be the responsibility of the TSO or a non-TSO operator. This constitutes a big shift in mentality. Some existing roles might have to be redefined or additional roles might need to be created. In addition, these roles, the responsibilities and the ownership status of a DC grid will have to be clearly defined. This is a very important remark, but is out of scope of this document, which focuses only on the technical aspects.

5. Conclusion and main outcomes

This report has summarised the main content of the Companion Guide and provided more details on the methodology and different steps taken throughout the project.

The work was split between three closely interlinked tasks involving literature review, stakeholder consultation, expert input, TSO responses to questionnaire, a case study on DC grid protection and two workshops.

The main outcome of the work is **in the form of recommendations and have been published in the Companion Guide** (see Appendix F). Their aim is to be used by

TSOs, manufacturers, relevant stakeholders and regulating authorities either as basis for harmonization work on existing network codes or as foundation for future network code after further investigation. The final goal is to facilitate the extension and development of hybrid and more complex topologies in the North Sea.

The aforementioned recommendations were split into three different categories: (i) connection to onshore PoC AC, (ii) connection to PoC DC, and (iii) connection to offshore PoC AC.

As far as the onshore PoC AC is concerned, specific articles of the HVDC NC were identified as very important for hybrid connections. To limit the impact of these articles on hybrid system follow-up actions are recommended. In some cases, harmonization of the different national variations was among the proposed actions.

As far as the PoC DC and the offshore PoC AC are concerned, a list of challenges is highlighted and a set of guidelines is proposed. It is recommended that grid code amendments are not the priority for these points of connection. Nevertheless, in a second stage of development (e.g. after gaining experience from pilot projects), grid codes will be eventually required. It is thus recommended to develop these grid codes in the most possible collaborative way between all stakeholders.

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7. APPENDIX A – QUESTIONNAIRE

A copy of the questionnaire that was submitted to the North Sea TSOs can be seen in section 7.1. The answers of the TSOs are also provided in sections 7.2 and 7.3.

7.1. Main body of questionnaire

Purpose of the project: "Technical requirements for connections to offshore HVDC grids in the North Sea"

The development of offshore wind is key for meeting carbon neutrality in Europe by 2050. It is likely that more than 200GW of offshore wind will be installed in the North Sea and more than 350 GW in total in all European seas. It has been shown in many studies that **multi-purpose hybrid projects** (combining evacuation of wind and cross-border interconnection) can bring significant cost reductions to the offshore transmission infrastructure. In addition to these cost savings, these hybrid projects are **a mandatory first step** towards the eventual construction of more complex **meshed offshore grid structures**.

Some examples of possible hybrid projects have been identified in the study performed by Roland Berger (Roland Berger GMBH, 2019) and are illustrated in Figure 7-1.

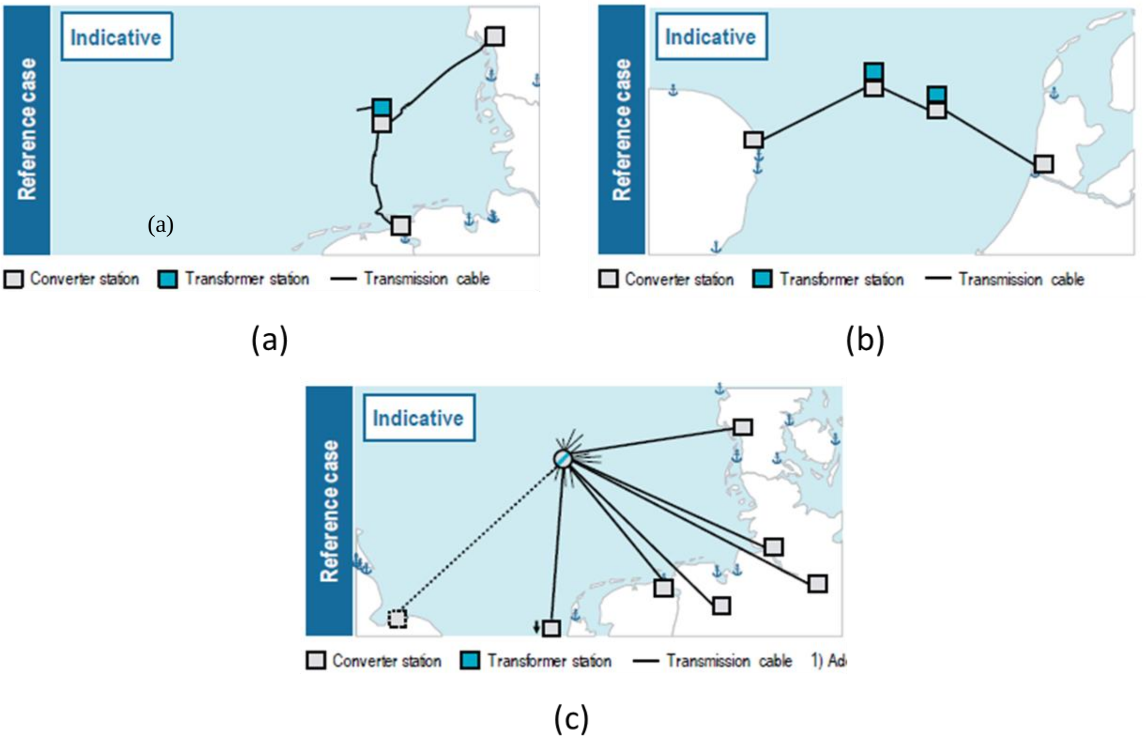

Figure 7-1: Examples of hybrid projects

The extension of a simple point-to-point HVDC connection to a hybrid one does not necessarily follow a single path. For example:

- In Figure 7-1(a), the offshore wind farm (OWF) would be connected to an existing HVDC line.

- In Figure 7-1Figure 7-1 (b), the hybrid interconnection results by building an offshore HVDC connection between two OWFs, each previously connected to its own area.
- In Figure 7-1(c), an artificial island is used as a hub to collect the power of several OWFs. Then this power is brought onshore through several HVDC links. This hub concept has been the subject of several European projects, such as the North Sea Wind Power Hub project (North Sea Wind Power Hub project, n.d.).

In the first two cases, the hybrid connection consists of a single HVDC network to which all OWFs and AC areas are connected. However, the technology used in the hub of the third case is still an open question. In the case of a DC hub, there is a single HVDC network between the different AC areas (as in the first two cases). On the other hand, in the case of an AC hub, all AC areas are connected to the AC island through point-to-point HVDC links. An illustrative example is provided in Figure 7-2.

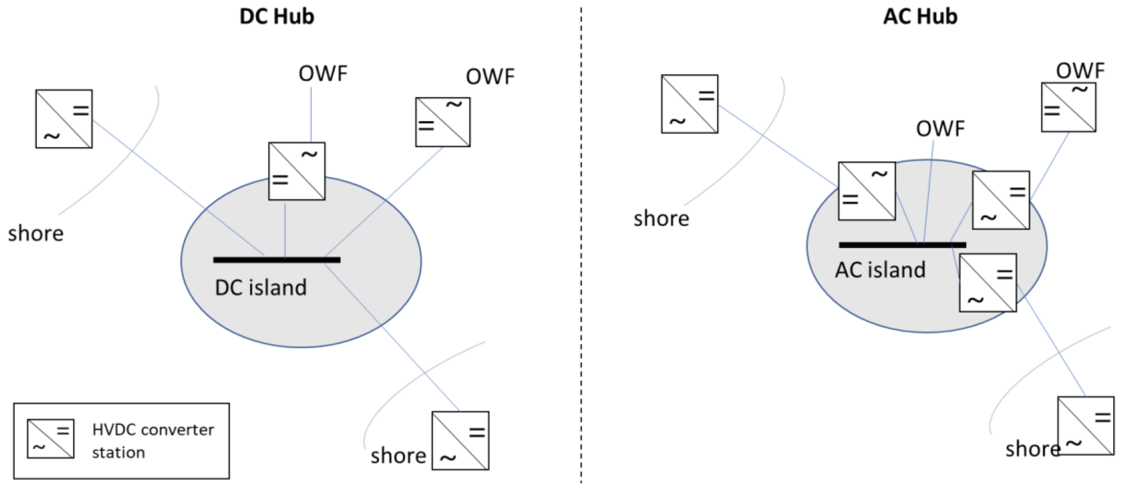

Figure 7-2: AC and DC hub examples

Regardless of the complexity of the topology, a common trait is the interconnection of two or more areas, operated by different Transmission System Operators (TSO), each with its own specifications and grid code requirements. Each topology consists of several elements, which are listed hereafter. The definitions are based on the ones of the European HVDC network code in (European Commission, 2016).

- HVDC system: an electrical power system which transfers energy in the form of HVDC current between two or more AC buses and comprises at least two HVDC converter stations with DC transmission lines or cables between the HVDC converter stations. For example, the DC hub of Figure 7-2 constitutes an HVDC system[1].
- HVDC converter station: part of an HVDC system which consists of one or more HVDC converter units installed in a single location together with buildings,

[1] The definition of the European HVDC network code does not cover the case of the AC hub due to the intervention of the AC island. Nevertheless, the individual HVDC point-to-point links connected to the island will be strongly dependent on each other. Hereafter, the AC hub case will be also considered as part of a single HVDC system

reactors, filters, reactive power devices, control, monitoring, protective, measuring and auxiliary equipment. In the attached questionnaire, it is proposed to use the wording onshore HVDC converter station (to avoid confusion with remote-end converter station).

- Remote-end HVDC converter: an HVDC converter station usually connected to an offshore platform or island. For example, in Figure 7-2 all HVDC converters connected to the AC island and OWFs are considered remote-end HVDC converters[2].
- DC-connected Power Park Module (PPM): a power park module that is connected via one or more HVDC interface points to one or more HVDC system. The OWFs of Figure 7-2 are DC-PPMs.

In order to **facilitate** the development of these hybrid assets, it is important to put in place a **set of technical requirements or guidelines** that needs to be met by each electrical component. That will allow the various manufacturers to select/develop the right piece of equipment compliant to these requirements, while **ensuring interoperability** between them. In the meantime, it will be possible for investors to better determine the price of a project and therefore **reduce risks**.

The final objective of the study is to propose a set of common guidelines that will be presented during a workshop to the relevant industry players.

<u>Purpose and structure of the questionnaire</u>

With this questionnaire Tractebel invites the North Sea TSOs to provide a key contribution to this project. The first objective of the questionnaire is to assess the level of convergence between member states for the relevant types of HVDC connection and power-generating modules. The second objective is to assess the gaps between the existing regulations and the technical requirements/guidelines needed to enable the construction of hybrid assets.

The questionnaire is structured in two parts as follows:

- Part A concerns the technical requirements already present in the current European network codes (European Commission, 2016). The aim of this part is to detect national variations/deviations from the existing European network codes, as well as between the national grid codes, that could prevent or slow down the development of future hybrid projects.
- Part B focuses on additional technical requirements that are expected to become part of a set of common guidelines for offshore HVDC connections. The necessity for these additional requirements emanates from the increased complexity expected to be introduced to HVDC systems with the development of hybrid projects. The aim of this second part of the questionnaire is to evaluate the gaps between the current regulation and guidelines proposed by accredited international organizations such as CENELEC (CENELEC, 2020) or CIGRE.

[2] This may give rise to topologies with only remote-end HVDC converters, e.g. a point-to-point link between an OWF and an AC island. In such cases, an adjustment of the remote-end HVDC converter definition might be required.

In order to facilitate the TSOs, this questionnaire has been pre-filled (where possible) based on information publicly available. The main sources include the monitoring documents published in (ENTSO-e, Monitoring report, n.d.).

The main findings of this questionnaire along with the additional proposed requirements will be presented at a workshop. This will be organized by Tractebel at the final stages of the project and it is expected that the European Commission, the relevant TSOs as well as HVDC systems vendors will participate in order to discuss and provide feedback on the findings.

Part A – Questionnaire on European network code requirements

The requested information in this part concerns the justification of the TSO for its requirement proposal or for the derogation from the European network codes.

It is important to mention that some differences will always remain between the TSOs as far as the connection of HVDC systems onshore is concerned (different voltage/frequency operating ranges, different system characteristics, etc.). Nevertheless, with the foreseen extension to more complex offshore topologies (hybrid connections, multi-terminal DC grids) these differences could raise operational issues. In addition, a misalignment at an offshore level (DC PPMs and remote-end HVDC systems) can raise compliance problems following the development of hybrid projects, possibly impeding such extensions.

Understanding the reasons behind the different proposals of the TSOs (at an onshore and offshore level) is crucial in order to assess the extent to which a set of common guidelines can be devised.

This document is accompanied by an Excel file. The latter includes a table with a non-exhaustive set of requirements specified in the European regulation related to HVDC systems, DC Power Park Modules (PPM) and remote-end HVDC systems based on (European Commission, 2016) and (European Commission, 2016), and the proposals made by the relevant TSOs according to (ENTSO-e, Monitoring report, n.d.). The main focus is on the articles of the HVDC network code, where most blocking points, if any, may be detected. Nevertheless, particular articles from the RfG network code have been also included due to their direct relation with the DC-PPMs. The requirements listed in the Excel file are, from the point of view of the Client, articles that might have to be adapted. The questionnaire also includes additional clarifications or complementary information identified by Tractebel after examining any relevant and publicly available TSO documents, included as references in the Excel file. Furthermore, some articles have been identified as especially important for the development of hybrid interconnections. The reason for each one is also included in the Excel file.

Tractebel asks each TSO to provide a justification for its proposal at specific articles of the European network codes. A justification is required only at the articles where a question has been expressed. A screenshot of the questionnaire can be seen in Figure 7-3 Readme tab is also included in the file to facilitate its completion.

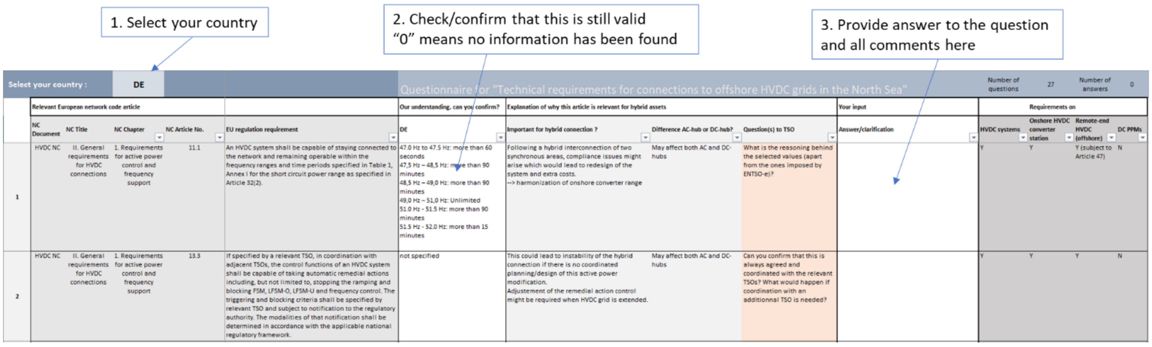

Figure 7-3: Screenshot of the questionnaire Part A

In addition to the questions listed in the Excel file for specific articles of the EU regulations, Tractebel has also identified the following high-level open questions, to which each TSO is invited to respond:

In several articles, reference to the "relevant TSO" is made. In your opinion, who will be the relevant TSO for the following components of a hybrid asset?

a) Onshore HVDC converter station
....

b) Offshore HVDC converter station connected to a DC bus/hub
....
...

c) Offshore HVDC converter station connected to an AC hub
....
...

d) DC-PPM connected to a DC bus/hub (via an offshore HVDC converter station)
....
...

e) DC-PPM connected to an AC hub
....
...

f) AC hub
....

...

Who would be the HVDC system owner following an extension to a hybrid connection?

....
...

Would you recommend a re-definition of the "HVDC system" as discussed in this document to take into account AC hubs?

....
....

7.2. Part A – Questions and TSO answers

The questions of Part A and the answers provided by the TSOs are given in Table 7-1 (first part of answers) and Table 7-2 (second part of answers). The answers to the high-level questions of Part A are given in Table 7-3.

NC Document	NC Article No.	EU regulation requirement	Question(s) to TSO	Answer BE-Elia	Answer DK-Energinet	Answer DE-Amprion	Answer DE-Tennet
HVDC NC	11.1	An HVDC system shall be capable of staying connected to the network and remaining operable within the frequency ranges and time periods specified in Table 1, Annex I for the short circuit power range as specified in Article 32(2).	What is the reasoning behind the selected values (apart from the ones imposed by the NC)?	In Elia's opinions, the HVDC converter needs to stay online even when all (other) running machines have already tripped.	In order to coordinate with RfG. HVDC NC is taken into consideration the interconnection of two synchroneous areas. Also the Danish implementation sets identical requirements on the CE and the nordic system.	System needs and relevant studies are accomplished by the relevant TSO. Also the NC emergency and restoration provides guidelines for the CE SA.	System needs and relevant studies made by the relevant TSO. Also the emergency and restoration network code provides such guidelines for the CE synchronous area.
HVDC NC	13.3	If specified by a relevant TSO, in coordination with adjacent TSOs, the control functions of an HVDC system shall be capable of taking automatic remedial actions including, but not limited to, stopping the ramping and blocking FSM, LFSM-O, LFSM-U and frequency control. The triggering and blocking criteria shall be specified by relevant TSO and subject to notification to the regulatory authority. The modalities of that notification shall be determined in accordance with the applicable national regulatory framework.	Can you confirm that this is always agreed and coordinated with the relevant TSOs? What would happen if coordination with an additionnal TSO is needed?	Yes, this common agreement is, for the time being always needed. There's too little knowledge and operational experience worldwide as of yet, to ascertain safe operation of the AC under all situations considering injection of HVDC converters. So far, Elia operates the Belgian side of the NEMO only for 1 1/2 year without severe incidents to assess the overall system behaviour under extreme conditions.	Yes- Further coordination with additonal offshore TSO would be needed	The triggering criteria shall be specified by the relevant transmission system operator in agreement with neighbouring transmission system operators. This can be coordinated by the relevant TSOs in future hybrid structures. Moreover, a future regulation covering AC or DC hubs could define explicitely such legal frame.	Yes it is confirmed. The triggering criteria shall be specified by the relevant transmission system operator in agreement with neighbouring transmission system operators.

HVDC NC	15 (Annex II.A)	Requirements applying to frequency sensitive mode, limited frequency sensitive mode overfrequency and limited frequency sensitive mode underfrequency shall be as set out in Annex II.FSM: - Frequency response deadband: 0-±500 mHz - Droop s1 (upward regulation): Minimum 0,1 % - Droop s2 (downward regulation): Minimum 0,1 % - Frequency response insensitivity: Maximum 30 mHz - Maximum admissible initial delay t1: 0,5 seconds - Maximum admissible time for full activation t2, unless longer activation times are specified by the relevant TSO: 30 seconds	In which cases would this requirement be absolutely necessary?	The TSO reserves the right, for safe operation when the amount of HVDC injections would rise significatly, to alter the control regimes in order to ensure the safe operation of the AC grid. The active power injection might then be proportionally controlled like regulal running machines.	Perhaps not absolutely necessary. But in case of decoupled AC systems on the onshore grid connection (e.g. nordic and CE)	This requirement is needed in order to serve the defined by the relevant TSO system needs (frequency stability). Please refer to NC Emergency and Restoration for further guidance.	The requirement is needed in order to serve the defined by the relevant TSO system needs (frequency stability). NC Emergency and restoration provides guidelines.
HVDC NC	17.1 and 17.2	1. An HVDC system shall be configured in such a way that its loss of active power injection in a synchronous area shall be limited to a value specified by the relevant TSOs for their respective load frequency control area, based on the HVDC system's impact on the power system. 2.Where an HVDC system connects two or more control areas, the relevant TSOs shall consult each other in order to set a coordinated value of the maximum loss of active power injection as referred to in paragraph 1, taking into account common mode failures.	How is the maximum loss of active power determined? Which contingencies have to be considered for designing and configuring the HVDC system (e.g. N-1, N-1 + stuck breaker, etc.)?	The maximum loss of the active power shall be mutually agreed upon between all relevant parties and is based on the dynamic security analysis method. Considering grid contingencies: this is fully dependent of the connected TSO's substations and local grid. Injecting on grid antennae reacts substantially diffently that on major substations.	Today defined as largest unit in the system. N-2 with prerequisite of unavailability of an AC interconnector to neighboring country. Breaker faillure is not considered.	HVDC systems shall be configured such as to limit the loss of the active power they exchange with the synchronous area to a value specified by relevant transmission system operators for their respective frequency control area. Where HVDC systems connect two or more control areas, the relevant transmission system operators shall consult each other in order to set a coordinated value of the maximum permissible loss of exchanged active power.	The maximum loss of power is defined based on the ‘frequency restoration reserves’ which reflects the active power reserves available to restore system frequency to the nominal frequency and, for a synchronous area consisting of more than one LFC area, to restore power balance to the scheduled value; Usually the loss of HVDC system as N-1 is considered. Additional information could be found on system operation guidelines.

HVDC NC	25.1	The relevant TSO shall specify, while respecting Article 18, a voltage-against time profile as set out in Annex V and having regard to the voltage-against-time-profile specified for power park modules according to Regulation (EU) 2016/631. This profile shall apply at connection points for fault conditions, under which the HVDC converter station shall be capable of staying connected to the network and continuing stable operation after the power system has recovered following fault clearance. The voltage-against-time-profile shall express a lower limit of the actual course of the phase-to-phase voltages on the network voltage level at the connection point during a symmetrical fault, as a function of time before, during and after the fault. Any ride through period beyond trec2 shall be specified by the relevant TSO consistent with Article 18.	Would you consider to harmonize the voltage-against-time-profile for hydrid assets?	When this proves useful and would not endanger future development opportunities, then yes. The question however is misleading: the statement has been clearly developed for HVDC connections to AC grid, whereas the question also implies direct DC connections to DC hubs. For he latter, little operations experience is available to draw conclusions and already harmonise characteristics.	Yes.	The voltage against time FRT profiles are defined based on the relevant system needs by the relevant TSO and are defined from dynamic/transient studies performed by the relevant TSOs. In a future HVDC grid or hybrid asset, if two or more relevant TSOs are involved, the requirements shall be harmonised on DC side. There is no need to harmonise FRT envelopes (at the onshore AC terminals) as the ac control areas have different system needs.	The voltage against time FRT profiles are defined based on the relevant system needs by the relevant TSO and are defined from dynamic/transient studies performed by the relevant TSOs. We do not see the need to harmonise FRT envelopes (at the onshore AC terminals) as the ac control areas have different system needs. In a future HVDC grid or hybrid asset, if two or more relevant TSOs are involved, the requirements shall be harmonised on DC side (choppers design, over & under voltage DC FRT envelopes).
HVDC NC	26	The relevant TSO shall specify the magnitude and time profile of active power recovery that the HVDC system shall be capable of providing, in accordance with Article 25.	On what analysis will be the selection of the profile be based?	Restrictions for the ramp-up rate could be forced as a result of electromagnetic and electromechanical simulations in common agreement with the DC system owner. Too fast ramping might cause recollapse of the AC system.	System stability studies. Such studies will include onshore stability studies. HVDC vendor considers normally both EMT and RMS-type studies in the design of the interconnector.Energinet nowadays employs (primarily) RMS-type studies. We are in the process of including EMT-type studies. This is critical e.g. to evaluate sustainable oscillations. A hybrid HVDC interconnecter in the Danish network would represent a "large"/critical unit. Therefore onshore performance of the interconnector is of high importance.	It is indeed acknowledged that the post-fault active power recovery could affect the AC-DC system dynamics. Slower active power ramping for onshore converters is not specified unless it is needed. The analysis is based on large scale dynamic simulations of the control area.	It is indeed acknowledged that the post-fault active power recovery could affect the AC-DC system dynamics. Slower active power ramping for onshore converters is not specified unless it is needed. The analysis is based on large scale dynamic simulations of the control area.

HVDC NC	29.7	The relevant TSO may specify transient levels of performance associated with events for the individual HVDC system or collectively across commonly impacted HVDC systems. This specification may be provided to protect the integrity of both TSO equipment and that of grid users in a manner consistent with its national code.	What aspects could constitute the minimum set of transient performance levels? What is the current practice for traditional point-to-point HVDC systems?	HVDC converters might 10 to 100 times faster than traditional converters. Reduced ramp rates, longer dead times, coordinated ramp-up might be in order. Due to the limited number of traditional HVDC converter, they are deemed to stay in service as long as possible. Their impact on the AC grid is still relatively limited, which might not be the case when many more converters, together with a diminishing number of traditional generation, are to come. Most likely, novel gird operation strategies need to be applied by the TSO.	Operational liminations like N-2 etc. Maturity of the technology (e.g. no generally adapted method for assessing multi-infeed interaction for VSC systems etc.) Need to ensure robust system for next 20-40 years. Site specific grid connection conditions makes it difficult employ coordinated requirements.	In point-to-point systems, special attention is given to transient performance levels on the DC-side of HVDC systems, mainly to ensure compatibility between converters' behaviour and transmission lines (e.g. cables). This refers mainy to transient overvoltages, but also transient currents that determine the design of the cables. Aspects of interest are switching/lightning impulse events and excess energy dissipating moments by the HVDC system. Also blocking of the offshore HVDC converter station for a couple of cycles is under the scope of such transient performance. Transient performance becomes even more crucial for MTDC systems where several converters and transmission lines have to be able to respect and withstand, respectively, a common DC voltage envelope Equal attention is given, at different engineering stages,	In point-to-point systems, special attention is given to transient performance levels on the DC-side of HVDC systems, mainly to ensure compatibility between converters' behaviour and transmission lines (e.g. cables). This refers mainy to transient overvoltages, but also transient currents that determine the design of the cables. Aspects of interest are switching/lightning impulse events and excess energy dissipating moments by the HVDC system. Also blocking of the offshore HVDC converter station for a couple of cycles is under the scope of such transient performance. Transient performance becomes even more crucial for MTDC systems where several converters and transmission lines have to be able to respect and withstand, respectively, a common DC voltage envelope Equal attention is given, at different engineering stages, at transient voltage stability, as well as harmonic stability.

						at transient voltage stability, as well as harmonic stability.	
HVDC NC	30	The HVDC system shall be capable of contributing to the damping of power oscillations in connected AC networks. The control system of the HVDC system shall not reduce the damping of power oscillations. The relevant TSO shall specify a frequency range of oscillations that the control scheme shall positively damp and the network conditions when this occurs, at least accounting for any dynamic stability assessment studies undertaken by TSOs to identify the stability limits and potential stability problems in their transmission systems. The selection of the control parameter settings shall be agreed between the relevant TSO and the HVDC system owner.	What would be the acceptable level of variability induced by a hybrid HVDC connection to your system due to oscillation damping?What is the current practice for traditional point-to-point HVDC systems?	Elia has, to my knowlegde, only operational experience with constant power injection, which is for the time being still acceptable given the predominant injection of traditional generation. Again, drastic change in the current landscape might force the TSO to adopt novel operation strategies with higher control implications for injectiong HVDC converters. The roder of magnitude for the damping capabilities is yet to be determined.	We do not use POD on our HVDC interconnectors. Functionality is required so that function can be enabled.The hybrid HVDC should include solutions to cope with these oscilations.Site specific studies should be carried out to design and activate when needed.	Unless required otherwise by the relevant transmission system operator, the control system for power oscillation damping (POD) shall be capable of actively damping power oscillations within the range of 0,1 Hz to 2,0 Hz by modulating the active power and/or reactive power. Up to date no HVDC links connecting PPMs are using this function. In a future scheme, if a hybrid HVDC scheme or DC grid connects various control areas or synchronous areas, we believe that a certain level of harmonisation should be achieved by setting up DC terminal requirements. On such DC terminal requirements, one may specifiy the acceptable level of DC voltage/power variations that could be accepted from various control areas connected to such DC grid.	Unless required otherwise by the relevant transmission system operator, the control system for power oscillation damping (POD) shall be capable of actively damping power oscillations within the range of 0,1 Hz to 2,0 Hz by modulating the active power and/or reactive power. Up to date no HVDC links connecting PPMs are using this function in TenneT control zone (hence we have not defined such variability). In a future scheme, if a hybrid HVDC scheme or DC grid connects various control areas or synchronous areas, we believe that a certain level of harmonisation should be achieved by setting up DC terminal requirements. On such DC terminal requirements, one may specifiy the acceptable level of DC voltage/power variations that could be accepted from various control areas connected to such DC grid.

HVDC NC	33.1	The HVDC system shall be capable of finding stable operation points with a minimum change in active power flow and voltage level, during and after any planned or unplanned change in the HVDC system or AC network to which it is connected. The relevant TSO shall specify the changes in the system conditions for which the HVDC systems shall remain in stable operation.	What would you consider as planned or unplanned change in the HVDC system? Only change in system conditions or also loss of equipment (including communication failure)? What is an acceptable maximum variation of active power for these changes in system conditions?	This question is for us and fot the time being topology specific and to be determined in the earliest possible stages of actual investment projects.	Loss of equipment + communication unless the system can operate without. Today, limit of max loss is equal largest generating unit in the Danish system. For Hybrid HVDC such requirement potentially needs to be reconsidered.	The changes to the network conditions during which the HVDC system shall maintain stable operation include, as a basic requirement, the following: – communication failure between the network control system and/or HVDC converter stations of an HVDC system; – reconfiguration of the HVDC system and of the AC system (planned and unplanned changes to the network topology); – changes to the load flow conditions; – control mode switch-over; – failure of external optimising and control functions.	The changes to the network conditions during which the HVDC system shall maintain stable operation include, as a basic requirement, the following: – communication failure between the network control system and/or HVDC converter stations of an HVDC system; – reconfiguration of the HVDC system and of the AC system (planned and unplanned changes to the network topology); – changes to the load flow conditions; – control mode switch-over; – failure of external optimising and control functions.
HVDC NC	33.2	The HVDC system owner shall ensure that the tripping or disconnection of an HVDC converter station, as part of any multi-terminal or embedded HVDC system, does not result in transients at the connection point beyond the limit specified by the relevant TSO.	This requirements focus on the impact on the AC-side. Would you consider having similar requirements on the DC-side?	Correct.	Yes- Even more critical with low impedance on DC side compared to AC system.	Yes, we fully suppor the development of DC terminal requirements in future offshore grid codes, especially if considering DC grids.	Yes, we fully suppor the development of DC terminal requirements in future offshore grid codes, especially if considering DC grids.

HVDC NC	34.1	The relevant system operator shall specify, in coordination with the relevant TSO, the schemes and settings necessary to protect the network taking into account the characteristics of the HVDC system. Protection schemes relevant for the HVDC system and the network, and settings relevant for the HVDC system, shall be coordinated and agreed between the relevant system operator, the relevant TSO and the HVDC system owner. The protection schemes and settings for internal electrical faults shall be designed so as not to jeopardise the performance of the HVDC system in accordance with this Regulation.	Are there specific technical requirements on DC fault clearing time (base and back-up)? Or on the protection strategy (level of selectivity)?	Elia has yet to build operational experience on DC protection systems. However, it has already the task to verify that the proposed protection systems have a sound overall scheme and parameter strategy and coordination for any new DC systems desiring to connect to its systems.	Not for interconnectors. If fault detected the HVDC system becomes unavailable.	Subject to agreement with the relevant transmission system operator, the relevant system operator shall specify the schemes necessary to protect the network taking into account the characteristics of the HVDC system. Protection schemes relevant to the HVDC system and the network relevant to the HVDC system shall be coordinated and agreed between the relevant system operator, the relevant transmission system operator and the connection owner.	No there are not such technical requirements on the DC fault clearing time. No real project experrience exist so far with regard to multi-terminal (MTDC) HVDC grids. We support the view that in a MTDC grid the protection schemes shall support full selectivity and ensure minimum loss of transmitted to the control areas active power.
HVDC NC	36.1	The parameters of the different control modes and the protection settings of the HVDC system shall be able to be changed in the HVDC converter station, if required by the relevant system operator or the relevant TSO, and in accordance with paragraph 3.	From your point of view, this article refers to which control modes? Do you have a practical experience where this was required?	Classic AC interaction is tested and understood, the DC system interaction operational experience is still to be build. This article is written to be future proof. The safety of all equipment and systems is of primordial importance, this might include fluent switching between control modes.	Outer loops, like active and reactive power control.Weak grid activation (case to case)	This article refers to general control modes with focus on parameters and settings affecting the AC connection point. Practical experience from multi-terminal projects indeed are designed with DC voltage control principles. However, those function are not required due to any grid code requirement so far.	Not defined in TCR HVDC 10.1.26. No experience is avaiable to hybrid systems (besides some planning studies).

HVDC NC	36.3	The control modes and associated setpoints of the HVDC system shall be capable of being changed remotely, as specified by the relevant system operator, in coordination with the relevant TSO.	Are the control modes site-specific or well-defined?	At this time, we deem them, as written, to be site specific. It might be so that taking future experience into account, this opinion might change.	Yes and no. Energiet specifies parameters for a new interconnector.	The majority of control modes are determined in the grid code, therefore they are not site or TSO specific. All of them are tested off-site as part of the compliance demonstration procedure. However, the operating control modes depend on the site characteristics.	The majority of control modes are determined in the connection codes. All of them are tested off-site as part of the compliance demonstration procedure. However, the operating control modes depend on the site characteristics.
HVDC NC	54.1	The relevant system operator in coordination with the relevant TSO may specify that an HVDC system owner deliver simulation models which properly reflect the behaviour of the HVDC system in both steady-state, dynamic simulations (fundamental frequency component) and in electromagnetic transient simulations. The format in which models shall be provided and the provision of documentation of models structure and block diagrams shall be specified by the relevant system operator in coordination with the relevant TSO.	What are the minimum model requirements at all cases? E.g. static, RMS, EMT and real-time replica?	To be agreed upon with each concrete investment project. Elia is doing ongoing research in this field as well and is acquiring progressing knowledge in this field and might miss research opportunities by fixing standards to quickly.	See Annex B for HVDC grid codes.RfG, appedix 1.b.We require the mentioned minimum electrical simulation models including RMT and EMT. RealTime replica not requested.	We receive from all projects RMS and EMT models for time domain simulatioins. Moreover, we perform frequency domain impedance based analysis based on Nyiquist criterion for the converter stations in order to detect potential control interactions risks due to varying grid conditions. Model quality criteria is not yet defined in the NCs.	There are various stages of studies performed which require different models. For initial planning and network development studies, standard static models are used. For dynamic RMS type planning studies, before commissioning, generic models are used. Later during commissioning, we receive from all HVDC projects RMS and EMT models for time domain simulatioins. Moreover, for some cases we perform frequency domain impedance based analysis (based on Nyiquist criterion for the converter stations, onshore and offshore) in order to detect potential control interactions risks due to varying grid conditions. Please note that model quality criteria is not yet defined in the NCs neither in the national implementations.

HVDC NC	54.4	An HVDC system owner shall submit HVDC system recordings to the relevant system operator or relevant TSO if requested in order to compare the response of the models with these recordings.	Would you consider sharing recordings with TSOs connected to the same hybrid asset (while respecting article 10 on confidentiality)?	Only when proven relevant to the research. To be agreed upon case by case.	Yes. Energinet finds this essential. Normally, for our system we can share recordings at the grid connection without restriction-	Yes, we migh consider sharing recordings if they support art. 54 of NC HVDC, especially if a certain criteria on model quality exists	Yes, we might consider sharing recordings if they support art. 54 of NC HVDC, especially if a certain criteria on model quality exists. Moreover the update of the models during projects lifecycle shall be supported here, especially refereing to NC HVDC Art 70.
HVDC NC	51.1	With regard to instrumentation for the operation, each HVDC converter unit of an HVDC system shall be equipped with an automatic controller capable of receiving instructions from the relevant system operator and from the relevant TSO. This automatic controller shall be capable of operating the HVDC converter units of the HVDC system in a coordinated way. The relevant system operator shall specify the automatic controller hierarchy per HVDC converter unit.	Is there a standardized interface for this automatic controller?Can you shortly describe the hierarchy that you typically specify?	This point has to be discussed case by case. Up till now, Elia has experience with 2 SIEMENS HVDC PLUS converter of which 1 is a merchant link and another a fully TSO operated link. The technology, interface, control strategies will likely be changed and refined over the years. We deem it too soon to standardise these already.	No standardised interface exists except the proposal from ENTSO-E RDIC ENTSO-E "Standardized control interface for HVDC SIL/HIL conformity tests" - published April 22, 2020.	There is a documement with title: ENTSO-E Standardized control interface for HVDC SIL/HIL conformity tests. An hierarchy is provided there.	There is a documement with title: ENTSO-E Standardized control interface for HVDC SIL/HIL conformity tests. An hierarchy is provided there. TenneT follows this approach.
HVDC NC	39,1b	1.With regards to frequency response: (b) DC-connected power park modules connected via HVDC systems which connect with more than one control area shall be capable of delivering coordinated frequency control as specified by the relevant TSO.	Would you consider the frequency response at the DC PPM interface or at the onshore HVDC converter interface?	Depending on the ownership of the individual systems, but clearly the end result would be supporting the AC grid.	onshore point of coupling	All capabilties for the frequency response shall be requested at the onshore converter stations based on the relevant system needs and coordinated with the PPMs. Harmonisation shall be achieved via future DC grid requirements.	All capabilties for the frequency response shall be requested at the onshore converter stations based on the relevant system needs of the control area and shall be coordinated with the PPMs. Harmonisation shall be achieved via future DC grid requirements for hybrid assets.

HVDC NC	39.2	2.With regard to frequency ranges and response: (a) a DC-connected power park module shall be capable of staying connected to the remote-end HVDC converter station network and operating within the frequency ranges and time periods specified in Annex VI for the 50 Hz nominal system. Where a nominal frequency other than 50 Hz, or a frequency variable by design is used, subject to agreement with the relevant TSO, the applicable frequency ranges and time periods shall be specified by the relevant TSO taking into account specificities of the system and the requirements set out in Annex VI;	What is the reason to deviate from the European NC ranges defined in Annex VI of the HVDC NC?	Elia deems it better to prioritise HVDC converters over classic gereration regarding staying connected to the grid in severe conditions.	The ranges in Annex VI are adopted in the Danish implentation of the HVDC NC.	There is no deviation from the EU NC ranges. Where, subject to agreement with the relevant transmission system operator, a nominal frequency other than 50 Hz or a frequency variable by design is used, the relevant transmission system operator shall specify adequate frequency ranges and associated periods for the power generating plant in accordance with the provisions of Frequency ranges of HVDC Systems and under consideration of the system properties.	There is not deviation here. The ranges are equal, compare Table 6 of VDE-AR-N 4131 and Table 8 of HVDC NC!

HVDC NC	39.2	(c) while respecting the provisions of point (a) of paragraph 2, a DC-connected power park module shall be capable of automatic disconnection at specified frequencies, if specified by the relevant TSO. Terms and settings for automatic disconnection shall be agreed between the relevant TSO and the DC-connected power park module owner.	What is the reason to deviate from the European NC ranges defined in Annex VI of the HVDC NC?	Elia deems it better to prioritise HVDC converters over classic gereration regarding staying connected to the grid in severe conditions.	We do not consider deviation from the HVDC NC as it is part of connection agreement. Agreed coordination shall be made across the hybrid HVDC system.	There is no deviation from the EU NC ranges. Where, subject to agreement with the relevant transmission system operator, a nominal frequency other than 50 Hz or a frequency variable by design is used, the relevant transmission system operator shall specify adequate frequency ranges and associated periods for the power generating plant in accordance with the provisions of Frequency ranges of HVDC Systems and under consideration of the system properties.	There is no deviation from the EU NC ranges. Where, a nominal frequency other than 50 Hz or a frequency variable by design is used, the relevant transmission system operator shall specify adequate frequency ranges and associated periods for the power generating plant in accordance with the provisions of Frequency ranges of HVDC Systems and under consideration of the system properties.
HVDC NC	47.2	2.With regards to frequency response, the remote-end HVDC converter station owner and the DC-connected power park module owner shall agree on the technical modalities of the fast signal communication in accordance with Article 39(1). Where the relevant TSO requires, the HVDC system shall be capable of providing the network frequency at the connection point as a signal. For an HVDC system connecting a power park module the adjustment of active power frequency response shall be limited by the capability of the DC-connected power park modules.	What is the reasoning behind the selection of the ranges?	Elia deems it better to prioritise HVDC converters over classic gereration regarding staying connected to the grid in severe conditions.	Coordination is critical on the offshore hub.By stating site specific requirements it is the intention to allow for harmonization rather than stating DK specific requirements.	We do not believe that this would be an issue for compliance. The requirements reflect technical standards for communication systems.	Question is not understandable. In this requirement no ranges are mentioned.

HVDC NC	48(1)(a)	Minimum time periods for which a remote-end HVDC converter station shall be capable of operating for different voltages deviating from a reference 1 pu value without disconnecting from the network: ≤110 kV and < 300 kV 0,85 pu-0,90 pu: 60 minutes 0,90 pu-1,10 pu: Unlimited 1,10 pu-1,12 pu: Unlimited, unless specified otherwise by the relevant system operator, in coordination with the relevant TSO. 1,12 pu-1,15 pu: To be specified by the relevant system operator, in coordination with the relevant TSO. ≤300 kV and < 400 kV 0,85 pu-0,90 pu: 60 minutes 0,90 pu-1,05 pu: Unlimited 1,05 pu-1,15 pu: To be specified by the relevant system operator, in coordination with the relevant TSO. Various sub-ranges of voltage withstand capability may be specified.	What would the reason for the deviating from the proposed ranges?	Elia deems it better to prioritise HVDC converters over classic gereration regarding staying connected to the grid in severe conditions.	Sustained high voltage undesired. Coordination on the AC-hub is relevant.	There is no deviation from the EU NC ranges.	There is no deviation from the EU NC ranges.
RFG NC	13.2.(a)	With regard to the limited frequency sensitive mode — overfrequency (LFSM-O), the following shall apply, as determined by the relevant TSO for its control area in coordination with the TSOs of the same synchronous area to ensure minimal impacts on neighbouring areas: (a) the power-generating module shall be capable of activating the provision of active power frequency response according to figure 1 at a frequency threshold and droop settings specified by the relevant TSO;	Would you accept a derogation in case of a new hybrid connection to an AC hub?		Yes, coordination on the offshore hub is relevant.	Derogations are coordinated by and agreed with the regulator. For this reason derogations are subject to many other criteria like legal and cost benefit analysis. Usually derogations require further investigations.	Derogations are coordinated and agreed with the regulator and are subject to many other criteria, like legal and cost benefit analysis.

RFG NC	15.2.(a)	Type C power-generating modules shall fulfil the following requirements relating to frequency stability: (a) with regard to active power controllability and control range, the power-generating module control system shall be capable of adjusting an active power setpoint in line with instructions given to the power-generating facility owner by the relevant system operator or the relevant TSO. The relevant system operator or the relevant TSO shall establish the period within which the adjusted active power setpoint must be reached. The relevant TSO shall specify a tolerance (subject to the availability of the prime mover resource) applying to the new setpoint and the time within which it must be reached;	Would this also apply to DC-PPMs?If yes, would you accept a derogation in case of a hybrid connection?	For the time being, we are open to a constructive discussion on this point.	Yes, coordination on the offshore hub is relevant.	Derogations are coordinated by and agreed with the regulator. For this reason derogations are subject to many other criteria like legal and cost benefit analysis. Usually derogations require further investigations.	Yes this applies to DC connected PPMs. Derogations are coordinated and agreed with the regulator and are subject to many other criteria, like legal and cost benefit analysis for example.
RFG NC	15.2.(c)(i)	In addition to Article 13(2), the following requirements shall apply to type C power-generating modules with regard to limited frequency sensitive mode — underfrequency (LFSM-U): (i) the power-generating module shall be capable of activating the provision of active power frequency response at a frequency threshold and with a droop specified by the relevant TSO in coordination with the TSOs of the same synchronous area as follows: — the frequency threshold specified by the TSO shall be between 49,8 Hz and 49,5 Hz inclusive, — the droop settings specified by the TSO shall be in the range 2-12 %.	Would you accept a derogation in case of a hybrid connection?	For the time being, we are open to a constructive discussion on this point.	Yes, potentially	Derogations are coordinated by and agreed with the regulator. For this reason derogations are subject to many other criteria like legal and cost benefit analysis. Usually derogations require further investigations.	It is relevant to check if RfG will apply to hybrid connections. As mentioned, derogations are coordinated and agreed with the regulator and are subject to additional criteria, like legal obligations and cost benefit analysis.

RFG NC	15.2.Figure 4	For PPM, Pref is the actual active power outpout at the moment the LFSM-U threshold is reached or the maximum capacity, as defined by the relevant TSO.	In case Pref<>Pact for PPM: What is the reason for the derogation from the European NC?	Please clarify your question.	Pref=Pmax is not a derogation from the European NC.	For this issue there is no derogation. Therefore our understanding of the German NC implementation differs from your interpretation.	The NC implementation is not understood correctly. Correction: PPM: Pref = Pact (instantaneously available active power)Pref>Pact: is not possible.Pact is similar to Pmax in consideration of: -the availability of primary energy sources; -the ambient conditions at the time of adjustment;-the operating conditions of the power generating plant, in particular, any limitations for operation near the agreed active connection power at underfrequencies and the corresponding impact of the ambient conditions; As mentioned, derogations are coordinated and agreed with the regulator and are subject to additional criteria, like legal obligations and cost benefit analysis.
RFG NC	16.3.a.(i)	power-generating modules shall be capable of staying connected to the network and continuing to operate stably after the power system has been disturbed by secured faults. That capability shall be in accordance with a voltage-against-time profile at the connection point for fault conditions specified by the relevant TSO.	Would these requirements also apply on DC-PPMs? If yes, would a derogation from the national code be accepted in case of a hybrid connection?	Correct. For the time being, we are open to a constructive discussion on this point.	Yes. Potentially, a common set of requirements is reasonable.	Derogations are coordinated by and agreed with the regulator. For this reason derogations are subject to many other criteria like cost benefit analysis. Usually derogations require further investigations.	1. Question: For DC-PPMs [VDE-AR-N 4131, Figure 15]: Uret: 0 Uclear: 0 Urec1: 0 Urec2: 0,85 tclear: 0,15 s trec1: 0,15 s trec2: 1,5 s trec3: 1,5 s 2. Question: As mentioned, derogations are coordinated and agreed with the regulator and are subject to additional criteria, like legal obligations and cost benefit analysis.

RFG NC	20.3.a	the relevant TSO shall specify the post-fault active power recovery that the power park module is capable:	would a derogation from the national code be accepted in case of a hybrid connection?	For the time being, we are open to a constructive discussion on this point.	Potentially. Also it should be taken into consideration where the gradient should be maintained. On the grid connection of the PPM or on the onshore HVDC POC.	Derogations are coordinated by and agreed with the regulator. For this reason derogations are subject to many other criteria like legal and cost benefit analysis. Usually derogations require further investigations.	It is important first to check if the current RfG would be applicable to future hybrid assets. This needs be clarified in order to set the frame of such derogation. Moreover, derogations are coordinated and agreed with the regulator and are subject to many other criteria, like cost benefit analysis etc.
RFG NC	15.6.c.(iii)	at the request of the relevant system operator or the relevant TSO, the power-generating facility owner shall provide simulation models which properly reflect the behaviour of the power-generating module in both steady- state and dynamic simulations (50 Hz component) or in electromagnetic transient simulations.	Parts of the models provided by manufacturers are encrypted for confidentiality reasons, how do you assess the perform the model verification process of these encrypted parts?	We're still in the process of developing a verification proces for those encrypted models. For the time being, the assessment is done by benchmarking the simulation model agains the Hardware-in-the-loop FAT tests of the convertor's C&P control cubicles.	Vendor/plant owner to perform functional tests like evaluation of LFSM-u/o and fault ride through that complies with the requirements. Detailed documentation, that can fully ensure correct user-handling of the model as well as high-level description of the encrypted parts. We require open-source RMS-type models and accept closed EMT-type models. Primary challenge with closed models model maintaining during e.g. software update	Standard interfaces in control blocks respect the intellectual property of vendors. We believe that source code is important to be part of the models in order to have accurate representations of the PPMs or HVDC system. Model quality criteria does not exist, yet, in CNCs. However, an new GC-ESC expert group is working on such content.	Model quality and model validation criteria does not exist, yet, in CNCs. However, a new GC-ESC expert group is working on such content. We believe that source code is important to be part of the models in order to have accurate and reproducible representations of the PPMs or HVDC system in grid connection studies. The later shall support also NC HVDC art. 29

Table 7-1 : Part A - Questions and TSO answers (Part 1/2)

NC Document	NC Article No.	EU regulation requirement	Question(s) to TSO	Answer NL-Tennet	Answer FR-RTE	Answer National Grid ESO	Answer SE-SVK
HVDC NC	11.1	An HVDC system shall be capable of staying connected to the network and remaining operable within the frequency ranges and time periods specified in Table 1, Annex I for the short circuit power range as specified in Article 32(2).	What is the reasoning behind the selected values (apart from the ones imposed by the NC)?	Values confirmed. However it is not clear to us why it would affect the DC hubs.	Code values OK, no need for different requirements	For Offshore there is no difference in the treatment between AC or DC Offhsore Connections. For HVDC Systems and Remote End HVDC Converter Stations the time range between 51.5-52Hz is 20 minutes	The HVDC system should be the last part that is disconnected. Therefore the requirements have been written to be at least as strict or stricter than the corresponding requirements specified in the RfG and DCC. Generally the national code should be adapted and updated to fit the needs of the society as well as the techincal development within the area while also taking into consideration the existing capabilities of the power system.
HVDC NC	13.3	If specified by a relevant TSO, in coordination with adjacent TSOs, the control functions of an HVDC system shall be capable of taking automatic remedial actions including, but not limited to, stopping the ramping and blocking FSM, LFSM-O, LFSM-U and frequency control. The triggering and blocking criteria shall be specified by relevant TSO and subject to notification to the regulatory authority. The modalities of that notification shall be determined in accordance with the applicable national regulatory framework.	Can you confirm that this is always agreed and coordinated with the relevant TSOs? What would happen if coordination with an additionnal TSO is needed?	1) Yes, that is the legal obligation from the code. 2) The coordination will be extended with the additional TSO.	In the French code, RTE requires FSM, LFSM, stop ramping and stop frequency control (=freeze function). Coordonation between TSO is essential, thus agreement between TSO/SO/owner is required (bilateral agreement or trilateral agrement if relevant).	This would be agreed on a site specific basis	Yes, Svk can confirm that this is agreed and coordinated between the relevant TSOs. A joint agreement would still be the objective even if there are more than two TSOs involved.

HVDC NC	15 (Annex II.A)	Requirements applying to frequency sensitive mode, limited frequency sensitive mode overfrequency and limited frequency sensitive mode underfrequency shall be as set out in Annex II. FSM: - Frequency response deadband: 0-±500 mHz - Droop s1 (upward regulation): Minimum 0,1 % - Droop s2 (downward regulation): Minimum 0,1 % - Frequency response insensitivity: Maximum 30 mHz - Maximum admissible initial delay t1: 0,5 seconds - Maximum admissible time for full activation t2, unless longer activation times are specified by the relevant TSO: 30 seconds	In which cases would this requirement be absolutely necessary?	FSM, LFSM-O and LFSM-U serve to stabilize frequency. For HVDC systems conecting generation, it is important that also that generation is able to participate in frequency control. For HVDC systems connecting different synchronous areas, agreements have to made about the amount of frequency support that is provided to the other SA. The principle of supporting the grid frequency should be kept due to large disturbances that may be occuring in the AC grids due to load rejection events, etc. Due to the changing generation mix and reducing inertia the importance of frequency control will only increase. Therefore, it is important to reserve such requirements for hybrid systems as well.	French code : no deadband, insenstitivity 10mHz, S1[3%-12%], S2 [3%,12%], t1<=0,5s, t2<=30s, s3>=0,1%. The code requirements apply for any case.	This capability would be required on all HVDC Systems. DC Connected Power Park Modules have to meet the same requirements as RfG but are not within the scope of this clause.	If studies show that the HVDC system could have a large impact on the frequency stability of the AC system.

HVDC NC	17.1 and 17.2	1. An HVDC system shall be configured in such a way that its loss of active power injection in a synchronous area shall be limited to a value specified by the relevant TSOs for their respective load frequency control area, based on the HVDC system's impact on the power system. 2.Where an HVDC system connects two or more control areas, the relevant TSOs shall consult each other in order to set a coordinated value of the maximum loss of active power injection as referred to in paragraph 1, taking into account common mode failures.	How is the maximum loss of active power determined? Which contingencies have to be considered for designing and configuring the HVDC system (e.g. N-1, N-1 + stuck breaker, etc.)?	Regulation prescribes that the volume of available FRR should be determined based on a deterministic analysis (largest imbalance that may result from an instantaneous change of active power) and a probabilistic analysis. At the moment, the highest volume from both analysis is leading and should be contracted by the respective Control Block. Determination of contingencies in hybrid systems should depend on the actual topology, modes of operation and its system ratings. Impact on the protection strategy depends on impact on the AC grid(s) that hybrid system connects to.	It is based on the loss of the bggest power plant in France (eg EPR= 1800MW). N-1 only is taken into account	The maximum active power loss is determined through the SQSS and in GB is set at 1800MW under the worst case. This has been determined through system studies and a cost benefit analysis. In GB the worst case contigency is N-2.	Maximum loss of power is not allowed to be larger than the largest N-1 contingency in the swedish system. We are not sure we fully understand the second question. When designing the HVDC system the supplier checks a lot of different contingencies that could occur within the HVDC converter stations.

HVDC NC	25.1	The relevant TSO shall specify, while respecting Article 18, a voltage-against time profile as set out in Annex V and having regard to the voltage-against-time-profile specified for power park modules according to Regulation (EU) 2016/631. This profile shall apply at connection points for fault conditions, under which the HVDC converter station shall be capable of staying connected to the network and continuing stable operation after the power system has recovered following fault clearance. The voltage-against-time-profile shall express a lower limit of the actual course of the phase-to-phase voltages on the network voltage level at the connection point during a symmetrical fault, as a function of time before, during and after the fault. Any ride through period beyond trec2 shall be specified by the relevant TSO consistent with Article 18.	Would you consider to harmonize the voltage-against-time-profile for hydrid assets?	The FRT profile applies to the AC connection in the synchronous area, and is related to the protection system in that area. Harmonizing the FRT profiles of different SA connections does not make sense. Harmonisation is not needed as long as proper coordination among the units of the hybrid system can be ensured during events that would trigger energy dissipating mechanisms.	Requirement from French code shall apply	They are both the same for AC and DC cases. DC Connected Power Park Modules also have to meet the same requirements.	The national requirement has been written to be at least as strict as the corresponding requirements in the RfG. Generally the national code should be adapted and updated to fit the needs of the society as well as the techincal development within the area while also taking into consideration the existing capabilities of the power system.
HVDC NC	26	The relevant TSO shall specify the magnitude and time profile of active power recovery that the HVDC system shall be capable of providing, in accordance with Article 25.	On what analysis will be the selection of the profile be based?	Agreement between the involved TSOs is needed.	Requirements of the French code shall apply, and thus the profile already defined. This is a stability issue and voltage quality.	In GB there is consitency between AC and DC and we also have the benefit of one Sycnchronous Area. Where there are issues between two TSO's in different Synchronous Areas they will need to be agreed on a bilateral basis	Mainly a frequency stability study of the synchronous areas that are affected by the exchange of active power. Generally the national code should be adapted and updated to fit the needs of the society as well as the techincal development within the area while also taking into consideration the existing capabilities of the power system.

HVDC NC	29.7	The relevant TSO may specify transient levels of performance associated with events for the individual HVDC system or collectively across commonly impacted HVDC systems. This specification may be provided to protect the integrity of both TSO equipment and that of grid users in a manner consistent with its national code.	What aspects could constitute the minimum set of transient performance levels? What is the current practice for traditional point-to-point HVDC systems?	In point-to-point systems, special attention is given to transient performance levels on the DC-side of HVDC systems, mainly to ensure compatibility between converters' behaviour and transmission lines (e.g. cables). This refers mainy to transient overvoltages, but also transient currents that determine the design of the cables. Aspects of interest are switching/lightning impulse events and excess energy dissipating moments by the HVDC system. Transient performance becomes even more crucial for MTDC systems where several converters and transmission lines have to be able to respect and withstand, respectively, a common DC voltage envelope Equal attention is given, at different engineering stages, at transient voltage stability, as well as harmonic stability.	to be further worked ; no specific requirement from now. Expert group is supposed to be launched at ENTSO-E level regarding EMT modelisation so it will mayde discuss topics linked to this issue	The transient levels of performance for Point ot Point HVDC are currently specifed in the Bilateral Agreement. See generic example https://www.nationalgrideso.com/document/33976/download We would expect to use the same aspects for hybrid solutions where we can but this would need to be discussed on a Bilateral basis.	We are not sure we understand the question.

HVDC NC	30	The HVDC system shall be capable of contributing to the damping of power oscillations in connected AC networks. The control system of the HVDC system shall not reduce the damping of power oscillations. The relevant TSO shall specify a frequency range of oscillations that the control scheme shall positively damp and the network conditions when this occurs, at least accounting for any dynamic stability assessment studies undertaken by TSOs to identify the stability limits and potential stability problems in their transmission systems. The selection of the control parameter settings shall be agreed between the relevant TSO and the HVDC system owner.	What would be the acceptable level of variability induced by a hybrid HVDC connection to your system due to oscillation damping? What is the current practice for traditional point-to-point HVDC systems?	In point-to-point HVDC systems, oscillation damping is hardly ever excercised due to the fact that the HVDC converter may not be effective due to its location, and because certain amount of power capacity needs to be reserved (and therefore removed from actual interconnected power levels) for being able to support such service. An approximate figure of up to 10% of rated power could be assumed for power oscillation damping, but this highly depends on the market design. Similar, but more complicated, market mechanisms would apply also for hybrid systems.	Same requirements as for HVDC system ; they are described in the French Code. As base case, it shall not lead to any oscillation.	The damping requirements for Point to Point HVDC are currently specifed in ECC.6.3.17.1.3 and the Bilateral Agreement. See generic example https://www.nationalgrideso.com/document/33976/download We would expect to use the same aspects for hybrid solutions where we can but this would need to be discussed on a Bilateral basis.	Answer to both questions is that it is site specific.

HVDC NC	33.1	The HVDC system shall be capable of finding stable operation points with a minimum change in active power flow and voltage level, during and after any planned or unplanned change in the HVDC system or AC network to which it is connected. The relevant TSO shall specify the changes in the system conditions for which the HVDC systems shall remain in stable operation.	What would you consider as planned or unplanned change in the HVDC system? Only change in system conditions or also loss of equipment (including communication failure)? What is an acceptable maximum variation of active power for these changes in system conditions?	All cases mentioned in column NL reflect the possible planned and unplanned changes in the HVDC system. Therefore, loss of equipment is also included. For loss of interstation communication, no change in active power transmission should be observed unless it coincided with power ramping periods. Other control modes may have to be blocked though, such as POD, FC, FRT, etc. Changes in control modes or point of control should have no, or negligible, impact to active power transmission. Failure of C&P system is not common anymore, due to redundancies reserved. However, in case it hapens it may even lead to complete shutdown. Changes in topology of the high-voltage grid (e.g. impedance changes) should not affect the active power transmission as long as the changes do not result in short-circuit levels that go beyond the minimum and maximum figures used for the design of the HVDC system. In such extreme	Planned and unplanned changes shall be considered. It shall include system conditions and loss of equipment.	A planned change would be a scheduled outage - eg for maintenance work. An unplanned outage would be due to a fault. The maximum acceptable variaiton of active power will vary dpending upon the fault and the equipment affected. In the case of communications faults, there may be a need to curtain the transfer but it depends on the fault. All of these issues are planned for in the planning and operaitonal timeframe.	A planned change is any change that is intentionally made. An unplanned change is any unintentional change in the HVDC system. The variation of active power should be as small as possible.

				cases, TSO's should make special provisions and one of them could be a runback scenario where active power gets immediately limited. Changes of net topology of HVDC system will have different impact to active power transmission depending on hybrid topology, system configuration (e.g. bipole), etc.			
HVDC NC	33.2	The HVDC system owner shall ensure that the tripping or disconnection of an HVDC converter station, as part of any multi-terminal or embedded HVDC system, does not result in transients at the connection point beyond the limit specified by the relevant TSO.	This requirements focus on the impact on the AC-side. Would you consider having similar requirements on the DC-side?	Definitely, it is very important.	Yes there shall be requirements, but exact content to be defined.	Yes where necessary and justified.	Generally the national code should be adapted and updated to fit the needs of the society as well as the techincal development within the area while also taking into consideration the existing capabilities of the power system.

HVDC NC	34.1	The relevant system operator shall specify, in coordination with the relevant TSO, the schemes and settings necessary to protect the network taking into account the characteristics of the HVDC system. Protection schemes relevant for the HVDC system and the network, and settings relevant for the HVDC system, shall be coordinated and agreed between the relevant system operator, the relevant TSO and the HVDC system owner. The protection schemes and settings for internal electrical faults shall be designed so as not to jeopardise the performance of the HVDC system in accordance with this Regulation.	Are there specific technical requirements on DC fault clearing time (base and back-up)? Or on the protection strategy (level of selectivity)?	The protection strategy (fault clearing time, backup protection, etc.) for hybrid systems should be determined based on the exact topology and the impact of major disturbances to the DC and AC-sides of the system.	We have functional requirements and a dedicated specification for protection.	This needs careful thought. The Grid Code specifies requirements for protection co-ordination. These rules are currentspecified mainly round HV AC equipment but some thought needs to be given to HVDC systems which require quite a different philosophy, particulalry in respect of the operation of DC breakers and how discrimination and co-ordination is managed. This is an area which requires further assessment.	These requirements are project specific. Currently we have no requirements for DC grids but we are following the development within the area.

HVDC NC	36.1	The parameters of the different control modes and the protection settings of the HVDC system shall be able to be changed in the HVDC converter station, if required by the relevant system operator or the relevant TSO, and in accordance with paragraph 3.	From your point of view, this article refers to which control modes? Do you have a practical experience where this was required?	Protection settings are often adjusted during on-site commissioning. The same may happen for control settings, especially when it is observed that grid characteristics are different than how the grid was represented during off-site DPT. One typical exmaple is harmonic damping controllers for offshore HVDC units. In general, this article refers to all control modes where it is possible for the operator to change the default settings within the given range which is reserved for every mode. Changing parameters of DC-side controller is typically not possible for operators.	This requirement is important for RTE and is used.	No not as far as I am aware. There may be some experience of this for the Caithness - Moray link but this would require input from the experts within this project. Offhsore HVDC Systems, in particular Hybrid HVAC/HVDC are still at an early stage of develpment in GB.	We want to be able to change control modes that affect the HVDC system behaviour and interaction with the AC system. parameters or control modes that directly impacts the safe operation of the HVDC system we do not want to change. Generally we don't change protection settings.
HVDC NC	36.3	The control modes and associated setpoints of the HVDC system shall be capable of being changed remotely, as specified by the relevant system operator, in coordination with the relevant TSO.	Are the control modes site-specific or well-defined?	The majority of control modes are determined in the grid code, therefore they are not site or TSO specific. All of them are tested off-site as part of the compliance demonstration procedure. However, the operating control modes depend on the site characteristics. For example, in a weak grid it is prefered to make use of AC voltage controller, instead of Q control.	Up to now, they are defined for each HVDC according to the need.	Site specific.	The control modes are site-specific

HVDC NC	54.1	The relevant system operator in coordination with the relevant TSO may specify that an HVDC system owner deliver simulation models which properly reflect the behaviour of the HVDC system in both steady-state, dynamic simulations (fundamental frequency component) and in electromagnetic transient simulations. The format in which models shall be provided and the provision of documentation of models structure and block diagrams shall be specified by the relevant system operator in coordination with the relevant TSO.	What are the minimum model requirements at all cases? E.g. static, RMS, EMT and real-time replica?	For the development of point-to-point systems, RMS and EMT balck box models are traditionally required. Real-time simulators may be asked in some cases for personnel training only, but this is not normal practice. For developing hybrid assets, it will become highly essential to obtain grey box delivered models for offline simulations. Real-time replicas may become needed in case the development of the hybrid system takes place in different periods of time.	The following models are required : phasor, EMT, replica	The mimium requirements are speicified in the Grid Code (Planning Code) and Bilateral Agreement which would extend to static, RMS (dynamic) and where required EMT. In addition and where required real-tme replica through an RTDS could be used through the National HVDC Centre though thsi would vary depenfing on the developers, partners and project.	The minimum requirements are RMS models in PSS/E format and EMT models in PSCAD format that fully represent the static and dynamic behaviour of the HVDC system and its control functions. The minimum requirements on models are being reviewed and in the future we will likely also require admittance and emission profiles, and possibly also real-time replicas.
HVDC NC	54.4	An HVDC system owner shall submit HVDC system recordings to the relevant system operator or relevant TSO if requested in order to compare the response of the models with these recordings.	Would you consider sharing recordings with TSOs connected to the same hybrid asset (while respecting article 10 on confidentiality)?	We expect this to be necessary, so yes.	to be discussed, depends on the subject	Yes where necessary and we are able to do so.	Yes, Svenska kraftnät would consider sharing recordings with TSOs connected to the same hybrid asset.

HVDC NC	51.1	With regard to instrumentation for the operation, each HVDC converter unit of an HVDC system shall be equipped with an automatic controller capable of receiving instructions from the relevant system operator and from the relevant TSO. This automatic controller shall be capable of operating the HVDC converter units of the HVDC system in a coordinated way. The relevant system operator shall specify the automatic controller hierarchy per HVDC converter unit.	Is there a standardized interface for this automatic controller? Can you shortly describe the hierarchy that you typically specify?	The automatic controller defines the priority of event-driven control functions and determines the type of response per function (e.g. temporary blocking, stop ongoing regulation, block until command is ackowledged by the otehr side, etc.). Similarly, the autoatic controller defines the priorities (or allows simultaneous operation) of control functions for normal (continuous) operation. For example, FRT mode has traditionally the highest priority, followed by special protection schemes and emergency controls. Acitve and reactive power control modes are usually with lowest priority. The priorities are usually set based on operational purpose of the asset and the market design in case of non-regulated operation.	A tool is used to send active power setpoints to HVDC. Not clear what you mean by hierarchy.	This would need to be achieved on a Bilateral Basis (generally through the connection agreement) depending upon the design and topology. We do have a standard (TS.3.24.90 - Protection and Control for HVDC Systems - available at:- https://www.nationalgrideso.com/document/33201/download	No, no standardized interface.

HVDC NC	39,1b	1.With regards to frequency response: (b) DC-connected power park modules connected via HVDC systems which connect with more than one control area shall be capable of delivering coordinated frequency control as specified by the relevant TSO.	Would you consider the frequency response at the DC PPM interface or at the onshore HVDC converter interface?	This highly depends on the regulation and the compensation scheme for DC PPM owner. On technical terms, as far as the onshore AC grid is concerned, response at the onshore HVDC converter interface would be sufficient.	Frequency shall be controlled on the AC side. We do not understand what you mean on DC side.	Both. The DC Power Park Module would need to have a frequency response capability and the HVDC Converter would need to have a frequency response capability. The HVDC link is only a power tranmission medium so the bulk of the work would need to be completed through the DC Connected Power Park Module. Co-ordiantion would however be required for all parties concerned.	To be considered.
HVDC NC	39.2	2.With regard to frequency ranges and response: (a) a DC-connected power park module shall be capable of staying connected to the remote-end HVDC converter station network and operating within the frequency ranges and time periods specified in Annex VI for the 50 Hz nominal system. Where a nominal frequency other than 50 Hz, or a frequency variable by design is used, subject to agreement with the relevant TSO, the applicable frequency ranges and time periods shall be specified by the relevant TSO taking into account specificities of the system and the requirements set out in Annex VI;	What is the reason to deviate from the European NC ranges defined in Annex VI of the HVDC NC?	There is no deviation from the EU NC ranges. The site specific requirements only applies in case of the nominal frequency is different than 50 HZ, as allowed by the EU grid code. Please note that Dutch grid code only specifies the items left for the national implementation. If an item is already specified explicity in the EU grid code, the Dutch grid code does not repeat it.	Not same as RfG, see values in French code.	None - They are consistent with RfG and Annex VI of the HVDC Code	To be considered.

HVDC NC	39.2	(c) while respecting the provisions of point (a) of paragraph 2, a DC-connected power park module shall be capable of automatic disconnection at specified frequencies, if specified by the relevant TSO. Terms and settings for automatic disconnection shall be agreed between the relevant TSO and the DC-connected power park module owner.	What is the reason to deviate from the European NC ranges defined in Annex VI of the HVDC NC?	There is no deviation from the EU NC ranges. The site specific requirements only applies in case of the nominal frequency is different than 50 HZ, as allowed by the EU grid code. Please note that Dutch grid code only specifies the items left for the national implementation. If an item is already specified explicity in the EU grid code, the Dutch grid code does not repeat it.	Not same as RfG, see values in French code.	None unless for a specific reason agreed with the TSO but this is very unusual.	Generally the national code should be adapted and updated to fit the needs of the society as well as the techincal development within the area while also taking into consideration the existing capabilities of the power system.
HVDC NC	47.2	2.With regards to frequency response, the remote-end HVDC converter station owner and the DC-connected power park module owner shall agree on the technical modalities of the fast signal communication in accordance with Article 39(1). Where the relevant TSO requires, the HVDC system shall be capable of providing the network frequency at the connection point as a signal. For an HVDC system connecting a power park module the adjustment of active power frequency response shall be limited by the capability of the DC-connected power park modules.	What is the reasoning behind the selection of the ranges?		RfG code	There needs to be consistency between the HVDC System and DC Connected Power Park Module. In GB the frequency response capability requirements between HVDC and HVAC and DC Connected Power Park Modules are consistent.	No ranges have been selected in the existing national code. Generally the national code should be adapted and updated to fit the needs of the society as well as the techincal development within the area while also taking into consideration the existing capabilities of the power system.

HVDC NC	48(1)(a)	Minimum time periods for which a remote-end HVDC converter station shall be capable of operating for different voltages deviating from a reference 1 pu value without disconnecting from the network: ≤110 kV and < 300 kV 0,85 pu-0,90 pu: 60 minutes 0,90 pu-1,10 pu: Unlimited 1,10 pu-1,12 pu: Unlimited, unless specified otherwise by the relevant system operator, in coordination with the relevant TSO. 1,12 pu-1,15 pu: To be specified by the relevant system operator, in coordination with the relevant TSO. ≤300 kV and < 400 kV 0,85 pu-0,90 pu: 60 minutes 0,90 pu-1,05 pu: Unlimited 1,05 pu-1,15 pu: To be specified by the relevant system operator, in coordination with the relevant TSO. Various sub-ranges of voltage withstand capability may be specified.	What would the reason for the deviating from the proposed ranges?	There is no deviation from the EU NC ranges. Please note that Dutch grid code only specifies the items left for the national implementation. If an item is already specified explicity in the EU grid code, the Dutch grid code does not repeat it.	RfG code + taking into account french constraints	None unless for a specific reason agreed with the TSO but this is very unusual.	Generally the national code should be adapted and updated to fit the needs of the society as well as the techincal development within the area while also taking into consideration the existing capabilities of the power system.

RFG NC	13.2.(a)	With regard to the limited frequency sensitive mode — overfrequency (LFSM-O), the following shall apply, as determined by the relevant TSO for its control area in coordination with the TSOs of the same synchronous area to ensure minimal impacts on neighbouring areas: (a) the power-generating module shall be capable of activating the provision of active power frequency response according to figure 1 at a frequency threshold and droop settings specified by the relevant TSO;	Would you accept a derogation in case of a new hybrid connection to an AC hub?	TenneT is not in a position to approve a derogation request as they are handled by the regulator. The frequency response is to the frequency in the Synchronous Area, not the frequency in the offshore AC grid, and the resulting active power response should be directed to the relevant onshore converter station. Alignment on the technical implementation amongst involved TSOs is necessary.	NC chapter/article number not relevant. Question thus to be clarified	We would expect a new hybrid connection to have the same requirements. In GB we are reluctant to using the dergation route especially for new plant. Where this is unavoidable, discussions would need to take place with all parties to understand the issues for non-compliance.	Generally the national code should be adapted and updated to fit the needs of the society as well as the techincal development within the area while also taking into consideration the existing capabilities of the power system.

RFG NC	15.2.(a)	Type C power-generating modules shall fulfil the following requirements relating to frequency stability: (a) with regard to active power controllability and control range, the power-generating module control system shall be capable of adjusting an active power setpoint in line with instructions given to the power-generating facility owner by the relevant system operator or the relevant TSO. The relevant system operator or the relevant TSO shall establish the period within which the adjusted active power setpoint must be reached. The relevant TSO shall specify a tolerance (subject to the availability of the prime mover resource) applying to the new setpoint and the time within which it must be reached;	Would this also apply to DC-PPMs? If yes, would you accept a derogation in case of a hybrid connection?	TenneT is not in a position to approve a derogation request as they are handled by the regulator. Alignment is needed amongst the involved TSOs on the specified parameters.	French code shall apply. A procedure is given to define if a deviation can be considered (see art. 64 RfG)	We would expect a new hybrid connection to have the same requirements. In GB we are reluctant to using the dergation route especially for new plant. Where this is unavoidable, discussions would need to take place with all parties to understand the issues for non-compliance. In general we would expect the DC PPM's to meet the requirements of the network code	Generally the national code should be adapted and updated to fit the needs of the society as well as the techincal development within the area while also taking into consideration the existing capabilities of the power system.

RFG NC	15.2.(c)(i)	In addition to Article 13(2), the following requirements shall apply to type C power-generating modules with regard to limited frequency sensitive mode — underfrequency (LFSM-U): (i) the power-generating module shall be capable of activating the provision of active power frequency response at a frequency threshold and with a droop specified by the relevant TSO in coordination with the TSOs of the same synchronous area as follows: — the frequency threshold specified by the TSO shall be between 49,8 Hz and 49,5 Hz inclusive, — the droop settings specified by the TSO shall be in the range 2-12 %.	Would you accept a derogation in case of a hybrid connection?	TenneT is not in a position to approve a derogation request as they are handled by the regulator. The frequency response is to the frequency in the Synchronous Area, not the frequency in the offshore AC grid, and the resulting active power response should be directed to the relevant onshore converter station. Alignment on the technical implementation amongst involved TSOs is necessary.	French code shall apply. A procedure is given to define if a deviation can be considered (see art. 64 RfG)	We would expect a new hybrid connection to have the same requirements. In GB we are reluctant to using the dergation route especially for new plant. Where this is unavoidable, discussions would need to take place with all parties to understand the issues for non-compliance. In general we would expect the DC PPM's to meet the requirements of the network code.	Generally the national code should be adapted and updated to fit the needs of the society as well as the techincal development within the area while also taking into consideration the existing capabilities of the power system.
RFG NC	15.2.Figure 4	For PPM, Pref is the actual active power outpout at the moment the LFSM-U threshold is reached or the maximum capacity, as defined by the relevant TSO.	In case Pref<>Pact for PPM: What is the reason for the derogation from the European NC?	There is no derogation, the parameters are defined in the refered Figure 4. Question is not understood.	Pref is not automatically equal to Pact in our notaional requirement	In GB we use Pmax to determine Pref. We would not look for a derogation for new plant.	There is no derogation from the european NC.

RFG NC	16.3.a.(i)	power-generating modules shall be capable of staying connected to the network and continuing to operate stably after the power system has been disturbed by secured faults. That capability shall be in accordance with a voltage-against-time profile at the connection point for fault conditions specified by the relevant TSO.	Would these requirements also apply on DC-PPMs? If yes, would a derogation from the national code be accepted in case of a hybrid connection?	The requirements also apply to DC-PPMs. Technically we support the idea of common requirements. Derogation requests are handled by the regulator.	French code shall apply.	Yes they are consistent. In GB we do not generally like derogations for new plant. If absolutely necessary we would need to understand why a derogation was necessary depending on the plant technology and topology.	It is to be considered. Generally the national code should be adapted and updated to fit the needs of the society as well as the techincal development within the area while also taking into consideration the existing capabilities of the power system.
RFG NC	20.3.a	the relevant TSO shall specify the post-fault active power recovery that the power park module is capable:	would a derogation from the national code be accepted in case of a hybrid connection?	TenneT is not in a position to approve a derogation request as they are handled by the regulator.	French code shall apply.	In GB we do not generally like derogations for new plant. If absolutely necessary we would need to understand why a derogation was necessary depending on the plant technology and topology.	Generally the national code should be adapted and updated to fit the needs of the society as well as the techincal development within the area while also taking into consideration the existing capabilities of the power system.
RFG NC	15.6.c.(iii)	at the request of the relevant system operator or the relevant TSO, the power-generating facility owner shall provide simulation models which properly reflect the behaviour of the power-generating module in both steady- state and dynamic simulations (50 Hz component) or in electromagnetic transient simulations.	Parts of the models provided by manufacturers are encrypted for confidentiality reasons, how do you assess the perform the model verification process of these encrypted parts?	It is not strictly necessary to be able to look into the models to perform model verification. The models need to agree on the network performance, not on internal signals.	to be studied on a european expert group on this topic (ENTSO-E).	We generally do not like encrypted models. That said we can have confidentiality agrrements put in place so we can share data and models.	currently we verify through simulations using the provided models. We also take an active part in the projects and review the studies and reports of the HVDC system and the models.

Table 7-2 : Part A - Questions and TSO answers (Part 2/2)

Question		Answers DK-Energinet	Answers DE-Tennet	Answer National Grid ESO
In several articles, reference to the "relevant TSO" is made. In your opinion, who will be the relevant TSO for the following components of a hybrid asset?	Onshore HVDC converter station	Onshore TSO	The TSO responsible for the control area at the onshore side	The relevant TSO (National Grid ESO) will operate the Onshore and Offshore assets (ie cables, HVDC Converter Stations,(onshore and offshore etc) but the assets are owned and maintained by a separate Offshore Transmission Licensee including the Onshore Converter Station. In this case the TSO is considered as the Transmission Operator (National Grid ESO) but the Transmission Owner of the Assets is a separate company appointed through a competitive tender process.
	Offshore HVDC converter station connected to a DC bus/hub	unbundled TSO's as it is an interconnection between two or more price zones, owner of the HVDC could be OWF owner or an OFTO	A TSO or consortium of TSOs who owns/operates the DC Hub	See above – The relevant TSO (National Grid ESO) will operate the Offshore HVDC Converter Station connected to the DC bus/hub but it will be owned and maintained by an appointed Offshore Transmission Licensee
	Offshore HVDC converter station connected to an AC hub	Unbundled TSO's as it is an interconnection between two or more price zones, offshore HVDC stations between price zones (interconnectors own by TSOs)	A TSO or consortium of TSOs who owns/operates the AC Hub	See above – The relevant TSO (National Grid ESO) will operate the Offshore HVDC Converter Station connected to the AC hub, but it will be owned and maintained by an appointed Offshore Transmission Licensee
	DC-PPM connected to a DC bus/hub (via an offshore HVDC converter station)	Unbundled onshore TSO as it is an interconnection between two or more price zones	The entity responsible for the operation of DC-PPM	The DC Connected Power Park Module will be owned and operated by a Generator. The ownership boundary (ie between the DC Connected Power Park Module and Transmission System) will define the responsibility between the owner of the DC Connected Power Park Module and Transmission System. For all Offshore Transmission Systems, National Grid ESO will operate the Offshore Transmission System and an appointed Transmission Licensees will own and maintain the Offshore Transmission System. Any Offshore System which operates at a nominal voltage of 132kV or above is treated as Transmission in GB. For AC connector networks between offshore wind farms and the remote end HVDC Converter or nearest 132 kV AC connection point, the ownership can vary but would be agreed on a site specific basis

	DC-PPM connected to an AC hub	Unbundled TSO's as AC hub is part of interconnection between two or more price zones, alternatively designated OFTO, but interconnection assets are owned by TSO(s). HVDC for DC-PPM owned by plant owner or OFTO	A TSO or consortium of TSOs who owns/operates the AC Hub	See response to item d above.
	AC hub	The unbundled TSO's as it is part of interconnection between two or more price zones	A TSO or consortium of TSOs who owns the AC Hub	Any Offshore System which operates at a nominal voltage of 132kV or above is treated as Transmission in GB – in which case the Offshore Transmission System is operated by National Grid ESO and owned and maintained by an appointed offshore transmission licnesee. For AC connector networks between an offshore wind farm and the nearest AC hub, then any item of plant operating at 132kV or above would be treated as Transmission and hence operated b National Grid ESO. For any item of offshore plant operating below 132kV it is dependent upon the developer but it is more likely to be treated as Transmission in the case of Shared sites (ie two or more wind farms connected to an AC hub and the two wind farms are owned by different parties).
Who would be the HVDC system owner following an extension to a hybrid connection?	-	onshore TSO	A TSO or consortium of TSOs who owns the DC Hub	The appointed Offshore Transmission Licensee. The wind farm would be owned and operated by the Generator but the HVDC System would be owned and maintained by the appointed Offshore Transmission Licensee.
Would you recommend a re-definition of the "HVDC system" as discussed in this document to take into account AC hubs?	-	No	No	In GB the definitions are well defined. Anything that operates at 132kV or above (which would include an HVDC System) would be covered under the GB Offshore Transmission Arrangements. Where it is unclear is if the AC collector network is below 132kV or HVDC System has a low voltage and the generation was undertaken at DC. Invariably, the ownership boundary between transmission and generation at nominal voltages of 132V and below will depend on the type of layout and topology of the design

Table 7-3 : Part A – TSO answers to high-level questions

7.3. Part B – Questions and TSO answers

The consolidated answers from ENTSO-e to the questions of Part B are shown in Table 7-4.

Topic	Question(s) to TSO	Draft Consolidated Answers from ENTSO-e representatives
General	Do you agree that voltage levels (e.g. 320kV, 525kV) have to be enforced in the regulation?	No opinion
	Do you agree that standardized platform designs (including DC-busbar arrangement) are needed	No opinion
	Do you agree that a grid code has to include requirements on extensibility (which will force to add spare space on offshore platforms for potential future connections and protections	No opinion
Active power control and frequency support	To ensure the frequency stability of synchronous areas, a maximum loss of active power must be defined. The most traditional approach is to define a single value (e.g. size of the FCR). Because a higher loss can be technically acceptable during a very short amount of time, an alternative approach could consist in defining a lost-power over time characteristic (i.e. temporary loss of power to AC grid). Would you consider such a lost-power over time characteristic instead of a strict maximum loss of power criterion?	No opinion
	Without additional reliability data on multi-terminal HVDC and DCCBs, would you consider the loss of the whole hybrid asset as a single contingency (even if DCCBs are installed to ensure full selectivity)?	No opinion
Fault ride-through capability	Do you agree that a technical requirement on AC voltage Over Voltage Ride-Through (OVRT) has to be defined	Agree
	Do you agree that a technical requirement on LVRT and OVRT envelopes on the DC-grid has to be defined?	Agree
Other control schemes related to AC grid	Control interactions might occur on the AC-side (notably due to the increased penetration of power-electronic components). However, this is not specific to hybrid assets. Do you agree that it is therefore not a blocking point for their development?	No opinion

Power system restoration	Do you agree that hybrid assets must have black-start capabilities?	No opinion
Protection devices and settings	CENELEC defines that protection is evaluated based on the following values: a. time between fault inception and separation b. time between fault separation and power flow recovery in the healthy part of the system Do you agree that common requirements are needed on this aspect, in order to encourage development of hybrid assets?	Disagree
	Do you believe that these values should be defined by TSOs?	Agree
Information exchange and coordination	Do you believe that proprietary control is a blocking point for the development of hybrid assets?	Disagree
	Do you believe that developing a standardized converter interface is an important step towards hybrid assets?	Agree
	Do you consider that imposing the compatibility of converter controls (higher controls) with open-source control loops is a promising option to solve this?	Disagree
HVDC control and stability	Do you agree that defining acceptable DC-voltage ranges is an important technical requirement?	Agree
	Do you agree that power quality for DC-grids is an important technical requirement (e.g. acceptable distortion level of DC-voltage)?	Agree
	Control interactions might occur on the DC-side (e.g. between DCCBs and converters). This means that coordination is required between DC-grid planning, converter design and control. Do you agree that the “relevant TSO” responsibility is to verify that the DC-design of the DC-grid expansion does not cause adverse interactions on existing assets?	Agree
	Do you agree with the need for having a requirement on an HVDC control hierarchy (e.g. internal converter control, local DC-node voltage control, secondary coordinated control)?	Agree
	If a well-defined HVDC control hierarchy is used, do you agree that TSOs should be able to adjust settings of the higher control levels while the internal converter controls are tuned by the manufacturers?	No opinion

Table 7-4 : Part B – Questions and consolidated answers

8. APPENDIX B - QUESTIONS AND COMMENTS RAISED DURING THE WORKSHOPS

8.1. Comments/Questions raised during Workshop 1

The following questions and comments were raised during the first workshop by the participants:

1. Will you also work on expanding the system operation guidelines (separate from grid codes) to include HVDC systems?

2. Is it not so that even to make a connection to a hub it will require additional space compared to a P2P?

3. I'm surprised that you believe the current version of the NC HVDC does not cover stage 1, 2, 3 (except load), 4. Requirements are defined for separately for each extremity of HVDC system, for the collection network as well as for the mainland AC grid. Personally, I believe what you describe (except load connected to ac collection network) is already covered by the NC HVDC. Could you explain why you believe this version of the code is not sufficiently covering the system needs?

4. Just a comment: I think we should be careful to conclude that the existing HVDC grid-codes are sufficient to ensure interoperability in the case of point-to-point interconnection in weak offshore AC hubs

5. slide 21 assumes that two IC (or Hybrid) projects will use the same voltage. Why would they do this as separate commercial entities? This would require anticipatory investment. This does not sound good for consumers.

6. Can you elaborate on technical feasibility point? What were/are the concerns on technical feasibility and how are they addressed?

7. As a commercial IC and Hybrid Developer my connection point is at the onshore AC system. Why would I be designing around future connections?

8. How are you going beyond work delivered by PROMOTioN WP11 - which has structured and identified gaps?

9. Regarding future expansion, what is the time frame you will be considering in the study?

10. Will this project recommend a timeline or appropriate sequence of pragmatic steps to slowly develop the framework, or will it propose all recommendations to be implemented at the same time? A sequence of steps may better facilitate buildout of initial pathfinding initiatives.

11. To what extent are DCCB included in your previous topologies? How do you consider the impact of disturbances on the offshore system as impacting both onshore TSO areas?

12. The technical specification CENELEC TS 50654 goes a long way in describing and listing the aspects that need to be specified, coordinated and/or standardized for HVDC system development, along with

guidelines for their quantification. How will you use this in the current study?

13. When defining your connection requirements, will you ensure that the way requirements are defined do not restrain manufacturer innovation and variety of approach as well as are defined in a sustainable way?

14. Are you able to specify "one size fits all" requirements across all TSOs to inform integrated solutions like this? For example different TSOs will have different priorities for reactive and active power support and restoration specific to their networks. When multiple ends of an offshore system land on a single onshore system e.g. 2 or more points in GB, or 2 or more connections to continental western Europe then for an onshore disturbance- different voltage depressions, different priorities? Flexibility is critical.

15. How would "maximum loss of power infeed" be defined for a DC grid connection to a synchronous area? Specifically when DC grid connects at more than one point to a sync. area? Is N-1 contingency will consider only one DC line or whole DC grid?

16. August is a very inconvenient period for collecting and providing feedback to this topic with so many aspects, would you consider expanding the feedback periods?

17. In your point of view, how and by whom would the "Companion Guide" be used when it's ready?

18. Would the connection to offshore hydrogen production units have an impact on the requirements? If so, will this be considered?

19. The point across both my question of DCCB and one-size fits all is that there is a hierarchy of control dependencies that influence design. Resilience to onshore disturbances must of course be provided to at least the minimum of TSO codes that are relevant, but may have different control priorities influence offshore resilience, however offshore disturbances in these designs impact both TSOs and drive not just within TSO actions but also consequential actions that must be considered. Any offshore windfarm collector configuration needs to be resilience and performing against these consequential requirements. its not straight forward at all.

20. The use of the word 'hybrid' in the presentation mostly relates to the combined purpose of interconnection and offshore wind export in one transmission system. This is largely a regulatory challenge, and has less relevance for technical requirements. I think it is thus better to use a different word to keep the focus on the technical aspects.

8.2. Comments/Questions raised during Workshop 2

The comments and questions raised by the participants during the second workshop are listed below:

1. Can you please share some more information about the other 2 studies contracted by the European commission on planning, financing and market regulation?

2. Will there be a pubic consultation period also for the first two studies?

3. From the presentations it seems that much focus is in protection. However, interoperability between converters is also related to control during normal or transient operation. In addition, CENELEC has aimed in a clear split between converter equipment and switchgear. Have you kept this split in your guideline?

4. Should RfG and other connection codes be extended for AC hubs, or must a new set of requirements be created? Is there a robust definition of an AC hub to choose what set of requirements to apply?

5. Thanks for the presentation. Did you consider IEC 61892 (offshore) as a potential standard? It has some description for f and V deviations from "normal".

6. An observation: We do need to be able to describe an inverter-based power generation system, just so we can specify equipment and its performance standards.

7. One of the issues is that all equipment supplied to EU codes will be based on normal grid codes.

8. In AC hubs, GFC (Grid Forming Control) could support the low system strength issues. What do you think on the application of GFC on onshore HVDC station connecting hubs?

9. Should the choice of fault clearing strategy be fixed from the onset? PROMOTioN work showed that different fault clearing strategies can in principle co-exist in different parts of one HVDC system. Perhaps the requirements for HVDC systems and equipment should be such that they would allow for selectivity to be increased/changed in future by e.g. adding DCCBs at existing nodes in order to cope with changes in the DC and connected AC grids.

10. General question : The work that is done is very interesting and I agree on the importance to provide guidelines to improve specification/requirements. However, such transients (for instance AC and DC faults) are non-linear and extremely fast, therefore, there will be always a “gap” between specification and how vendors clearly understood/interpreted the specification. Small miss-understanding (or small deviation) by manufacturers will lead to a trip of the general system.

    To avoid (or limit) such issues, based on RTE experience, mainly : BESTPATH project and the two HVDC offshore parallel connection in grid forming in Norway (Johan Sverdrup project), we recommend strongly that EMT offline and real-time simulation to be performed during specification stage as wall as at design stage (and also during operation for optimization).I hope that this guideline also provides a recommendation on the approach to be used during specification stage as wall as at design stage, to ensure that such connection is possible.

I believe, that without such recommendation (i.e. on EMT studies offline and real-time simulation), such offshore connection can be jeopardize.

11. Are process considerations for vendor interoperability (e.g. types of studies to be done, model exchange, etc.) for offshore AC hubs comparable to those for offshore DC grids?

12. Considering the TSO's inclination to provide a secure and reliable grind and the extend of research going on in the field, one might say that it's only natural that the TSO's experts would recommend to postpone each project as long as possible for the technology and protection strategies have not crystallized out sufficiently enough today.

13. Offline model is important but will not be sufficient. Because there will be several issues such as model validation. Does the recommendation, highlight the importance to have physical control replicas + real-time simulation during specification and design stage?

9. Appendix C – First round of stakeholder Consultation

In the context of this project, consultation of stakeholders has been considered very significant in order to come up with meaningful recommendations. To this purpose the following meetings were organized by Tractebel during the first round of the stakeholder consultation:

- 02/07/2020: Meeting with ENTSO-e and North Sea TSOs
- 14/07/2020: Meeting with WindEurope
- 16/07/2020: Meeting with T&D Europe

The comments and questions raised during these meetings are listed in the following sub-sections. At several places, the answers or observations of Tractebel are included in blue colour.

9.1. Meeting with ENTSO-e and North Sea TSOs on 02/07/2020

9.1.1. Purpose of meeting:

The representatives believe there should be some coordination between them in order to answer these questions. Also, not all of them are clear, so clarifications should be asked.

9.1.2. Questions and comments on scope of work

The following questions were raised during the discussion on the scope of our work and the questionnaire:

- What is the scope of the project? Connection code or planning/design code? It is not clear because some of the questions refer more to planning than connection.
- What is the aim? Review the current grid codes?
- What is meant by national variations? From the grid code or between countries?
- Is a planning code or a connection code proposed? Planning should not be in the scope of the project. In the planning case, Cost-Benefit Analysis would be more relevant and cover an even wider scope.
- They believe Tractebel has not understood correctly the HVDC network code. Recommendations should be based on a clear understanding of the existing code.
- There is a scope of application of the HVDC code. The HVDC network code does not apply to AC hubs currently. One could conclude that the HVDC network code is not applicable to such hubs. Some requirements that could apply on these are very vague. These requirements were by intention not exhaustive.
- The outcome of this study should not bypass the legal process. There is a strict process for network code amendment This remark outlines that we should not use requirements but clarify that we proposed guidelines.

Tractebel observations:

As expected, several TSOs appeared very defensive and it appeared that they would prefer to minimize any potential changes. However, one of the representatives clearly expressed that the HVDC NC does not apply to MTDC grids for which new requirements have to be defined.

There was a misunderstanding of some terms (e.g. DC hub) which was the reason behind the comment "that Tractebel has not understood well the HVDC grid code". This was resolved during the meeting, but clearly illustrated the need to clearly define each term.

The main message from TSOs is that system needs are the most important. The current grid codes work well now but in the future the systems will have already to face several challenges with renewables. They want to make sure that any type of offshore assets will not impose additional constraints/complexity on the onshore grid.

9.1.3. Discussion on part B of questionnaire:

The representatives clarified that they want to provide a consolidated response from all (or at least most of) the TSOs on the questions in part B.

- Q1: Do you agree that voltage levels (e.g. 320kV, 525kV) have to be enforced in the regulation?
  The representatives stated that the voltage levels should not be enforced in a regulation, but that they are decided through coordination.

- Q2: Do you agree that standardized platform designs (including DC-busbar arrangement) are needed?
  According to the representatives the platform design is a part of the grid development . The interface of the converter has to be standardized to the rest of the equipment and not the platform. Several TSOs expressed their opinion that grid code requirements do not care about standards. Instead, system needs are the driver for grid codes regardless of standards. According to them standards are the lowest level of agreement between manufacturers.

- Q3: Do you agree that a grid code has to include requirements on extensibility (which will force to add spare space on offshore platforms for potential future connections and protections)?
  The representatives do not consider this relevant for connection codes.

- Q4: To ensure the frequency stability of synchronous areas, a maximum loss of active power must be defined. The most traditional approach is to define a single value (e.g. size of the FCR). Because a higher loss can be technically acceptable during a very short amount of time, an alternative approach could consist in defining a lost-power over time characteristic (i.e. temporary loss of power to AC grid). Would you consider such a lost-power over time characteristic instead of a strict maximum loss of power criterion?
  According to the TSO representatives it is difficult to answer this question. After explanations that this may affect the MTDC grid protection design, the opinion was expressed that only full selectivity is accepted by their side as a protection strategy. The lost power over time characteristic seems like a new concept to the TSOs and they cannot recommend something like that since the impact to the system is not known.

- Q5: Without additional reliability data on multi-terminal HVDC and DCCBs, would you consider the loss of the whole hybrid asset as a single contingency (even if DCCBs are installed to ensure full selectivity)?
  The representatives agreed that this is more related to planning criteria and not connection codes.

- Q6: Do you agree that a technical requirement on AC voltage Over Voltage Ride-Through (OVRT) has to be defined?
  All representatives expressed their agreement.

- Q7: Do you agree that a technical requirement on LVRT and OVRT envelopes on the DC-grid has to be defined?
  All representatives expressed their agreement.

- Q8: Control interactions might occur on the AC-side (notably due to the increased penetration of power-electronic components). However, this is not specific to hybrid assets. Do you agree that it is therefore not a blocking point for their development?
  Encrypted models is not seen as a blocking point by the TSOs. Such problems can be solved with the right interfaces and control tuning. But the problem of interactions exists of course and it cannot be precluded it is not a blocking point.

- Q9: Do you agree that hybrid assets must have black-start capabilities?
  Black-start is coupled with restoration procedure and system needs. But it would be beneficial if they have the functionality.

- Q10: CENELEC defines that protection is evaluated based on the following values:
  - time between fault inception and separation
  - time between fault separation and power flow recovery in the healthy part of the system

  Do you agree that common requirements are needed on this aspect, in order to encourage development of hybrid assets?
  In their opinion, full selectivity should be ensured. Article 17 of the existing HVDC NC should be respected.

- Q11: Do you believe that these values should be defined by TSOs?
  The TSO representatives agree to this.

- Q12: Do you believe that proprietary control is a blocking point for the development of hybrid assets?
  The TSOs disagree. Encrypted models are not considered a blocking point

- Q13: Do you believe that developing a standardized converter interface is an important step towards hybrid assets?
  Work has been recently published by ENTSO-e proposing a standard interface.

- Q14: Do you consider that imposing the compatibility of converter controls (higher controls) with open-source control loops is a promising option to solve this?
  The TSOs believe it is nice to have compatibility, but the word "imposing" causes issues. They believe that open models are not obligatory and other ways to bypass this issue exist.

9.2. Meeting with WindEurope on 14/07/2020

The feedback provided by WindEurope during this meeting is provided below.

TECHNICAL REQUIREMENTS FOR CONNECTIONS TO OFFSHORE HVDC GRIDS IN THE NORTH SEA

WINDEUROPE FIRST ROUND FEEDBACK AND QUESTIONS

General feedback

- **Scope:** We believe the scope of the study is meaningful as there is indeed a need to investigate the different technical aspects and respective regulation gaps in view of a transition from point-to-point to multi-terminal offshore grid connections.
- **Investigation areas** need to be clearly defined and disassociated. See diagram at the end of the document
- **Milestones**: To provide a meaningful Companion Guide for NRAs and TSOs, we recommend postponing the feedback periods to September or October. Given the complexity of the topics, two weeks in August is certainly not a convenient period for collecting meaningful feedback.

Specific comments/questions

1. **From point-to-point to hybrid assets**

- **Will you define how "offshore hybrid assets" are considered in this study?** Which potential configurations will you consider (e.g. OWFs connected upstream/downstream to the interconnection point so subject to one national grid connection code, OWFs considered connected to both/all countries so subject to two or more grid connection codes? OWFs connected to country-neutral hubs?) The different configurations should be defined at first stage
- **When defining configurations, which is the considered time frame?** 10-15 years is possibly not long term enough to ensure extendibility
- Some more specific comments on the slides to be included in the document to share

2. **Voluntary set of technical rules (Companion Guide)**

- **Binding requirements**: It needs to be clear that binding requirements will only be stated in the Network Codes. Any additional recommendations that may be applied in the different countries should be put to public consultation either through the GC ESC (new Expert Group or Implementation Guidance Document to be publicly consulted) or through the national stakeholder committees.

3. **Technical challenges/Methodology**

- **As-Is situation:**

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- It is not correct to say that there's a trend towards 700MW 220kV AC-platforms. Fact of the matter is that TenneT in the Netherlands some years ago decided on this specific design for connecting a number (5) of offshore windfarm areas. This was decided at a point in time when 220kV and ~350MW were the highest submarine cable voltage and rating available. Since then higher voltages and higher ratings have become available in the supply market, and currently 220kV are used in projects in UK for connecting more than 400MW per submarine cable. **Hence the trend today actually is towards higher voltages and higher ratings than 220kV and 700MW**. Likewise, for HVDC 900MW at 320kV was a decision TenneT in Germany made for a series of HVDC offshore platforms, but the trend today is towards higher power rating enabled by increased current rating of power electronic modules and cables. **Hence both 220kV/700MW HVAC and 320kV/900MW are examples of specific choices made for the initial projects that have become constraints preventing the later projects from benefitting from developments in the supply market that has taken place after the decisions were made.**

- Innovative platform concepts are not only manufacturer dependent but also requirements dependent.

- **Extendibility:**
  - Great care should be taken not to impose restrictions on future development of HVDC solutions by standardizing HVDC designs too rigorously now when neither HVDC networks nor commercial HVDC breakers exist.
  - **Probably, "alignment across projects with similar timeline" is a better expression than "standardization" at this stage.**
  - Standardized platform designs should be limited to preparations for future expansions / future interconnections.
  - HVAC voltage levels 220-285kV, 300-330kV and 380-400kV are in common use by TSOs in Northern Europe. These voltage levels will also work fine for the HVAC parts of an offshore network. It's perfectly possible to use 220kV off the coast of the Netherlands and Denmark (and 150kV off the coast of Germany), and then use 275kV or even 400kV for other areas (e.g. further offshore) if that turns out to be more optimal once such other areas get developed.
  - Likewise, HVDC system are typically +/- 320kV or +/- 525kV today, but also intermediate voltage levels such as +/-400kV are sometimes used, and +/-600kV can be expected according to ENTSO-E
- **Protection/control:** Will you consider the potential resonance of your recommendations on national system operation network code – and not only grid connection code - requirements

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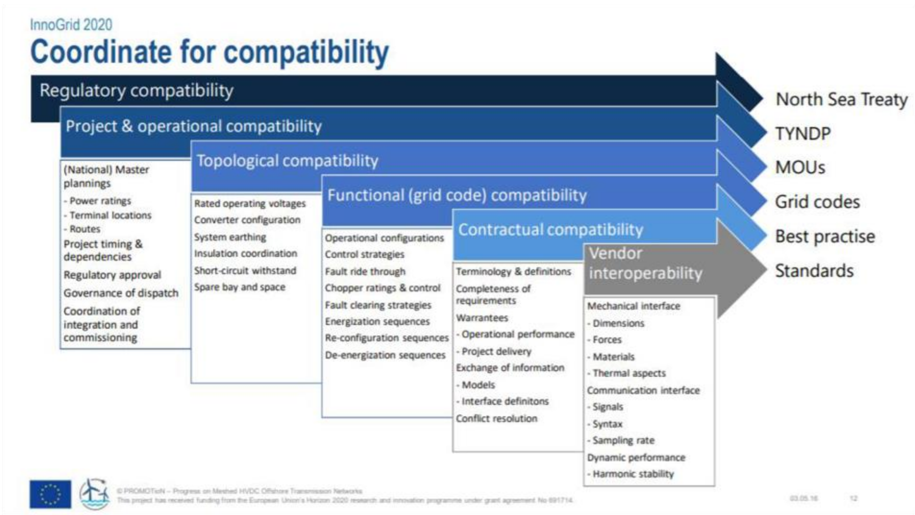
that might affect both offshore and onshore grid operation in each country (e.g. operational security requirements, voltage control, reactive power control, frequency parameters and many other)? Could this lead to recommendations for harmonising also some system operation requirements (current SO GL only deals with AC side), or system balancing? **Overall, which national Network Codes will you consider in your analysis?** Will you make recommendations for further analysis/next steps to be taken in addressing regulation gaps in the entire set of relevant network codes?

- **Existing technical committees and standards:** Which ones will you consider as references?
    - The technical specification CENELEC TS 50654 lists the aspects that need to be specified and/or standardized for HVDC system development and gives guidelines on how to define the functionalities. Will this be considered?
    - **Interoperability**: The presentation barely mentions the fundamental challenge of securing inter-operability of HVDC converter controls and protection in a multi-vendor HVDC network. The work should really make clear recommendations to the EU Commission / Regulators on how to secure that different vendors solutions will work together. Will you consider the ongoing work at CIGRE (WG 1 No B4.85)?
    - ENTSO-E just formed an Expert Group on Interaction Studies and Simulation Models (for generation units, HVDC and demand units) as part of the European Stakeholder Committee on Grid Connection Codes. The aim is to find a consensus and to harmonise the requirements across countries on this issue. The outcome of this work should play a significant role and should certainly be considered in your study. However, this outcome will not be published before the end of 2020. Are you planning to engage in these EG discussions and follow the development of the recommendations in parallel?



9.3. Meeting with T&D Europe on 16/07/2020

9.3.1. Questions of T&D raised during the meeting or shared by email

After a roundtable presentation of the participants and a brief summary of the first workshop by Tractebel, T&D raised the following questions:

With respect to the questions that were raised on the project "Technical requirements for connections to offshore HVDC grids in the North Sea":

- Is a real possible project being addressed or is the focus on theoretical scenarios?
- Is the focus on "commenting" and elaborating on existing grid codes? Or also the proposal of new requirements?
- Is there also a focus on DC-side grid code? (e.g. based on CENELEC guidelines)
- How will black start with Offshore wind be addressed, as this requires a new concept of operation compared to now
- Who takes responsibility for HVDC grid control? Responsibilities (DC TSO?) and technical requirements for the DC side?
- Why is 220 kVac considered as the collector voltage rather than, say, 66 kVac?
- On slide 14, please clarify what is the co-ordination between bipole and monopole
- On slide 16, please explain the use of "switching stations" in some examples
- What will be the assumed control strategy for the multi-terminal operation?
- How will the economic impact of protection strategies be reflected in the resulting recommendations?
- On Slide "On which components will requirements apply?" Why are offshore and onshore stations differentiated? What is the reasoning behind it?

General questions:

- Will Hardware in the Loop be used also?
- How does an extension of the DC grid modify the functional requirements

Not asked but of interest:

- Where is the currently used converter and higher level control taken from? (i.e. papers? Newly developed?)

9.3.2. Presentation of Project X

The last part of the meeting was a presentation by T&D Europe of Project X – Multi-vendor MTDC.

This is a project proposal on a joint, multi-vendor HVDC grid that T&D Europe is preparing to implement in the North Sea. Such projects could help in gaining more practical experience and knowledge.

9.3.3. General comments on DC grid code

The following comments were noted by Tractebel during the discussion on the relevant of DC grid codes:

- Codes are not desirable before acquiring some knowledge and practical experience on HVDC grids and the technology further matures

- According to T&D, the DC requirements (i.e. DC-side information exchange, control, protection functions, etc.) have to be specified by the TSOs.

10. Appendix D – Second round of stakeholder Consultation

The following meetings were organized by Tractebel during the second round of stakeholder consultation after the second workshop on 31/08/2020 and 02/09/2020:

- 10/09/2020: Meeting with TSO expert A
- 11/09/2020: Meeting with TSO expert B
- 15/09/2020: Meeting with T&D Europe

Additional feedback on the draft version of the Companion Guide was requested and received by email from representatives from ENTSO-E and WindEurope. These are also provided in the next sections.

In general, the stakeholders expressed their positive feedback on the overall content and the recommendations in the Companion Guide. The main remarks were on:

- the importance of accurate simulation models in order to enable meaningful studies;
- the need for real-time replicas to decrease the risk of HVDC projects;
- the willingness to move towards a network code for DC grids (either as a new document or by amendment of the existing network codes), but only after more experience has been gained, and preferably via a collaborative approach.

10.1. Meeting with TSO expert A on 10/09/2020

The following comments on specific sections of the Companion Guide were shared by the TSO expert.

10.1.1. Section 6.1.1.

The part in yellow below (see Figure 10-1) is true but has a very huge impact on the current way to foresee the design of assets. Currently TSOs try to perform a "fit and forget" approach, meaning that the design should be normally valid for the whole lifetime of an asset/client based on clearly defined requirements. The expert thinks that somewhere in the report this major change in the approach should be underlined.

Projects as BestPaths, as well as industrial projects, have shown that at the level of requirements, not everything can be covered and that when they have to do with complex controlled devices as PEID, they should expect rather a continuous process to avoid issues (mostly related to control interaction and multivendor issues) than a set of fixed requirements.

The expert sees this as a set of assessments, based on models/replicas/tests from requirements to detailed design to operation to be sure that everything runs as smooth as foreseen (no interaction and respect of the requirements).

They are missing today even a "standard" approach /guidelines to perform such kind of interaction studies.

This is true for current assets but it will be even truer for the new topologies analysed by Tractebel. Could Tractebel think that some of this considerations above can be inserted more explicitly in the report?

6.1.1. Alignment of designs for topological compatibility

The "Topological compatibility", as presented in [10], makes reference to the common design choices of separate HVDC projects that would facilitate their potential interconnection. This includes the aspects described in the following sections and emphasizes that coordinated planning is of key importance in the development of hybrid projects.

Due to the specificities and maturity of HVDC grids, it is recommended to have a strong coordination between system planning, grid connection and system operation. For example, any topological changes (not planned in the initial design) might need additional studies and adaptation. Therefore, a strong coordination between the relevant TSOs and ENTSO-E in the grid expansion plans is highly recommended. It is however believed that there is already a strong level of coordination between these entities.

Figure 10-1: Extract from draft version of Companion Guide

10.1.2. Section 6.2.3.4

Does Tractebel suggest to have different sets of parameters pre-defined to be changed in real-time or during commissioning?

How would the responsibility with the manufacturer be handled in this case where the TSO would probably not want to be liable for consequences of modification of parameters?

10.1.3. Section 6.2.6.2

See comment on 6.1.1.

10.1.4. Section 7.3.2.2 & 7.3.2.4

For injectors there is a risk of losing the whole injector with very fast responses. For example, the Machine Side Converter in a full converter wind turbine may lose synchronism in case of too fast injection variation. This may have an impact on the sizing of the DC energy dissipation.

In addition, with an HVDC link, they should take into account that the cessation/adaptation of active power injection impacts directly the onshore side of the installation and that this has to be coordinated with the rest of the synchronous area.

The proposal is to specify in the guidelines the dependence on the technology and other constraints (i.e. onshore network)?

10.1.5. Section 7.4.1.2 & 7.4.1.4

While it is clear that frequency can be quite fluctuating in an AC HUB and that PEID have fewer limitations than synchronous generators, this may not be the same for voltage.

Also, auxiliary loads and in general loads in the AC-hub can be really much cost-impacted on the voltage limits widening (e.g. there is an impact on V/f constraints for fluxes of transformers).

Has Tractebel looked at the impact of a broader voltage above +/-10% range on the asset cost in its assessment?

10.1.6. Section 7.5.4

The expert sees here a very high gap currently not only on simulation model exchanges but mostly on quality of simulation models.

As most of the manufacturer EMT models are blackbox, i.e. encrypted, it is very difficult to assess their compatibility with the type of study to be performed (i.e. what is inside the model), to extract responses to be used in system assessment and to be sure that the parameters in the model are actually up-to-date.

Indeed replicas may solve part of the problem (at least for part of the control system). However they should strive for better models and more transparency on the model limitations when it comes to complex designs as the ones foreseen in the AC Hubs.

This is in one of the most critical and difficult to solve points as it does not involve only technical challenges but also IP issues. Maybe it is useful to underline this in the Companion Guide.

10.2. Meeting with TSO expert B on 11/09/2020

The main comment of the second expert (from a different TSO) concerned the necessity to use replicas. The following comments were raised:

- Replicas should be used already from the early stages of the project and not only after commissioning.
- Use of replicas at early stages can greatly decrease the risk of a project by revealing any interoperability issues before the commissioning of the equipment.
- The current level of simulation models probably covers around 80-90% of cases. There is still a 10% risk though that the system might not be able to work due to interoperability issues, not detected by simulations.
- Point-to-point connections were usually manufactured by a single vendor who built and used the replica.
- In multi-vendor MTDC grids the intellectual property of the vendors should be protected. Specific procedures have to be set up to ensure this. One option is to have an independent actor collecting and using the replicas.
- Examples of projects where replicas had to be eventually used to solve issues, either due to interoperability problems or due to the lack of offline models.
- There is a tendency to use replicas with more and more TSOs choosing to buy them. This should be mentioned in the guidelines, but it is perhaps too early to impose it in a network code

10.3. Feedback from ENTSO-E on Companion Guide

The representative from ENTSO-E expressed their appreciation for being kept in the loop of the development of the projects. They expressed that the efforts of Tractebel to collect wide feedback from all relevant TSOs are appreciated.

The following remarks are **not a consolidated opinion of ENTSO-E**. They should be read as a **non-exhaustive** and **high-level summary** that represents **the view of several TSO experts** that are mainly involved in Connection Network Code activities at ENTSO-E:

- They observed that a great number of the points that were discussed in the previous dedicated call on 02/07/2020 have been incorporated in the current draft.

- The report overall drives the development of DC requirements which is out of the scope of the current CNCs. No doubt that experience and dedicated system studies are still needed to proceed to that direction, it is difficult to judge at this point in time whether the scope of the current HVDC code should be extended or a separate Regulation should be launched. They consider further deliberations necessary about the way forward and its timing.
- ENTSO-E has recently published its first views on a number of aspects of Offshore Development and further position papers are to come.

10.4. Meeting with T&D Europe on 15/09/2020

10.4.1. Overall feedback T&D Europe

T&D Europe have expressed their full support on Tractebel's approach to develop technical guidelines at the PoC of an installation, e.g. of an AC/DC converter station, to assure interoperability of the technical solutions provided by different vendors. They understand that the information needed to define such guidelines will be based on literature review including existing network codes, CENELEC standards, CIGRE TBs and publications of European Projects and ENTSO-E.

However, while the presentation by Tractebel and SuperGrid Institute mentions CENELEC several times in the context of guidelines, they are missing specific details pointing to such guidelines, which are already standardized and published. Especially CLC/TS 50654-1 and -2 "HVDC Grid Systems and connected Converter Stations - Guideline and Parameter Lists for Functional Specifications" appears to be most relevant since it addresses all technical HVDC topics that are specific for HVDC Grids. This includes guidelines to the specification of global functions in the DC grid, such as DC circuit topology, DC voltage, or Control and Protection as well as guidelines to the specification of individual installations, like AC/DC converters or DC switching stations. Besides that, related guidelines for modelling and testing are included. The CENELEC documents are the result of a collaborative effort by the industry, TSOs, Academia and other interested parties. It is currently continued on IEC level by IEC/TC 115/WG 15.

10.4.2. Remarks raised during the meeting

The meeting on 15/09/2020 had two main objectives:

- Presentation of the latest version of the CENELEC guidelines by T&D Europe
- Open discussion on the Companion Guide

The following points were discussed:

- Latest release of HVDC guidelines was on June 2020. The work is continued by an IEC working group. The basis is the same set of documents. Since some aspects are not elaborated in the CENELEC document (DC-DC converters and DC transmission lines) IEC will complete them as appropriate and review the whole document.
- The CENELEC guidelines are a very broad document that intents to cover all functional requirements that are HVDC-grid specifics, not just connection.
- Grid forming is not explicitly considered in the CENELEC guidelines. T&D Europe considers grid forming functionality essential for future power systems, where state-of-the-art VSCs will replace more and more conventional rotating machines. However, the functional requirements of grid forming are currently elaborated by other organisations like CIGRE. The HVDC Grid specific aspects of this function can than be included into the TS 50654 once available.
- The case of AC hubs and "interlinked HVDC systems" was discussed. T&D Europe agrees with the "interlinked HVDC systems" concept. They consider it as a very

interesting point, that could be a key building block for future integrated offshore grids. Up to now the CENELEC document had focused on the DC side of HVDC grids.
- A DC switching station could be used to configure the various connections in HVDC grids for the connections would not depend on one converter station alone but rather on the overall HVDC grid operation. In addition, it could clearly separate the responsibilities of the vendor and of the HVDC system integrator (or relevant TSO) in HVDC grids.
- At the current maturity level, T&D Europe believes that real-time replicas are really important. This opinion will be re-evaluated as soon as more experience is gained. Replicas are important to decrease the risk of the projects. The quality of the offline models is still in a process of improvement.
- The protection zone matrix is a useful guideline to design the protection of an HVDC system and should be included in the Companion Guide.

10.5. Feedback from WindEurope on Companion Guide

The feedback provided by WindEurope on the draft version of the Companion Guide is provided below.

TECHNICAL REQUIREMENTS FOR CONNECTIONS TO OFFSHORE HVDC GRIDS IN THE NORTH SEA

WINDEUROPE FEEDBACK ON THE COMPANION GUIDE

WindEurope welcomes Tractebel open format consultation on the Companion Guide developed under the framework of the ongoing EC study on "Technical requirements for connections to offshore HVDC grids in the North Sea".

General feedback

1. **Purpose of the study:** The document clarifies that this is a Companion Guide and not a binding document**. However, if the long term purpose of this work is to establish a basis for a complete review of the HVDC Network Code, this should be stated much more clearly, its development work should have been done based on a much more collaborative approach between TSOs, offshore generation stakeholders, non-TSO HVDC system developers, owners and operators, HVDC suppliers, and all other relevant stakeholders. Also, the dedicated consultation periods should have been much longer and corresponding to the analysis needs of such complex issues.**

2. **Interlinked HVDC systems:** The document should justify clearly the need for more harmonisation in case of **interlinked HVDC systems** as compared to what is commonly called today a "Hybrid Project" that is a single interconnector (between two countries) with offshore wind farms connected to it. The current HVDC Network Codes already address single interconnectors. The need for more harmonisation has not been clearly explained in the current document.

3. **HVDC system ownership and development: The document should reflect the fact that HVDC systems in Europe are today build, owned and operated also by non-TSO companies**. For example, as enabled by the UK Energy Act, the upcoming offshore transmission system will be developed by non-TSO companies such as Equinor, Vattenfall, Ørsted and others, and ultimately owned and operated by Offshore Transmission Owner (OFTO) regimes typically owned by financial (non-TSO) investors. The document should address this fact in each part it discusses about requirement formulation, coordination and exchange of information (for example, not only between TSOs and HVDC OEMs but also with other non-TSO HVDC system owners and operators).

4. **Compliance at AC/DC onshore/offshore interfaces**: The contractual Point of Coupling (PoC) may differ from country to country. In some countries HVDC systems may be required to fulfil requirements at all interfaces (onshore AC side, DC side, and offshore AC-side) whereas in other countries either offshore or onshore. This fact should be considered and noted in the document.

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5. **Requirements on operating voltage ranges**: Chapter 7 presents a gap analysis of technical requirements for offshore "AC hubs" and how the current Network Codes should be complemented. This is a good high-level analysis, but some issues are not addressed:

   a. The document argues that the voltage range of operation of the offshore AC grid shall be bigger than ±5%, - up to ±10% or ±15%. To our understanding this would require overrated components as the power electronics components are designed for the highest voltage and the highest current (at low voltage) they need to comply with. Increasing the required operating voltage range would result in converters operating at high voltage (+10%) and low current (80% of the nominal), or at low voltage (-10%) and high current (100%), to have constant power output. **To justify such requirements, this document should include or recommend cost-benefit analysis to measure the impact of applying such operating ranges.**

   b. The same applies for frequency ranges. Furthermore, the consideration of "non-standard" frequency ranges is expected to be a costly choice, given that all components' testing will need to be repeated.

   c. There is no reflection on testing and coordination aspects between different projects at different life stages, e.g. if 56Hz are considered for a project today, what will be the cost implications for a new project to be connected in some years from now, having also to apply a 56Hz frequency.

6. **Consideration of AC and DC cables**: The technical requirements and parameters resulting from the necessary use of cables is not reflected at all in the document. Cables being the technology enabling the offshore grids, we would suggest considering the addition of some content in this matter. For example, Chapter 6 focuses on control and protection within the HVDC converters where the DC cable systems assumed to be utilized can be regarded as (almost, at least) a static component. Chapter 7 addresses the potential creation of "large offshore AC hubs" to connect both generation, loads, and HVDC VSC links, all connected via an AC system (i.e. AC cables) - but without addressing the potential impact the AC cables will have on the whole system pending on power rating, voltage levels and distances. There seems to be no consideration of the typical phenomena a large/long AC cable system, especially in combination with a weak AC system, may cause. For example, please see the figure below that includes "AC tie-line (long)".

   We would like to suggest the following comment in this vein: "*For a potential offshore isolated AC Hub, as described in Chapter 7, it is necessary to address the interaction between the involved AC cable systems and the rest of the AC Hub system, to correctly understand the expected technical challenges*"

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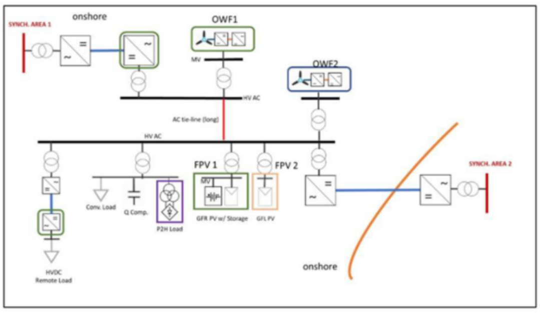


Figure 7-1: Generic Structure of an AC hub based Hybrid project: Wind, PV and Storage as well as conventional and P2X loads are included.

7. **Simulation Models**: For such big projects, in addition to RMS and EMT offline, real time simulations including replicas could be also recommended to de-risk the system. Real-time simulation with replicas is increasing in popularity in Europe; Today, RTE and RTEi have such a platform since 2011, recently the National HVDC centre (SSE) and REE have developed such real-time platforms while other TSOs are foreseen to develop similar labs.

11. APPENDIX E – HVDC PROTECTION CASE STUDY

This appendix is a support document for the "Companion Guide", which proposes recommendations for the extension of the Network Code requirements for future hybrid projects. The methodology for the identifications of those requirements lays on literature review and expert knowledge and is supported by EMT power system simulations. This report presents advices for protection strategies when considering future extensions of a DC grid. EMT simulations have been carried out focusing on two types of protection strategies:

- A protection strategy based on full-selective fault clearing philosophy employing hybrid circuit breakers in series with DC limiting reactors.
- A protection strategy based on a non-selective fault clearing philosophy employing mechanical circuit breakers.

Two grid configurations have been studied, namely the bipolar and the symmetric monopolar configuration. A complete and extensive analysis considering all type of fault cases, grid topologies and protection strategies is out of scope of this report. By contrast, the chosen approach is an expert selection of the simulation cases considering the specificities of the selected protection strategies and grid configurations.

The report is structured as follows: Chapter 11.1 introduces the concepts of a protection strategy and fault clearing philosophies. Chapter 11.2 presents the benchmark DC grid considering possible future hybrid projects in the north Europe as well as their possible extensions. Chapter 11.3 describes the models that have been used within the EMTP-RV simulations. Chapter 11.4 introduces the protection strategies considering primary sequences for line fault and busbar fault as well as one backup in case of line fault and a breaker failure. Voltage rebalancing sequences are also presented for the pole to ground fault in a symmetric monopolar configuration. Chapter 11.5 investigates different fault scenarios showing the significant voltage and current signals as well as energy absorption of the protection components. From the analysis of the simulation results, general findings are presented for each fault scenario. As a conclusion, Chapter 11.6 brings a summary of the main results and technical challenges that have been highlighted during this study. Some of the takeaways are resumed hereunder.

Extension of an HVDC grid should take into account several technical constraints such as:

- DC voltage level
- grid topology (bipole or symmetric monopole)
- type of grounding
- maximum loss of infeed and AC system stability constraints
- DC insulation coordination (voltage level of SA)
- acceptable risk in case of fault and component failure (e.g. need for single or double busbar)
- employed protection strategy
- design of the existing protection component

For the strategy based on full selective fault clearing philosophy using hybrid breakers:

- The grid extension could have impact on the design of the existing breakers if the extended grid is realized through short cables or if there are high number of new converters close to the existing breaker or if the backup sequence (e.g. during breaker failure) entails long fault clearing time (e.g. in the order of 10 ms).

- Voltage rebalancing during pole to ground fault in case of symmetric monopole can be realised employing a DBS (Dynamic Breaking System) which is able to rebalance the voltage within around 10 ms. The energy absorbed by the DBS can vary with the length of lines to be charged; therefore during the design process the energy capability of DBS needs to take into account different grid configurations or extensions.
- For the calculation of DC fault currents the modelling of the AC wind farm could be realised using ideal AC voltage source in series with a short circuit impedance. This assumption can be no more effective if the fault clearing time is longer than few ms (e.g. during a backup sequence).

For the strategy based on non-selective fault clearing philosophy using mechanical breakers the main findings are:

- Grid extension has few impact on the converter breakers design but major effect on the line breakers for what concern the short time current and the fault clearing time. If the short time current becomes too high (e.g. higher than constraints imposed by electric components), a limiting inductor could be necessary in order to reduce this value.
- For the calculation of DC fault currents the modelling of the AC wind farm should be realised using aggregated VSC converters (e.g. in case of fully fed WT generators). Indeed, due to the long fault clearing time (10-15 ms), the current limiting mode of the WF converter could have a major impact on the DC fault current behaviour.
- Voltage rebalancing during pole to ground fault in case of symmetric monopole can be realised employing Pole Rebalancing Reactors (PRR) and takes around 100 ms. The design of the PRR (inductance and star point resistance) is strongly related to the stray capacitance and inductance of the DC system and thus the length of the cables. A suitable design of the PRR need to take into account different grid configurations or extensions.

11.1. Introduction

11.1.1. DC grid

All existing HVDC connections in the North Sea are point to point links between two countries or areas (interconnectors) or between off-shore wind farm (OWF) and the land. In the future such HVDC point to point links could be connected together to form hybrid assets. A first option can be a connection of two point to point links through AC side (A, Figure 11-1). A second option (B, Figure 11-1) is to use a DC/DC converter for the connection. A DC/DC converter (for example a back to back connection), can be used to adapt different DC voltages or different DC configurations. If some conditions are fulfilled the link can be realized with a direct connection on the DC side (C, Figure 11-1). This report focuses on guidelines of DC grid extension through direct DC connection for what concerns the DC protection strategies.

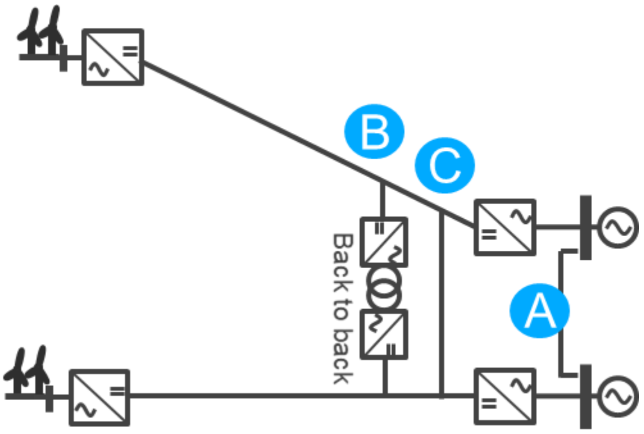


Figure 11-1: Different ways to connect two HVDC point to point connections together.

11.1.2. Protection strategies

A protection strategy can be divided in two main steps, see Figure 11-2, the fault clearing and the fault recovery. The first step, the fault clearing, begins after the fault occurrence and has the aim to eliminate the fault current. During this stage, the actions are carried out mainly by protection components like DC circuit breakers (DCCB) or converters with fault current blocking capability like full bridge converters. Three fault clearing philosophies have been proposed in (WG06, CENELEC/TC 8X, 2018) and (PROMOTioN Workpackage 4, 2017): the Fully-Selective (FS), the Non-Selective (NS) and the Partially Selective (PS) fault clearing strategies.

The fault recovery begins when the fault is isolated and has the aim to restore the voltage and the power. During this step the main actions are carried out by the converter controls and other protection equipment such as voltage rebalancing devices for the symmetrical monopolar configuration.

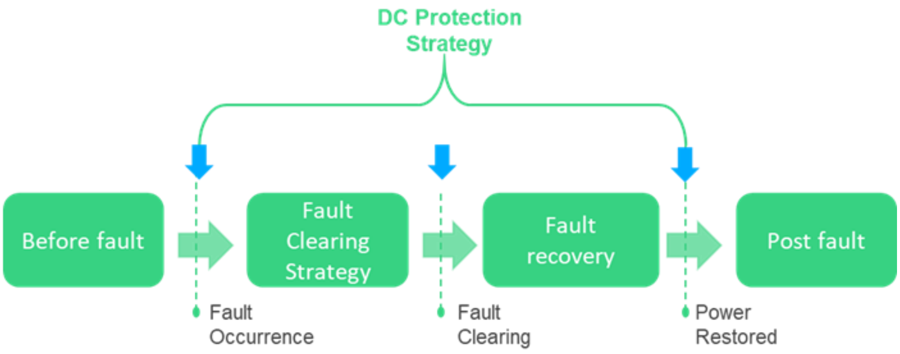


Figure 11-2: Protection strategy

In a fully selective strategy each line is considered as a protection zone; in case of a line fault only the breakers of the faulted line open selectively to eliminate the fault, Figure 11-3 (a). This kind of strategy employs high speed circuit breakers (e.g. hybrid DCCB) and requires DC reactors (DCR) to limit the DC fault current rise. This strategy is expected to have limited impact on AC network stability.

In a non-selective strategy the entire grid is considered as a protection zone, Figure 11-3 (b); in case of a line fault all the gird is de-energized by a non-selective action such as the opening of each DCCB at the DC side of the converters or by controlling the fault current to zero if the converters have fault current blocking capabilities (e.g. MMC Full-Bridge). During the fault clearing the faulty line can be identified and, once the fault is eliminated, the faulty line can be isolated by opening the line DCCB. After faulty line isolation the grid is reenergized and the power is restored. This kind of strategy employs low speed circuit breakers (e.g. mechanical DCCB) and requires no DCR or DCR with lower value of inductance compared to a full-selective strategy. This strategy is expected to have higher impact on AC network stability.

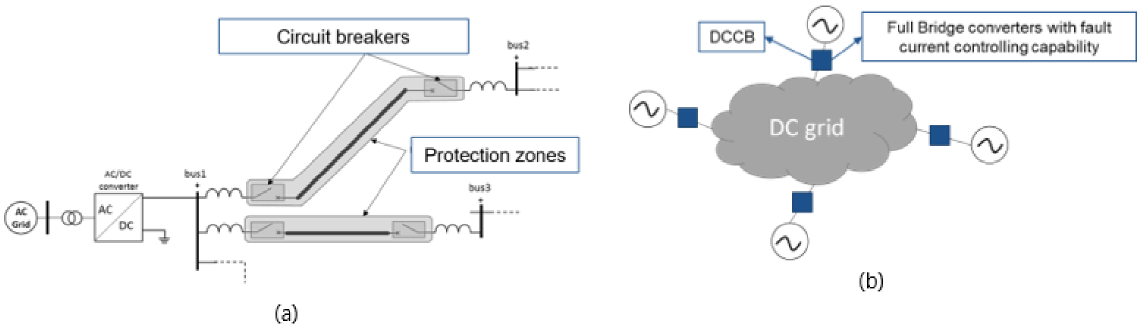


Figure 11-3: Protection zones in FS and NS fault clearing strategy

As already mentioned, within this report two protection strategies are studied:

- One full-selective fault clearing strategies employing hybrid DC breakers in series with DCR.
- One non-selective fault clearing strategies employing mechanical breaker at the converter side to eliminate the fault.

In this way two different extreme cases of protection strategies for future hybrid project are covered.

11.2. Benchmark DC grid

11.2.1. Benchmark grid

It is expected that the first multi terminal DC (MTDC) network will not be built as a greenfield project, but rather from the connection of pre-existing point to point links. The benchmark network studied is constituted of three pre-existing point to point links, see Figure 11-4:

- "GB": Converter Station 1 (CS) rated 1.8 GW; ±525kV, 100 km undersea cable from Offshore windfarm 1 (OWF1) to GB shore.
- "NL": CS2 rated 2 GW; ±525kV, 150 km undersea cable from Offshore windfarm 2 (OWF2) to NL shore.
- "DK1": CS5 rated 1.4 GW; ±525kV, 300 km undersea cable from Offshore windfarm 3 (OWF3) to DK1 shore.

The MTDC network is supposed to be built considering two extensions:

- Extension 1: in a first step the point to point links "GB" and "NL" are connected through a new undersea cable L23 of 50 km length. The MTDC formed is called "GB + NL".
- Extension 2: in a second step the MTDC "GB + NL" is connected to the point to point link "DK1" with a 300 km undersea cable L45. The MTDC formed is called "GB + NL + DK1".

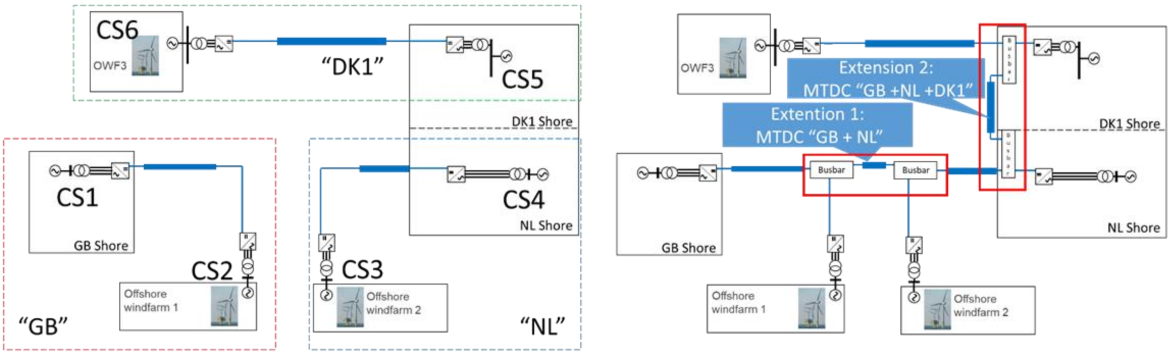


Figure 11-4 : Building of the MTDC benchmark network from several point to point links

The maximum allowed loss of infeed of the three AC zones ("NL", "DK1" and "GB"), see in Table 11-1, need to be considered during the planning and operation of the network. The condition is that, at any given moment, a fault on one transmission line should not cause a permanent loss of infeed higher than the maximum allowed Loss of Infeed (LoI).

Zone	Maximum allowed loss of infeed
GB	1.8 GW
NL	3 GW

DK1	700 MW

Table 11-1: Maximum allowed loss of infeed considered for the three AC zones.

Two versions of the benchmark network have been built: one for the bipolar configuration, see Figure 11-5, and one for the symmetric monopolar configuration, see Figure 11-6. The benchmark network for the monopolar configuration features two 700 MW pair of cables between converter station 5 and converter station 6 instead of one 1400 MW pair of cables in order to respect the maximum allowed LoI condition for DK1.

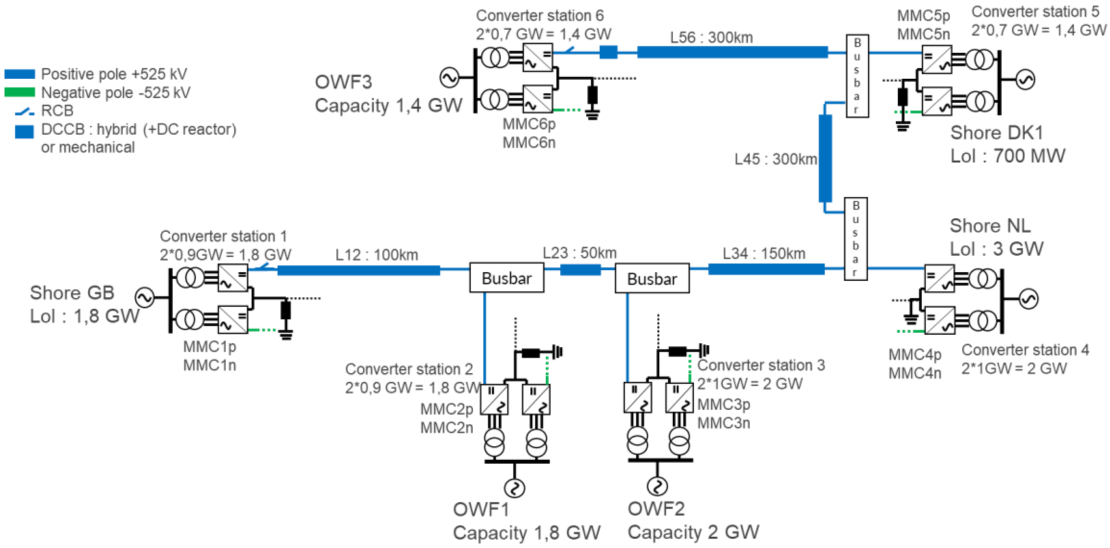


Figure 11-5: Bipolar benchmark networks

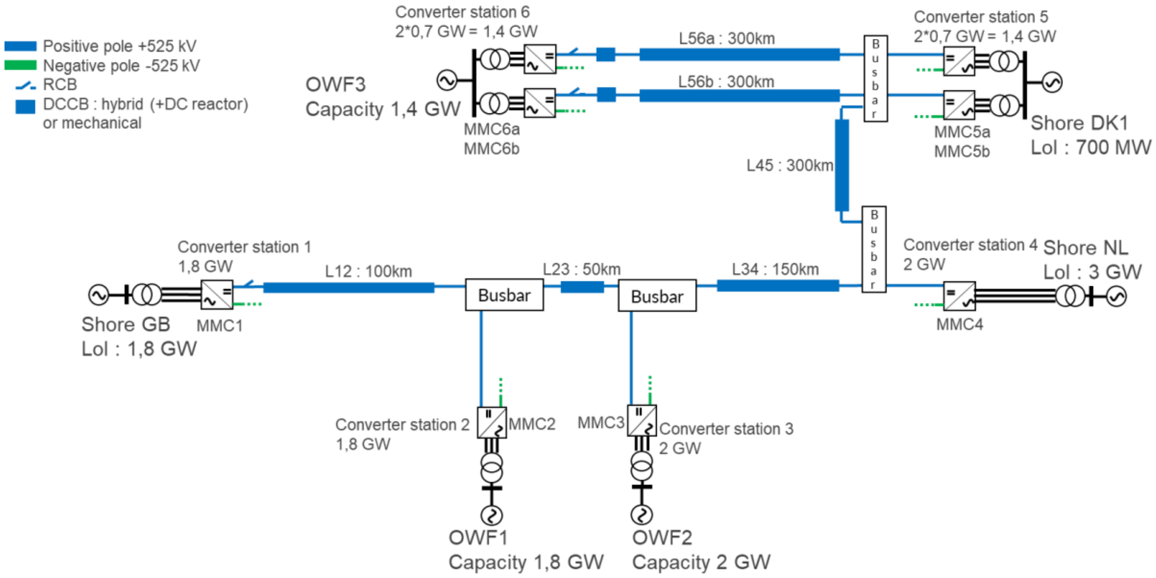


Figure 11-6: Symmetric Monopolar benchmark network

11.2.2. Main Assumptions

11.2.2.1. Voltage level

In order to ensure a direct DC connection between two existing HVDC links, see option C of Figure 11-1, both HVDC systems must operate at the same DC voltage. For this study, the chosen voltage is ±525 kV. This value is considered as the state of the art for the rating of HVDC cable and converters. Because the current in an undersea cable cannot exceed 2 kA, with a voltage determined to be 525 kV, the maximum power flowing through a pair of cables is 2.1 GW for a symmetrical monopolar.

It is worth to mention the choice of voltage should come from a techno economic analyse which is out of scope of this study. Same remark can be done for the choice of network topology and protection strategy.

11.2.2.2. Topology

In this study, two HVDC configurations are studied, see Figure 11-7, the symmetrical monopole and the bipole with Metallic Return (MR). Extension of the architecture is considered only between HVDC systems with the same topology.

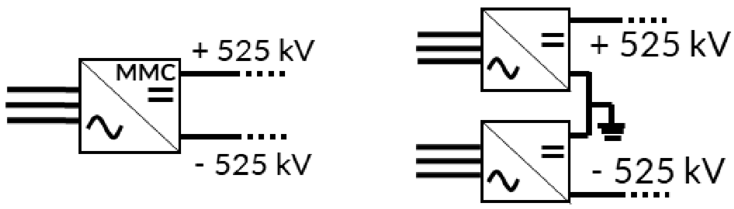


Figure 11-7: Symmetrical monopolar (left) and Bipolar (right) configurations

11.2.2.3. Type of faults

This report focuses on DC side faults. Because all lines are cables, every fault studied is considered to be permanent.

For the bipolar configuration, only line to ground faults are taken into account. A pole to pole fault is not considered in the scope of this study as it is deemed to be too unlikely if pole segregation is possible. For symmetric monopolar configuration, two types of short-circuit faults must be considered: pole to pole fault and pole to ground fault. The former type, similarly to the pole to ground fault on a bipolar configuration, gives rise to high steady state fault overcurrent while the latter, the pole to ground fault, will not lead to high steady state fault overcurrent but to large and sustained overvoltage on the healthy pole. For this reason, a voltage rebalancing sequence need also to be carried out after fault clearing for a symmetric monopole under pole to ground fault condition. The fault types and their main characteristics depending on system architecture are shown in Figure 11-8.

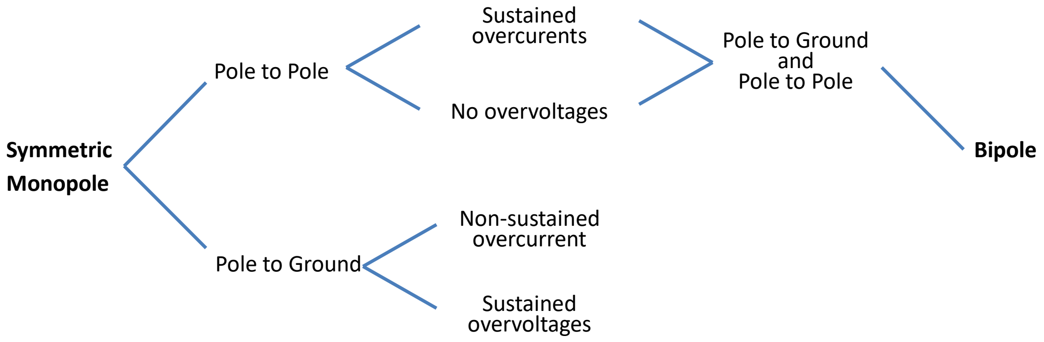


Figure 11-8. Fault types and main characteristics depending on system architecture (cable line)

11.2.2.4. Grounding

Symmetric monopole earthing can be realized in several manner at DC side or AC side. In this report it is assumed that the grounding is realized at the AC side at the secondary side of the transformer by means of a star point reactor, see Figure 11-9. The transformer is supposed to have Y/Δ winding connection in order to eliminate the third harmonic at the primary side of the transformer. Star point reactor has been used in project such as France-Spain (INELFE) link and South West Link and it can be considered as the state of the art grounding method for the symmetric monopole. The star point of the reactors is connected to ground via a resistance or a surge arrester. In a point to point link as well as in a MTDC grid only one star point reactor is grounded through a resistance to avoid unwanted earth circulating currents.

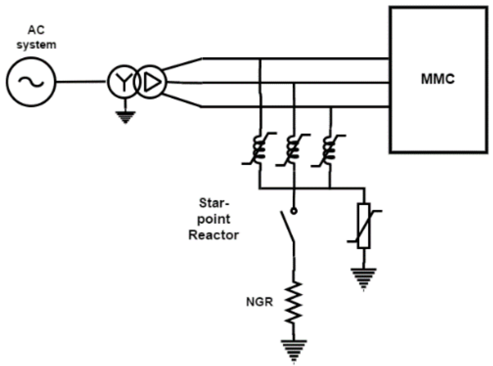


Figure 11-9: grounding at AC side using star point reactor for Symmetric Monopole

Bipolar configuration is grounded at the DC side of the converters. Figure 11-10 shows an example of grounding in case of point to point bipolar configuration with MR. The neutral point of the converter is solidly grounded or connected to ground via a surge arrester. In a point to point link as well as in a MTDC grid only one converter has the neutral point solidly grounded in order to avoid circulating currents through the ground.

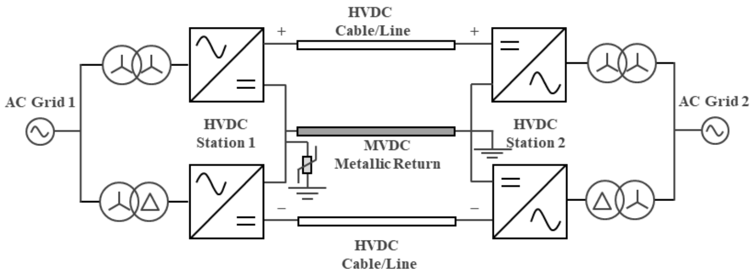


Figure 11-10: grounding at DC side for Bipole with MR

11.2.3. Power Flow

For all the simulations the considered initial power flow is shown in Figure 11-11. This particular power flow is chosen because no power is transmitted through the lines L23 and L45 connecting the three pre-existing point to point links. As a consequence, it will be possible to compare the impact of a fault on the network "GB + NL" with and without the extension to the network "GB + NL + DK" because the power flow in the part "GB + NL" will be the same. This power flow also respects the maximum allowed LoI condition for the three AC zones.

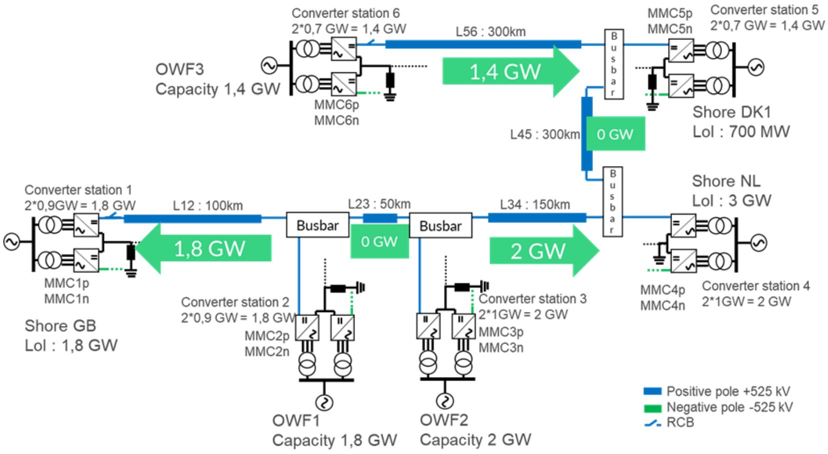


Figure 11-11: Studied power flow

11.3. EMTP-models

This section presents the main models used for the simulation performed with the EMTP-RV tool.

11.3.1. Cable

The cable is a wideband model built from the geometrical parameters shown in Table 11-2 and Table 11-3. For symmetrical monopole, two identical cables (core separated with 0,5m) are used within the same model. For Bipolar configuration, an additional cable is used as a metallic return. Cable screen is grounded at each end via a small resistance of 0.1Ω.

	Description	Value	Unit
Geometry	Core radius	32e-3	m
	Screen inner radius	56.9e-3	m
	Screen outer radius	58.2e-3	m
	Insulation radius	63.9e-3	m
Core resistivity	Core resistivity	1.72e-8	Ωm
	Screen resistivity	2.83e-8	Ωm

Table 11-2: Cable parameters for Monopolar and Bipolar configuration

	Description	Value	Unit
Geometry	Core radius	32e-3	m
	Insulation radius	38e-3	m
Resistivity	Core resistivity	1.72e-8	Ωm

Table 11-3: Metallic return parameters for Bipolar configuration

The cable frequency response of the resistance R (core ground loop) and inductance L (core ground loop) are shown in Figure 11-12. The cable core-ground capacitance response is 0.2416 μF/km, regardless of the frequency.

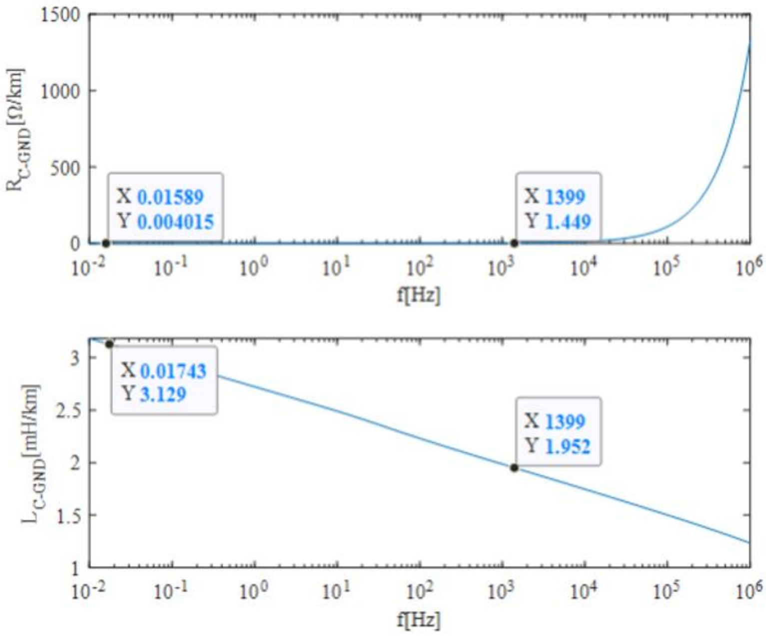


Figure 11-12: Cable frequency response of R (core ground loop) and L (core ground loop)

11.3.2. Fault

The fault is modelled using an ideal switch connecting pole to ground or pole to pole through a 10 mΩ fault resistance. Considering that most of the faults are due to the loss of the insulation between core and screen of the cable the choice of a low value of fault resistance is acceptable.

11.3.3. MMC station

Simulations have been performed with half bridge MMC. The model used is an average arm model, see Figure 11-13 (H. Saad, 2013).

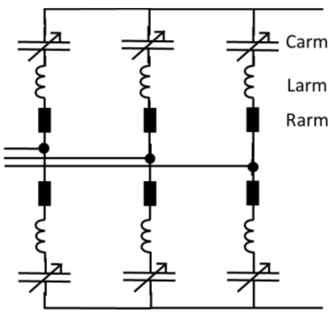


Figure 11-13: MMC half-bridge MMC model

MMC type	Pole to pole voltage	Description	Value
2 GW (Monopolar configuration)	1050 kV	Rarm Carm Larm	0,4 Ω 24,2 µF 65,8 mH
1.8 GW (Monopolar configuration)	1050 kV	Rarm Carm Larm	0,4 Ω 21,8 µF 73 mH
700 MW (Monopolar configuration)	1050 kV	Rarm Carm Larm	0,4 Ω 8,5 µF 188 mH
1 GW (Bipolar configuration)	525 kV	Rarm Carm Larm	0,4 Ω 48,4 µF 32.9 mH
900 MW (Bipolar Configuration)	525 kV	Rarm Carm Larm	0,4 Ω 43,5 µF 36,6 mH
700 MW (Bipolar configuration)	525 kV	Rarm Carm Larm	0,4 Ω 33,8 µF 47 mH

Table 11-4: MMC model parameters - Carm is the capacitance with all submodules inserted

The MMC converters are regulated using an energy based control system employing the virtual capacitor control for outer loop (Shinoda, K., Benchaib, A., Dai, J., and Guillaud, X., 2017) and a discrete-time controller for inner loops on currents (Zama A., Benchaib A., Bacha S., Frey D. and Silvant S., 2017) which allow high dynamic responses to power changes.

The MMC are connected to the perfect AC sources via a transformer connecting the AC system at 400 kVRMSLL to 525 kVRMSLL for monopolar configuration and from 400 kVRMSLL to 265 kVRMSLL for bipolar configuration. The transformers have Yn/Δ windings, as can be seen on Figure 11-14 and their model parameters can be found on table Table 11-5.

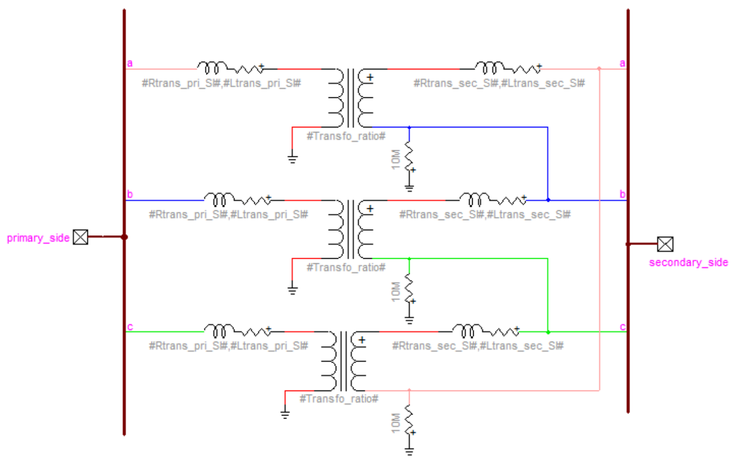


Figure 11-14: Transformer model

Converter station type	Secondary AC voltage	Description	Value	Unit
2 GW (Monopolar configuration)	525 kVRMSLL	Rtrans_pri Ltrans_pri Rtrans_sec Ltrans_sec	0,072 0,0412 0,0138 0,0079	Ω H Ω H
1,8 GW (Monopolar configuration)	525 kVRMSLL	Rtrans_pri Ltrans_pri Rtrans_sec Ltrans_sec	0,08 0,0458 0,0153 0,00877	Ω H Ω H
700 MW (Monopolar configuration)	525 kVRMSLL	Rtrans_pri Ltrans_pri Rtrans_sec Ltrans_sec	0,206 0,118 0,0394 0,0226	Ω H Ω H
2*1 GW (Bipolar configuration)	265.5 kVRMSLL	Rtrans_pri Ltrans_pri	0,144 0,0825	Ω H

		Rtrans_sec Ltrans_sec	0,00689 0,00395	Ω H
2*900 MW (Bipolar Configuration)	265.5 kVRMSLL	Rtrans_pri Ltrans_pri Rtrans_sec Ltrans_sec	0,16 0,0917 0,00766 0,00439	Ω H Ω H
2*700 MW (Bipolar configuration)	265.5 kVRMSLL	Rtrans_pri Ltrans_pri Rtrans_sec Ltrans_sec	0,206 0,118 0,00984 0,00564	Ω H Ω H

Table 11-5: Transformer parameters

11.3.4. DC circuit breakers

Two types of DC circuit breakers are used in simulations; mechanical DC circuit breakers are employed within the non-selective fault clearing strategy and hybrid DC circuit breakers are employed within the fully selective fault clearing strategy. Both breakers are modelled with an ideal switch (SW1) in parallel with a capacitor and a surge arrester, see Figure 11-15, as proposed within PROMOTioN Project WP6 (PROMOTioN Workpackage 6, 2016) (PROMOTioN Workpackage 6, 2016) (PROMOTioN Workpackage 6, 2018). Breakers parameters are shown in Table 11-6. The SW1 opens with an opening delay depending on the breaker type, 2 ms for the hybrid breaker and 15 ms for the mechanical breaker. The SW2 represents the residual current breaker (RCB) which opens with an opening delay of 10 ms if the current is lower than 10 A. The RCB is opened just after the fault clearing to eliminate the residual current and to isolate the faulty line from the healthy part of the grid (PROMOTioN Workpackage 6, 2018).

	Description	Value
Mechanical DC circuit breaker	Opening delay C	2 ms 1.6 µF
Hybrid DC circuit breaker	Opening delay C	15 ms 16 µF

Table 11-6: DCCB parameters

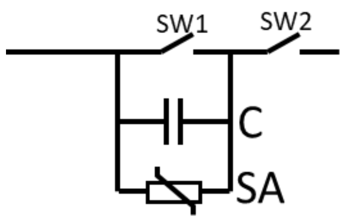


Figure 11-15: DCCB model

11.3.5. Surge arrester

The surge arrester (SA) voltage-current characteristic modelled within the DCCB as well as the line SA is shown in Figure 11-16.

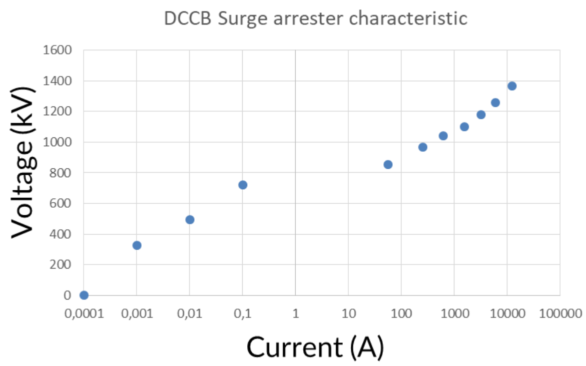


Figure 11-16: voltage-current characteristic of SA

11.3.6. Pole rebalancing devices

After a pole to ground fault in monopolar configuration, the faulted pole voltage drops and the unfaulted pole rises to high overvoltage (even more than 2pu). As a consequence, a voltage rebalancing procedure is necessary to restore the system. Rebalancing of the voltage can be realized in several manner (Wang, Leterme, Chaffey, Beerten, & Van Hertem, 2019), (A. Bertinato, P. Torwelle, et. al., 2019); in this study two type of voltage rebalancing equipment are studied:

- Dynamic Braking Resistor (DBS)
- Pole Rebalancing Reactor (PRR)

11.3.6.1. Pole rebalancing reactors

Pole rebalancing reactor is a pole rebalancing device connected on the AC side of the MMC. The aim of the PRR is to provide a low impedance zero sequence path to ground to allow the charging/discharging of the cable stray capacitances of the poles. The model of the pole rebalancing reactor is described in Figure 11-18. In the simulations, two sets of values are used for the inductor and resistor:

- L = 1 H and R = 10 Ω if the cable length to be rebalanced is longer than 150 km
- L = 1 H, R = 1000 Ω if the cable length to be rebalanced is 150 km or shorter

In case of short cables the stray capacitance is lower, as a consequence the dynamics of the recharge must be damped with higher value of resistor in order to reduce voltage oscillations and overshoots.

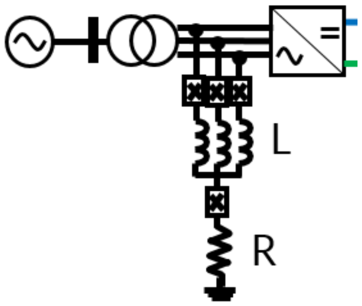


Figure 11-17 : Pole Rebalancing Reactors

11.3.6.2. Dynamic breaking system

The dynamic breaking system is a pole rebalancing device based on power electronic components to be connected to the DC side of the MMC. Several types of DBS topologies have been proposed in literature (Wang, Leterme, Chaffey, Beerten, & Van Hertem, 2019); the Figure 11-18 shows the DBS topology that has been used during the simulations. Each pole is connected with its DBS. The dynamic of the DBS control is set with a time response of around 3 ms.

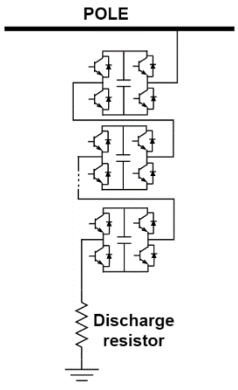


Figure 11-18: DBS circuit topology

11.3.6.3. Pole rebalancing device location

When a line is faulted, the fault is isolated by the protection devices. As a consequence, the network should be restored as separate subnetworks, and several pole rebalancing devices are required in order to be able to restore power in the subnetworks. Due to the footprint and installation considerations, it is better to install the pole rebalancing devices onshore. Taking into account those concerns, the best places to install the pole rebalancing devices would be close to converter stations 1, 4 and 5, see Figure 11-19 and Figure 11-20.

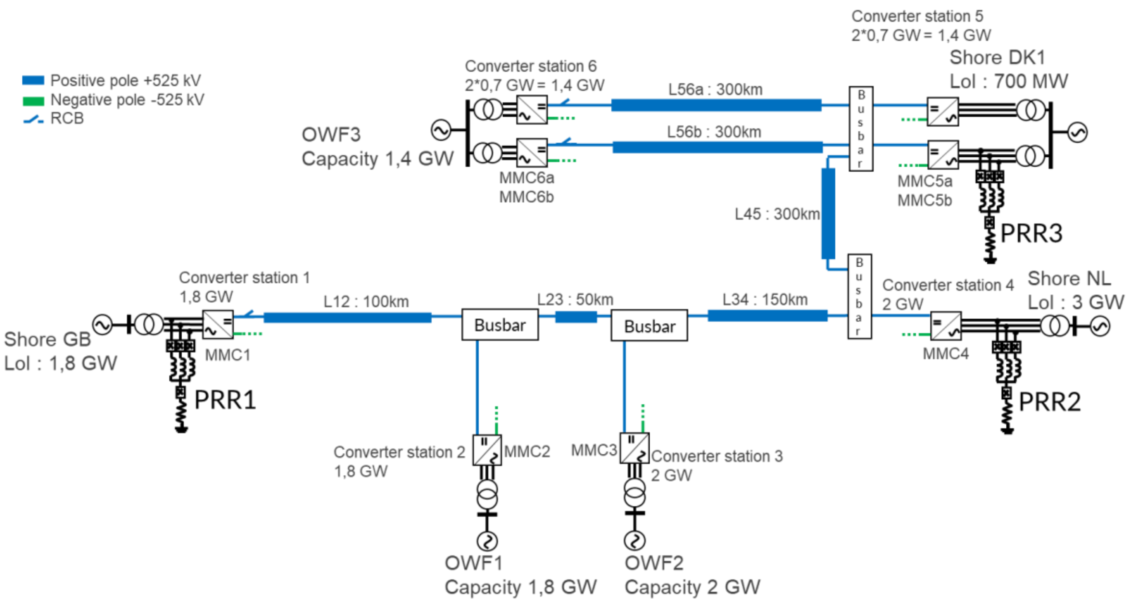


Figure 11-19: Proposed PRR location for NS strategy

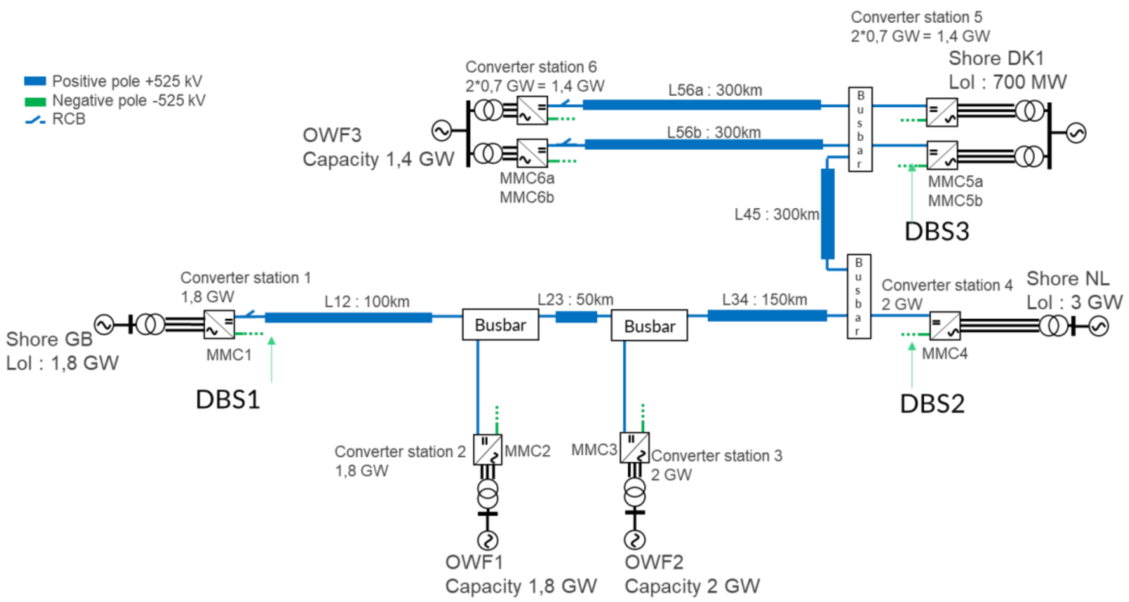


Figure 11-20: Proposed DBS location for FS strategy

11.3.7. AC side

In all simulations performed, the AC side of the MMC is modelled by a 400 kV rms AC source, see parameters on Table 11-7.

	Description	Value
AC source	AC voltage	400 kVRMSLL
	AC frequency	50 Hz

	Scc	10 000 MVA

Table 11-7: AC source parameters

11.3.8. Wind farm models

Two models of wind farms had been considered in this study. The first model is an ideal AC source in series with a short circuit impedance as proposed in PROMOTioN WP4 (PROMOTioN Workpackage 4, 2017). The second model, explained hereunder, is a more detailed model that takes into account the behaviour of the Fully Fed generator connected to the wind turbine. Figure 11-21 shows the main components of an HVDC system connected to an OWF. Defining the control for each component of the grid is mandatory to understand the behaviour during DC fault.

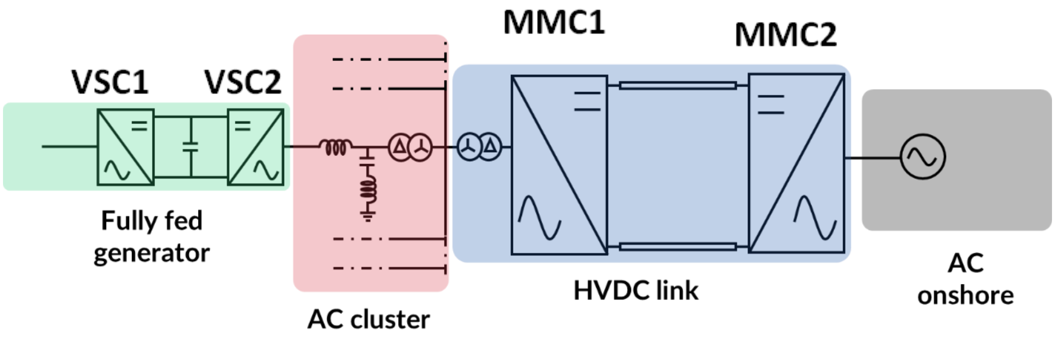


Figure 11-21: Main component of HVDC system connected to an OWF

The control mode employed for the OWF connection is as following:

- VSC1: Power control based on MPPT
- VSC2: DC voltage control to transfer power to the AC collector
- MMC1: V/F control to create a voltage reference for AC cluster
- MMC2: DC voltage control of HVDC link

A crowbar resistance is installed at the DC side of VSC1 in order to limit the overvoltage in case of power interruption at VSC2 side (e.g. of FRT). The crowbar resistance is supposed to be designed to act for 150-300 ms. After that other actions (e.g. pitch control) need to be taken. In case of DC fault located on the HVDC link, MMC1 and MMC2 block theirs pulses signals to protect their IGBTs and behave similarly as a diode bridge rectifier. The VSC1 keeps sending power to the DC bus which increases its voltage; once the voltage achieves a given value the crowbar system is activated to limit the DC bus voltage. At the same time the VSC2 is controlled to limit its reactive current output (e.g. 1.2-1.5 pu) in order to prevent damages of power electronic components. Prefault AC voltage references are kept in memory to keep the control of VSC2 (< 100-200 ms). The fully fed generator is modeled with a 2-level converters. To release simulation constraints several wind turbine generators are aggregated into one single model.

The simulation cases presented in this study use the first simple model (ideal AC source) excepted for the simulation of the case 5 (section 11.5.6) where the aim is to see the impact of OWM models on the short circuit output.

11.3.9. Virtual mock-up

In order to perform the EMT simulations a virtual mock-up has been created within EMTP-RV, see an example in Figure 11-22 . The virtual mock-up is a system integration of converter models and controls, cables, protection equipment, voltage rebalancing equipment and protection algorithms in an EMTP work project. The virtual mock up allows to perform several fault case scenarios for different protection strategies taking into account possible grid extensions.

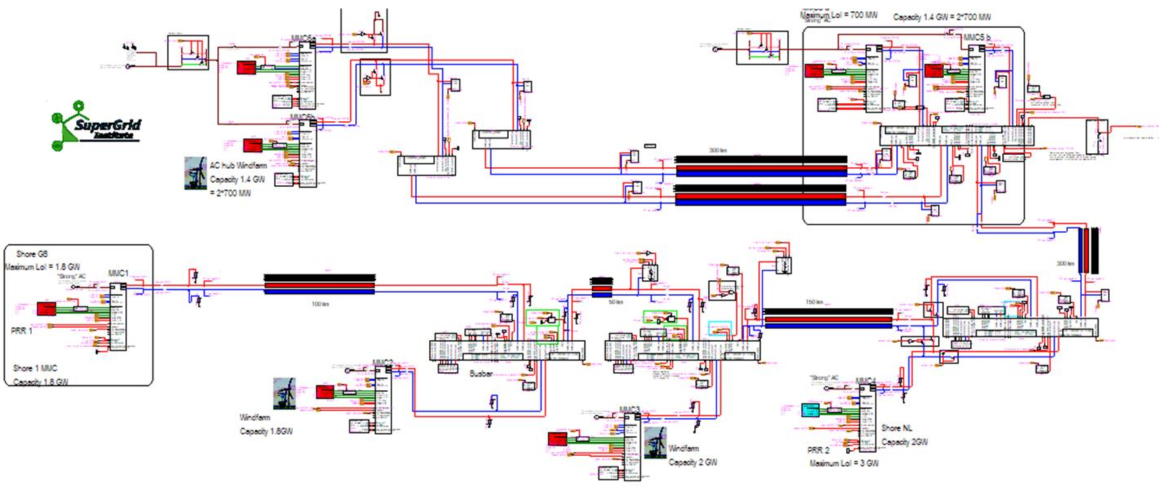


Figure 11-22: Example of EMTP-RV virtual mock-up

In order to ease the integration of the models on the virtual mock-up, only the symmetric monopolar configuration has been realized. As explained in section 11.2.2.3 the symmetric monopole can be used to study:

- Sustained overcurrents during pole to pole fault. It should be noted that overcurrents on bipole during pole to ground fault can be considered equal to overcurrents on a symmetric monopole during pole to pole fault.
- Sustained overvoltages and non-sustained overcurrents during pole to ground faults.

11.4. Protection strategies

This chapter will presents the simulated network, the single line diagram and the sequences for the understanding of the two protection strategies. The list of simulations to be carried out and the justification for their choice will also be presented at the end of the chapter.

11.4.1. Choice of busbar configuration

In order to define the components and layout of a protection strategy, it is necessary to first define a busbar configuration. To make a first selection of DC busbar configuration a qualitative security analysis shown in Table 11-8 has been made considering the following faults and failure:

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

From Table 11-8, it can be seen that the busbar configuration has a main impact on the security operation of the DC grid in particular when looking at busbar fault and line fault + 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. Same faults on a Double Busbar Single Breaker (DBSB) configuration would entail a temporary stop for both FS and NS strategies. On a Double Busbar Double Breaker (DBDB) configuration those faults would entails temporary stop in case on NS strategy but "Continuous Operation" in case of FS strategy.
For FS fault clearing strategies DBDB is therefore the chosen configuration option because it allows "Continuous Operation". It should be noted however that even in "Continuous Operation" there could be power oscillations on DC side during the fault recovery.
For NS fault clearing strategies DBSB configuration is the chosen option. It should be noted that the use of NS strategies implies that temporary stop of power (higher than maximum LoI) is allowed. It is also assumed that busbar reconfiguration time is automatic and fast (<100 ms) and it is "hidden" within the intrinsic temporary stop of the NS fault clearing strategy.

	Full selective Strategy			**Non Selective Strategy**		
	Line Fault	Busbar Fault	Line fault + breaker failure	Line Fault	Busbar Fault	Line fault + breaker failure
Single busbar single breaker	"Continuous Operation"	Permanent Stop	Permanent Stop	Temporary Stop	Permanent Stop	Permanent Stop

Double busbar single breaker	"Continuous Operation"	Temporary Stop	Temporary Stop	Temporary Stop	Temporary Stop	Temporary Stop
Double busbar double breaker	"Continuous Operation"	"Continuous Operation"	"Continuous Operation"	Temporary Stop	Temporary Stop	Temporary Stop

Table 11-8 Qualitative security analysis for busbar configuration choice

11.4.2. Full selective fault clearing strategy

The DBDB configuration considered for a selective protection strategy is shown in Figure 11-23 for a generic node. Each feeder (or line) is connected to a DCR and through the two busbars by means of two DCCBs. In normal operation both breakers are connected in order to energize the two busbars BB1 and BB2.

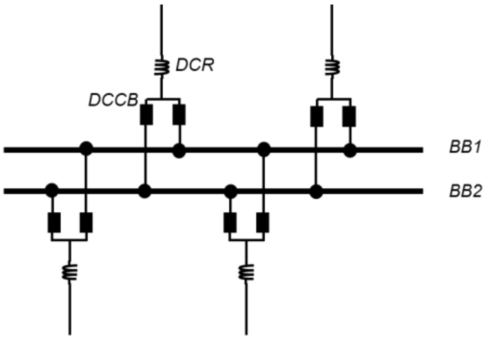


Figure 11-23: Busbar configuration for FS strategy

The fault clearing sequences, time-line and breaker actions for three type of faults are presented in the following sections (11.4.2.1, 11.4.2.2 and 11.4.2.3). Those fault clearing sequences are valid for both bipolar (pole to ground fault) and monopolar configurations (pole to ground and pole to pole fault). In case of monopolar configuration and pole to ground fault a voltage rebalancing sequence needs also to be performed as presented in section 11.4.2.4.
A preliminary hypothesis of technical specification for DCCB and DCR to be used in the FS strategy is shown in Table 11-9.

Input parameter	Unit	FS - FDCCB
Technology		Hybrid
Rated DC current	kA	1,5
Rated Breaking current capability	kA	15
Rated DC voltage	kV	525
Rated transient Interruption Voltage (TIV)	p.u	1.5
Rated energy absorption	MJ	47
Breaker opening time at maximum DC breaking current	ms	2
Current limiting DC reactor	mH	50 - 140
Open-close operation	-	O

Directionality	-	Bi-directional
Rated short time withstand current	kA	16

Table 11-9: Technical specification for DCCB and DCR in FS strategy

11.4.2.1. Sequence in case of line fault

In case of a line fault, both breakers need to open in order to isolate the fault. The primary fault sequence is shown in Figure 11-24 and Figure 11-25 while the time sequence of the fault clearing is depicted in Figure 11-26. After fault clearing, both busbars will remain in operation and can resume the power.

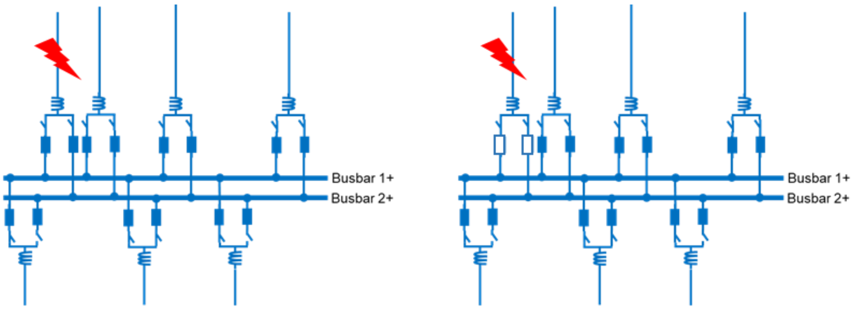


Figure 11-24: Full selective fault clearing strategy, breaker actions for a line fault

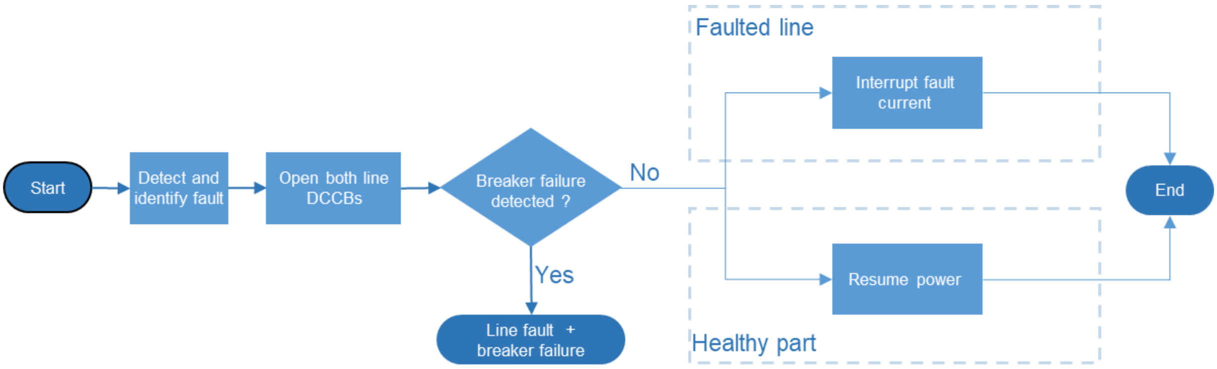


Figure 11-25: Full selective fault clearing strategy sequence for a line fault

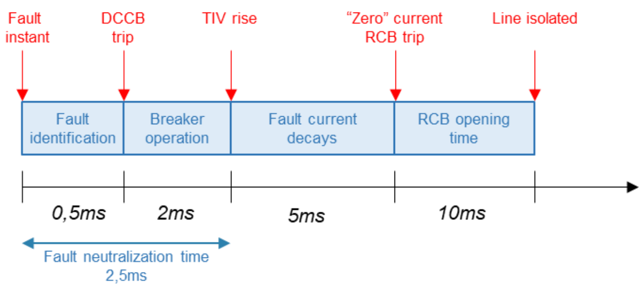


Figure 11-26: Full selective fault clearing strategy time-line for a line fault

11.4.2.2. Sequence in case of line fault and breaker failure

The backup sequence in case of line fault and a breaker failure is shown in the following Figure 11-27, Figure 11-28 and Figure 11-29. After detection of the breaker failure, all the adjacent breakers connected to the same busbar need to be opened in order to clear the fault. After fault clearing, the busbar connected with the healthy breakers will remain in operation and can resumes the power.

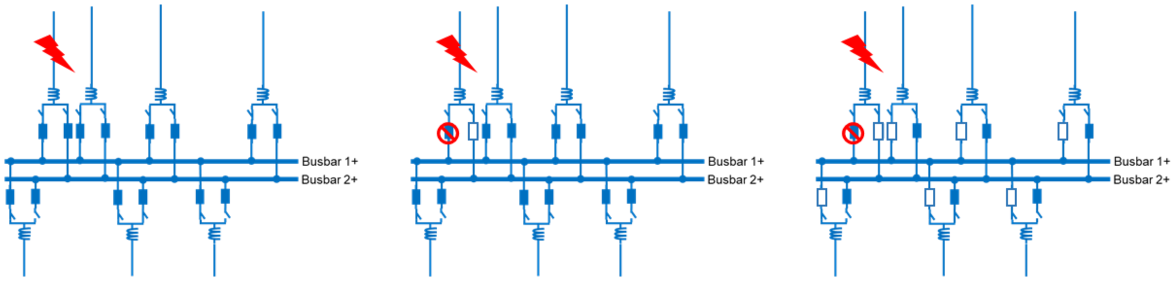


Figure 11-27: Full selective fault clearing strategy, breaker action for backup

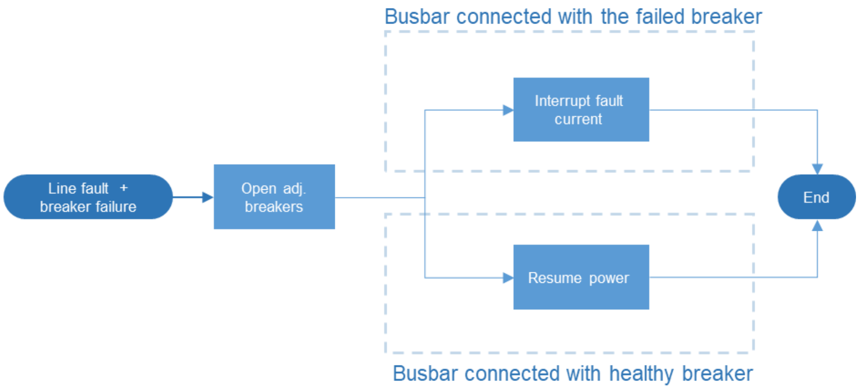


Figure 11-28: Full selective fault clearing strategy for backup

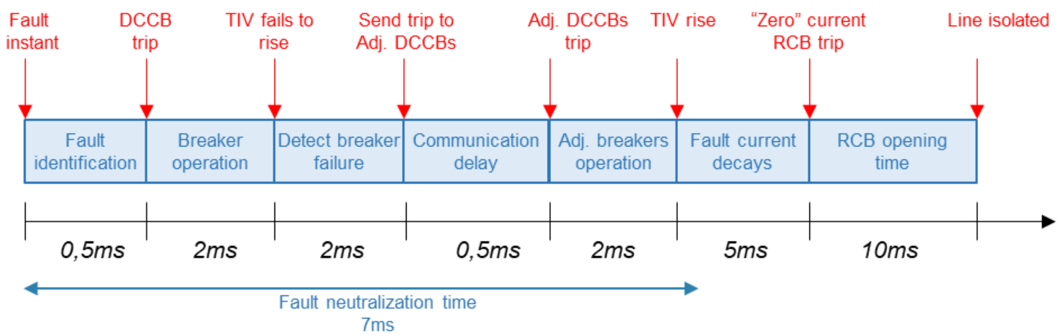


Figure 11-29: Full selective fault clearing strategy time-line for backup

11.4.2.3. Sequence in case of busbar fault

In case of busbar fault it is necessary to open all the breakers connected to the faulty busbar. Thanks to the busbar configuration the healthy busbar can resume the power flow.

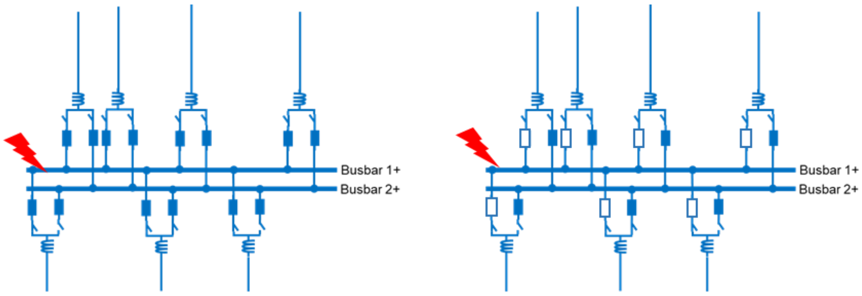


Figure 11-30: Full selective fault clearing strategy, breaker actions for a busbar fault

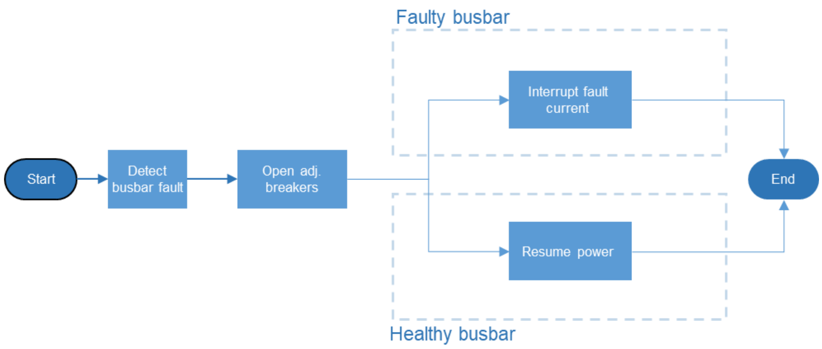


Figure 11-31: Full selective fault clearing strategy, busbar fault sequence

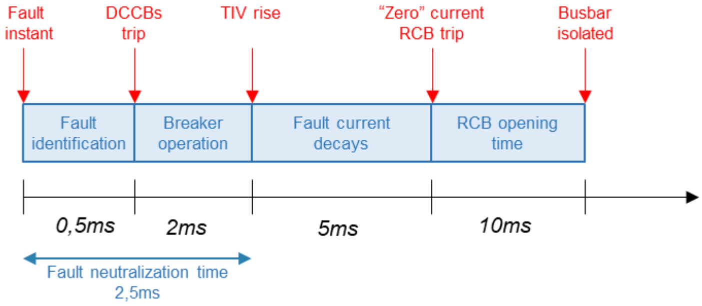


Figure 11-32: Full selective fault clearing strategy, busbar fault time-line

11.4.2.4. Voltage Rebalancing sequence

In case of monopolar configuration and pole to ground fault, after the fault clearing it is necessary to perform actions in order to rebalance the pole to ground voltages. For the full selective strategy the voltage is rebalanced by means of a DBS; the sequence is shown in Figure 11-33.

Figure 11-33: Full selective fault clearing strategy, voltage rebalancing sequence using DBS

11.4.3. Non selective fault clearing strategy

The DBSB configuration considered for a non-selective protection strategy is shown in Figure 11-34 for a generic node. Each feeder (or line) is connected to a DCCB and through the two busbars by means of two RCBs that have also the function of high speed switches for the busbar reconfiguration. In normal operation the breakers are connected to only one busbar while the busbar coupler (BC) is in closed position in order to energize the two busbars BB1 and BB2. A DCR is installed in series of the BC in order to limit the first peak of the Short Time Current (STC) due to the discharge of the cables.

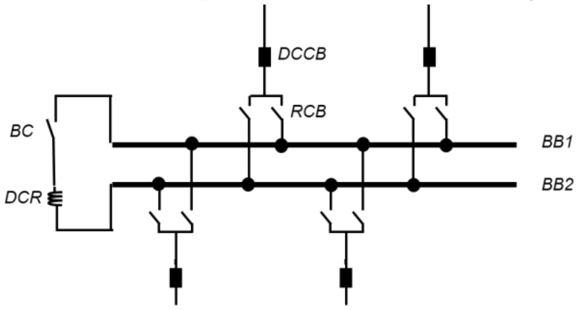


Figure 11-34: Busbar configuration for NS strategy

The sections 11.4.3.1, 11.4.3.2, 11.4.3.3 and 11.4.3.4 explain the protection sequences for the non-selective fault clearing strategy in case of pole to ground fault in a bipolar configuration. The sequences are considered to be the same in case of pole to pole fault in a symmetric monopolar configuration. The section 11.4.3.5 describes the fault clearing and the voltage rebalancing sequence in case of a pole to ground fault in a symmetric monopolar configuration.
A preliminary hypothesis of technical specification for DCCB and DCR to be used in the FS strategy is shown in Table 11-10.

Input parameter	Unit	FS - FDCCB
Technology		Mechanical
Rated DC current	kA	1.5
Rated Breaking current capability	kA	20
Rated DC voltage	kV	525
Rated transient Interruption Voltage (TIV)	p.u	1.5
Rated energy absorption	MJ	10-20 MJ
Breaker opening time	ms	15
Current limiting DC reactor	mH	0 mH in lines + 10 mH in bus coupler (to limit STC)

Open-close operation	-	O – 60 ms - C - O
Directionality	-	Bi-directional
Rated short time withstand current	kA	40 kA

Table 11-10: Technical specification for DCCB and DCR in FS strategy

11.4.3.1. Sequence in case of line fault

In case of a line fault all converter breakers need to open in order to isolate the fault. The primary fault sequence is shown in Figure 11-35 while the time sequence of the fault clearing is depicted in Figure 11-36. It should be noted that after fault arrival and before DCCB breaker opening, MMC converters are rapidly blocked and the AC contribution to the fault passes through the freewheeling diodes. During this period, a fault identification algorithm can be operated to discriminate the faulty line. After converter breaker opening, the MMC can be deblocked and converters can be used as STATCOM to sustain the AC voltage by injecting reactive power into the grid. The faulty line isolation starts after the operation of the fault identification algorithm and it is performed by the line breakers. The reason to use line breakers instead of more simple high speed switches relies on their breaking capability, required in order to accelerate the protection sequence in case of a converter breaker failure. After the faulty line is isolated, the converter breakers reclose and the grid voltage restoration begins. The reclosing order is sent independently to each converter breaker after a fixed delay, called "reclosing time", has been elapsed. The reclosing time, here set to 60ms, needs to be long enough to ensure that the faulty line isolation has been performed, even in case of a breaker failure backup sequence. After voltage recovery the power can be restored by setting a power ramp up reference for all the MMC converters.

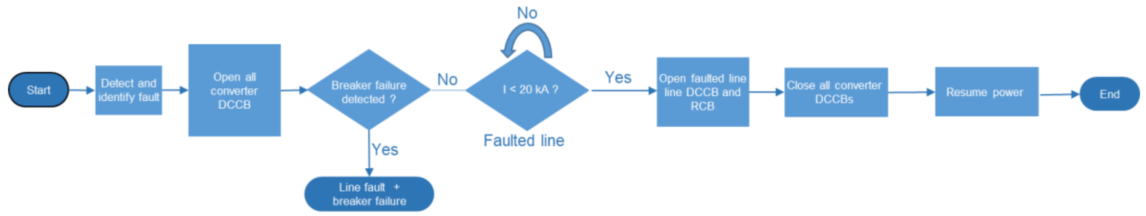


Figure 11-35: Non selective fault clearing strategy for a line fault

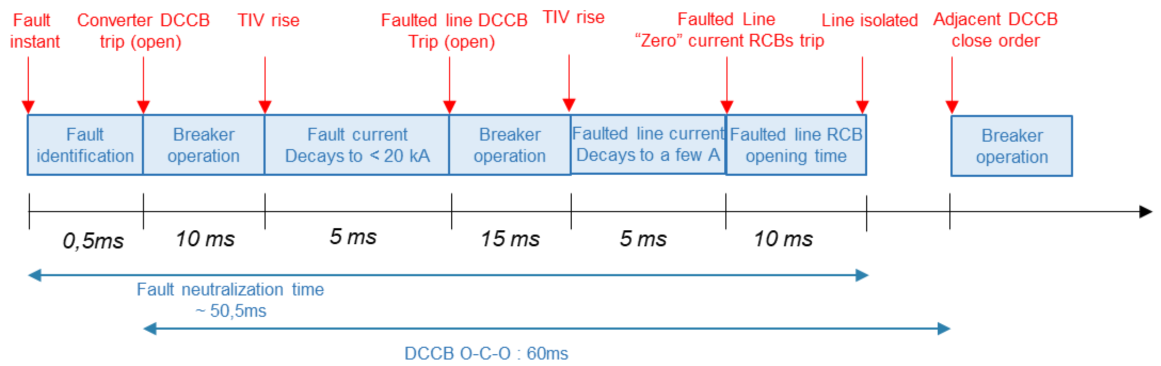


Figure 11-36: Non selective fault clearing strategy time-line for a line fault

11.4.3.2. Sequence in case of line fault and line breaker failure

In case of line breaker opening failure the sequence is the same as for the primary sequence. Indeed, even if a line breaker fails to open, the fault current is still cleared by the converter breaker. The RCB associated to the failed line breaker will open when the RCB opening conditions are ensured and it will isolate the faulty line.

11.4.3.3. Sequence in case of line fault and converter breaker failure

In case one converter breaker fails to open, its associated MMC converter remains blocked and maintains the contribution to the fault current. However, because of the disconnection of N-1 converters stations (where N is the number of stations on the DC grid) the fault current does not reach the line breaker current capability and the breaker opening of faulty line can still be performed. Once the fault current is close to zero, the RCB in series with the failed converter breaker is able to open and isolate the converter from the grid. The healthy part of the grid is thereafter ready to restart the power flow.

11.4.3.4. Sequence in case of busbar fault

A busbar fault is treated similarly as a line fault, see Figure 11-36, with the exception that after the opening of all converter breakers, the faulty busbar need to be identified and an opening trip need to be sent to all breakers connected to the faulty busbar. In a second step, a reconfiguration process need to be taken in order to isolate the faulty busbar by opening the busbar coupler and the high speed switches connected to the faulty busbar. At the end, the converter breaker can be reclosed and the power restored.

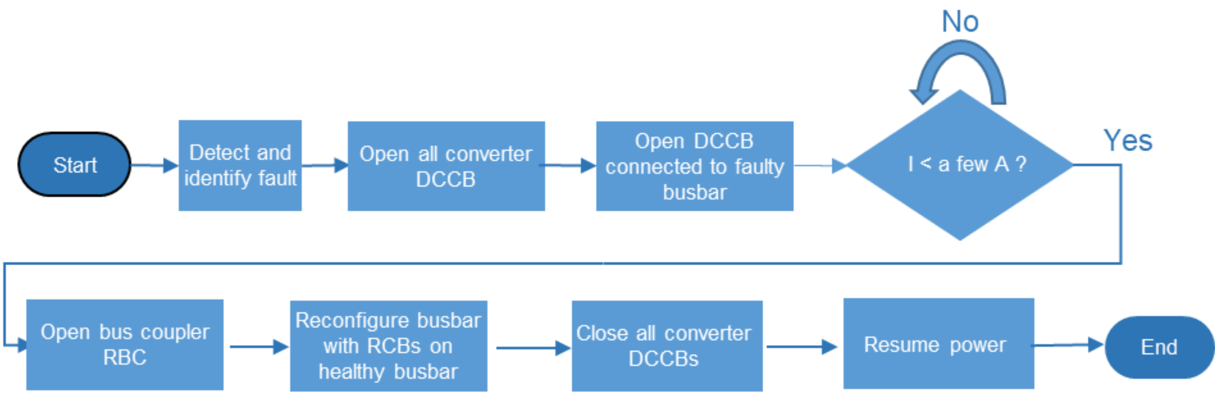


Figure 11-37: Non selective fault clearing strategy for busbar fault

11.4.3.5. Sequence in case of pole to ground fault in a symmetric monopolar

The sequence for the management of a pole to ground fault in a symmetric monopole using a non-selective strategy is shown in Figure 11-38. The non-selective fault clearing is carried out by the blocking of all the MMCs. Due to the type of fault (pole to ground) and the high impedance system grounding at AC side, by blocking the MMCs the fault current will be automatically reduced to zero (A. Bertinato, P. Torwelle, et. al., 2019). In the meanwhile the faulty line is identified and the line breakers can be opened. The

PRR can successively be connected in order to rebalance the voltage of DC grid. A PRR connection delay is necessary in order to avoid the connection of the PRR before the faulty line isolation. Once the voltage is rebalanced the MMCs can be de-blocked and the power restored. In case of malfunctioning of the pole rebalancing device the voltage of the healthy pole would remain at a voltage close to the threshold voltage of the line SA and the energy would keep flowing through the SA. A possible backup could be the opening of all AC breakers in order to avoid the risk of damaging of the SA due to thermal stress. Nevertheless such backup would entail a temporary stop of the entire grid of few seconds.

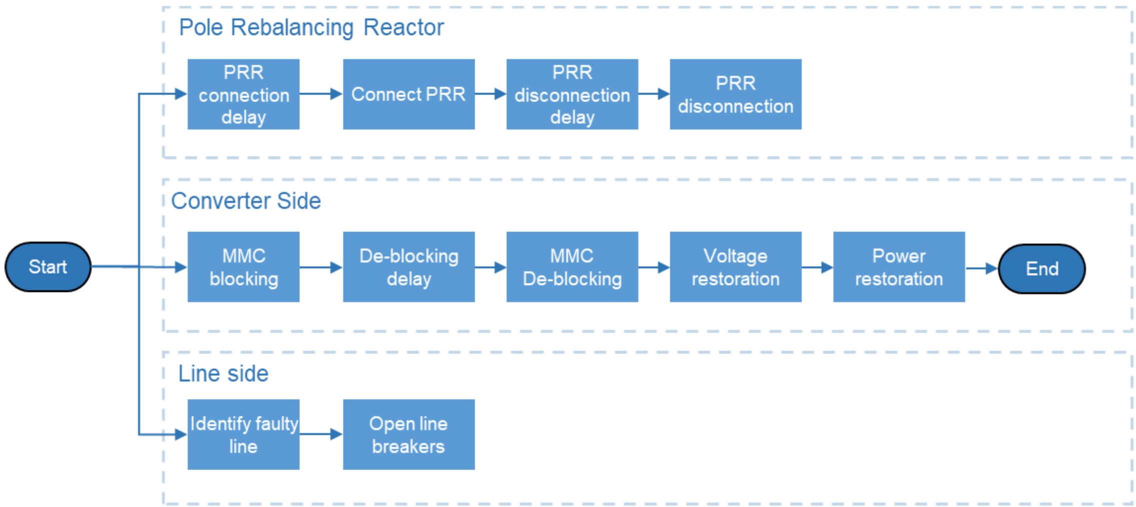


Figure 11-38: Non selective fault clearing strategy and rebalancing sequence for pole to ground fault in symmetric monopole

11.5. Performed simulations and results

As already mentioned, it is not the focus of this study to perform a big amount of simulations considering all possible fault cases, protection strategies and benchmark grids. In contrast, an expert selection of fault scenarios has been carried out during the follow up meetings between SuperGrid Institute and Tractebel. It has been decided to focus on the impact that a grid extension could have on the design of the protection equipment. For all simulations the considered grid extension is the extension "2" where the MTDC grid "GB + NL" is connected to the point to point link "DK1" through L45, see section 11.2.1 and Figure 11-4. The Table 11-10 resumes the simulated scenarios and presents the expectations for each scenario.

Case	Protection Strategy	Config.	Type of fault	Focus
1	NS	Bipole*	Pole to Ground	Primary Sequence. Fault on line L23 close to station 3. Impact of the extensibility on the design of the converter breaker of station 3 in term of breaking capability and energy to be dissipated.
2a	NS	Symm. Mon.	Pole to Ground	Primary sequence. Fault on line L23 close to station 23. Impact of the extension on the design of the surge arresters and on the design of rebalancing device.
2b	NS	Symm. Mon.	Pole to Ground	Busbar fault. Impact of short time current on the design of the DCCB and busbar coupler.
3	FS	Bipole*	Pole to Ground	The aim is to check the impact of the extension on the rating of DCCB 34 connecting station 3 with line L34 considering primary and backup sequence. For primary sequence, fault on line L34 close to station 3. For breaker failure backup the fault is considered on line L23 close to station 3. The failed breaker is DCCB 23 therefore DCCB 34 need to clear the fault. Different values of DCR are considered (50 mH and 140 mH).
4	FS	Symm. Mon.	Pole to Ground	Primary sequence. Fault on line L23 close to station 23. Impact of the extension on the design of the surge arresters and on the design of rebalancing device.
5	n.a.	Bipole*	Pole to Ground	Primary sequence. Impact of WF modelling on the short circuit currents and technical challenges related to WF modelling.
6	n.a.	Symm. Mon.	Pole to Pole	Impact of a breaker failure on the energy absorption of the healthy breaker.

Table 11-11: Simulated Scenarios

(*) Results of sustained overcurrent are comparable for the case of Symmetric Monopole and pole to pole fault.

11.5.1. Case 1

In this case the simulations are performed for bipolar configuration and pole to ground fault. The primary and backup sequences of NS fault clearing strategy are presented in detail in section 11.4.3 and 11.4.2. The aim of this simulation is to check the impact of the grid extension on the rating of the converter breakers (current breaking capability and energy requirements). The DCCB under consideration is the converter breaker connecting station 3 as well as the line DCCB 32, connecting station 3 with the line 23. Figure 11-39 shows the fault location for the grid before (a) and after extension (b). Table 11-12 shows the calculated peak current and estimated energy requirement for converter breakers DCCB 3 and line breaker DCCB 32. Figure 11-40 and Figure 11-41 show the current evolution for DCCB 3 (a) and DCCB 32 (b) before extension (red) and after extension (blue) for primary sequence and backup sequence. It can be seen that the extension of the grid has a major impact on the short time let through current of the line breaker. Adding lines and converters increases the current through the breaker as well as the tripping time of the breaker. The higher constraints happen during the backup; in this case the fault clearing time of the line breaker increases because the trip order is sent after the line current is lower than its breaking capability, e.g. 20 kA in this case.

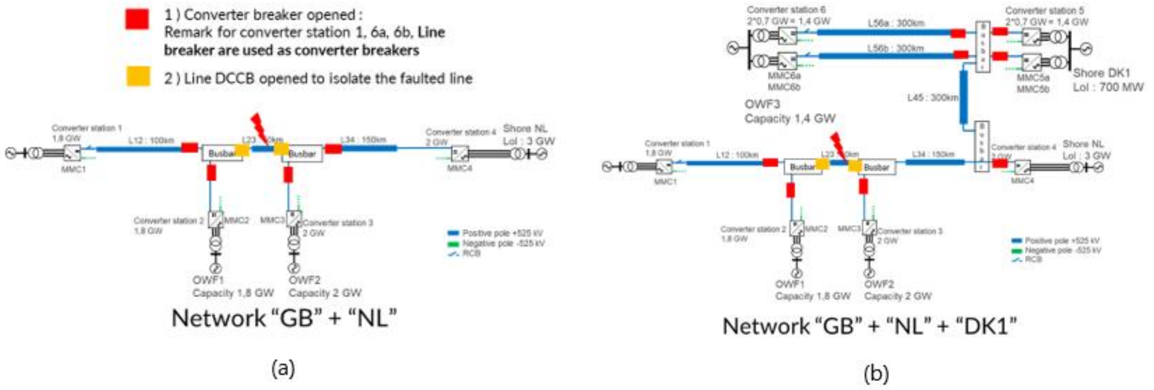
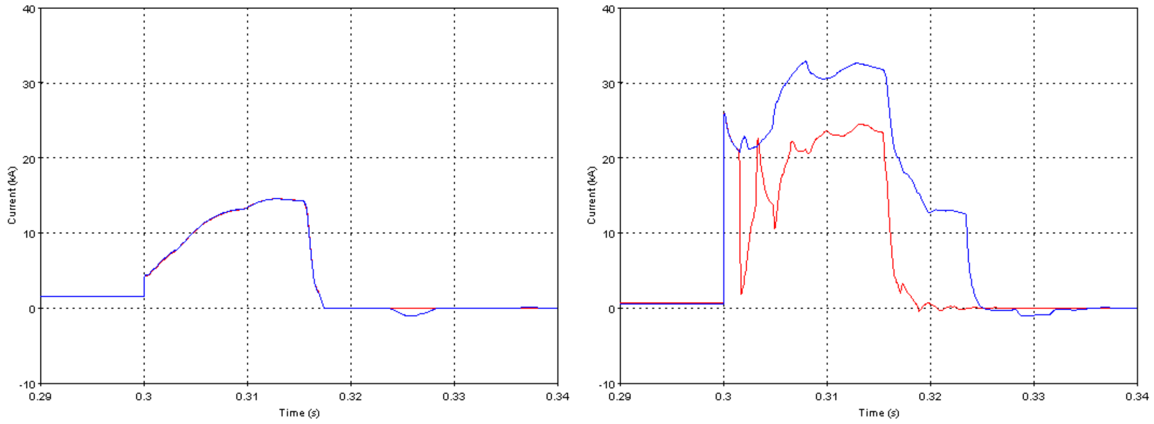


Figure 11-39: fault location for Case 1

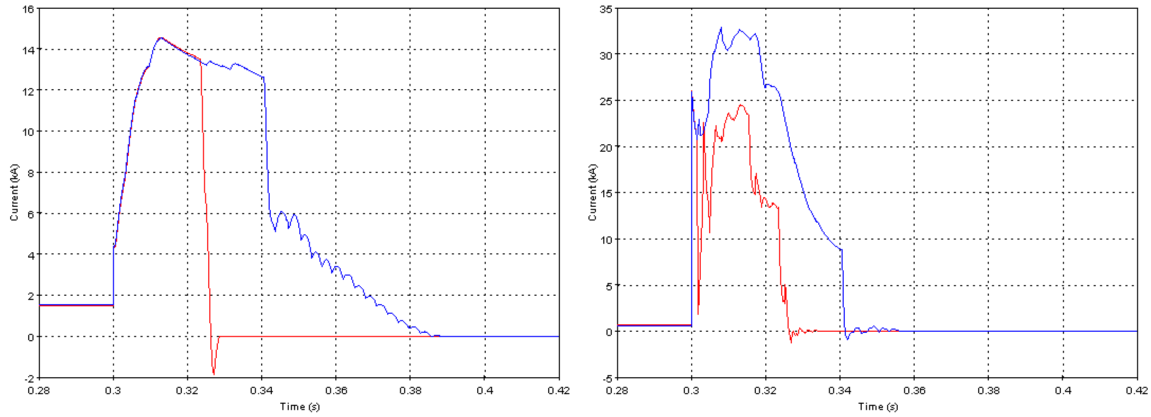
Network	Before extension: “GB” + “NL”		After extension: “GB” + “NL” + “DK1”	
DCCB	Converter DCCB 3	Line DCCB 32	Converter DCCB 3	Line DCCB 32
Primary sequence	14,3 kA ; 1,7 MJ	~0 kA ; ~0 MJ	14,2 kA ; 1.2 MJ	~0 kA ; ~0 MJ
Backup sequence	n.a. ; 0 MJ	20 kA ; 1,4 MJ	n.a. kA ; 0 MJ	20 kA ; ~ 0 MJ

Table 11-12: Calculated peak current to be cleared and estimated energy for converter DCCB 3 and line DCCB 32



(a) (b)

Figure 11-40: current on converter breaker (a) and line breaker (b) before extension (red) and after extension (blue) for primary sequence



(a) (b)

Figure 11-41: current on converter breaker (a) and line breaker (b) before extension (red) and after extension (blue) for backup sequence

<u>General findings:</u>

From the analysis of this particular some observations can be made:

- The converter breaker never see a current higher than the contribution coming from its related converter, independently from the protection sequence (primary or backup) and the extension of the grid. Therefore, extending the network doesn’t change significantly the ratings for the converter breakers.
- Line breaker needs to be design with a short time let through current that depends on the extension of the grid. If the short time current becomes too high (e.g. higher than constraints imposed by electric components), a limiting inductor could be necessary in order to reduce this value.
- The extension of the grid seems to have low impact on the energy requirement of the breakers.

11.5.2. Case 2a

The simulations are performed for symmetric monopolar configuration and pole to ground fault. The fault location is on line L23, positive pole, close to station 23. The aim here is to analyse the impact of the extension on the design of the surge arresters and on the design of rebalancing devices. The NS strategy for pole to ground fault in a symmetric monopole is explained in detail in section 11.4.3.5. The employed pole rebalancing reactors, installed as shown in section 11.3.6.3, are those on station 1 and station 4. Lines are protected with SA as shown in Figure 11-42. SA are designed in order to limit the overvoltage of healthy pole at around 1.4 pu. The voltage current characteristic of the SA is presented in section 11.3.5. Voltage rebalancing before and after grid extensions are shown in Figure 11-43 and Figure 11-44 respectively. Table 11-13 shows the energy (min and max) to be dissipated by the SA before and after the extension. It can be seen that energy decreases after grid extension, this is due to the fact that after extension there are more SAs compared to the increasing of the stray capacitance of the cables.

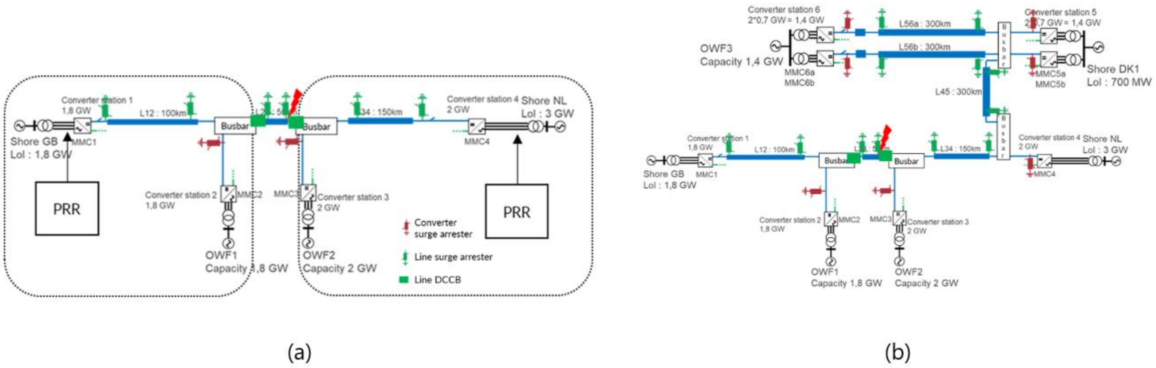


Figure 11-42: Surge arrester placement before (a) and after grid extension (b)

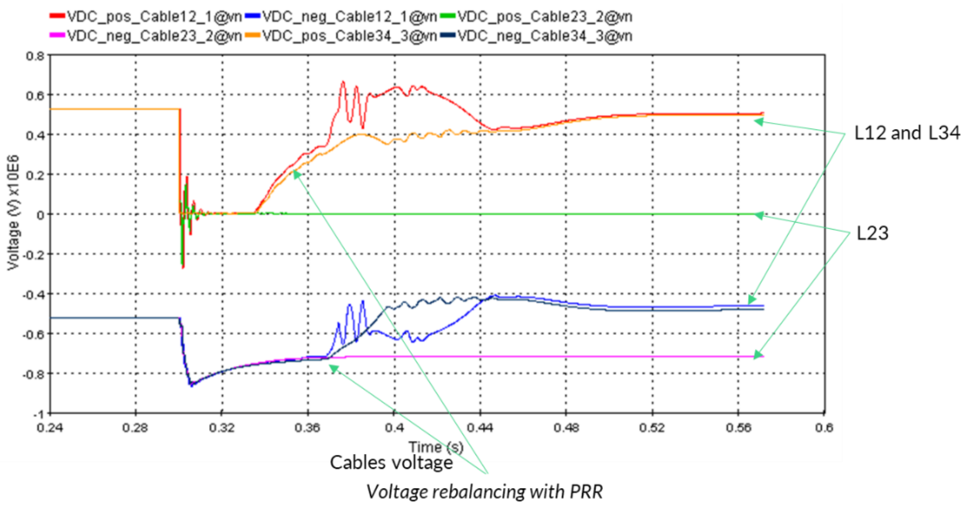


Figure 11-43: Pole to ground fault sequence for the grid before extension.

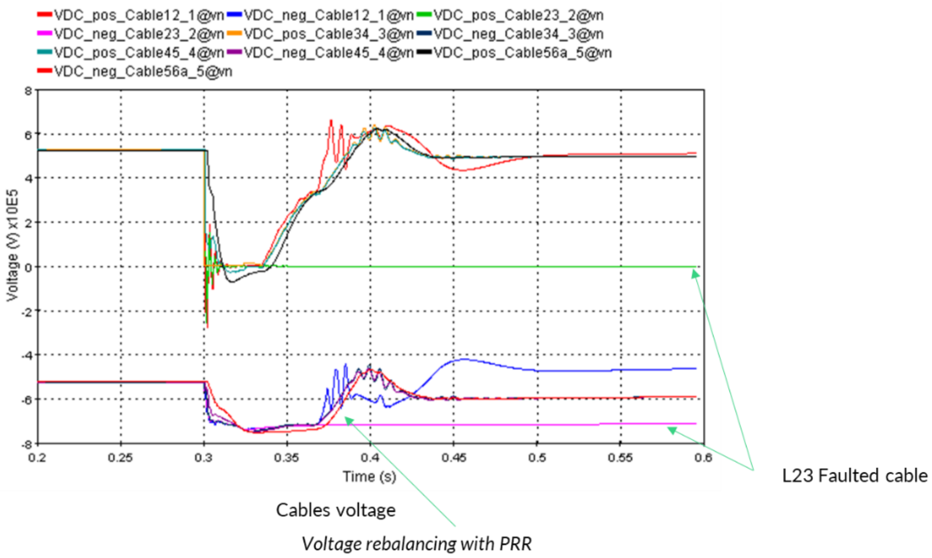


Figure 11-44: Pole to ground fault sequence for the grid after extension.

	Before extension: "GB" + "NL"	After extension: "GB" + "NL" + "DK1"
Energy dissipated by surge arresters (min – max)	1 - 1.2 MJ	0.2 - 0.6 MJ

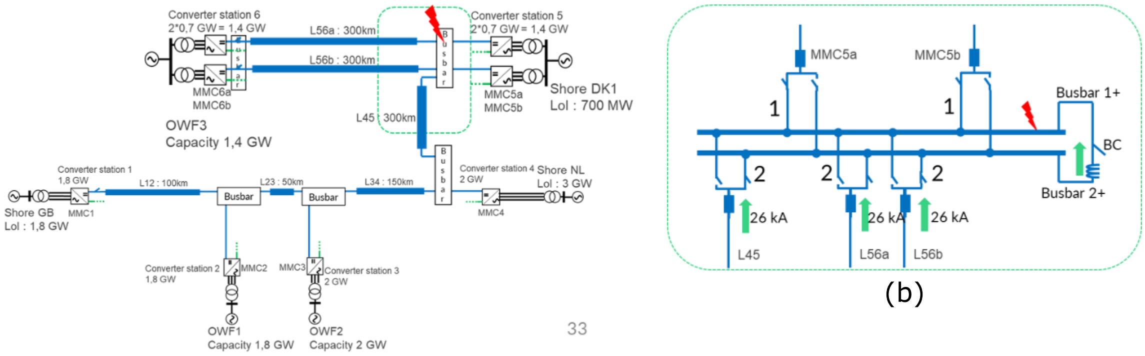
Table 11-13: Calculated energy absorbed by surge arresters

General findings:

- When two networks are connected together (extension), the surge arresters must be identical in both subnetwork in order to be able to share the energy to be dissipated.
- The energy to be dissipated rises with the number of cables and their lengths.
- The extension of the grid has few impact on the design of the existing SA if each subnetwork has their own SA.
- The dissipation of the energy is non homogeneous within all surge arrester but depend on the fault location.
- The pole rebalancing sequence reduces the energy dissipated by the surge arresters because it discharges the healthy pole faster.
- The design of SA (considering overvoltages after pole to ground fault) should take into account the worst case when pole rebalancing device is not activated or fails. In this case the pole rebalancing is effectuated by opening the AC breakers and by grounding both poles for example by means of a shunt resistance.

11.5.3. Case 2b

In this case the simulations are also performed on symmetric monopolar configuration and pole to ground fault. The aim is to check the impact of a busbar fault on the design of the DCCBs for what concern the short time current. The sequence for busbar fault in the NS strategy is explained in section 11.4.3.4. The busbar fault is located close to station 5 on busbar 1+, see Figure 11-45. The short time current through the bus coupler BC in shown in Figure 11-46 when considering a DCR in series of BC equal to 0 mH. The short time peak current reaches a very high value of around 75 kA and remains higher than 40 kA for around 3 ms. This short time current is due to the discharge of the cable stray capacitances of the three adjacent lines. The first peak current contribution of each line can be calculated based on the pre-charged voltage (525 kV) and cable characteristic impedance (~25Ω) and is equal to around 25 kA. The duration of the short time current is directly related to the energy stored within the cables and therefore the length of the lines.



(a)

Figure 11-45: fault location for Case 2b

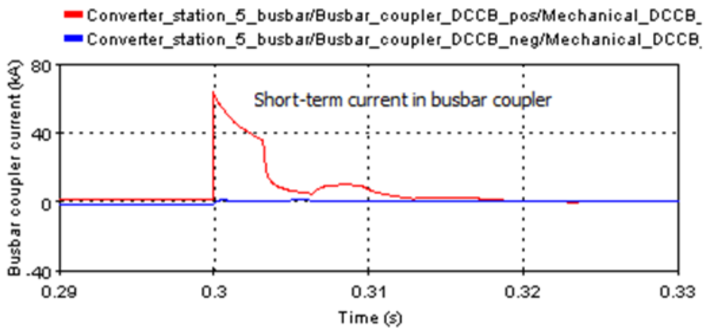


Figure 11-46: Short time current through the bus coupler for positive pole (red) and negative pole (blue)

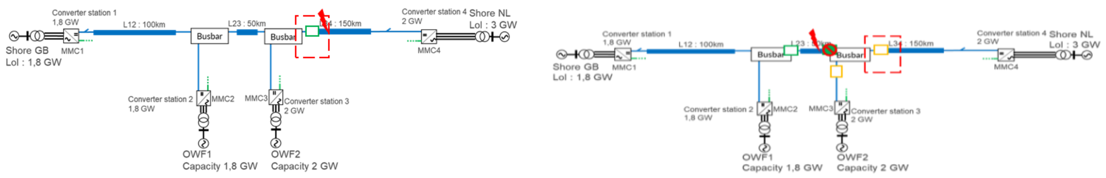
General findings:

- For NS strategy that has no need of DCR at the line ends, very high short time peak currents could appears during busbar faults or line fault close to the busbar. Such high current can reach several tens of kAs in few tens of microseconds and could damage the electric components. To avoid such high currents a DCR reactors could be installed in some particular location, for example is series to the bus coupler or on the line end.

11.5.4. Case 3

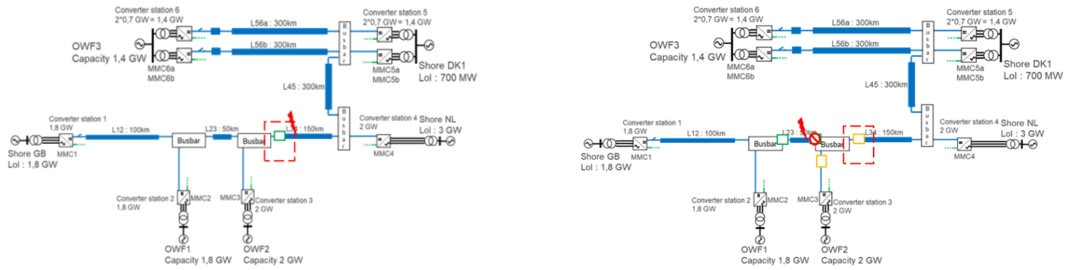
Simulations are performed for bipolar configuration and pole to ground fault. The aim of this simulation is to check the impact of the grid extension on the rating of the breakers (current breaking capability and energy requirements). The DCCB under consideration is the DCCB 34 connecting station 3 with line L34. It is important to determine the worst fault case scenario for the requirement of this breaker before and after the grid extension. Two conditions have been considered:

- Primary sequence, fault on line L34 close to station 3 ,see Figure 11-47 (a) and Figure 11-48 (a)
- Backup sequence during failure of the adjacent breaker DCCB 23, Figure 11-47 (b) and Figure 11-48 (b)



(a) (b)

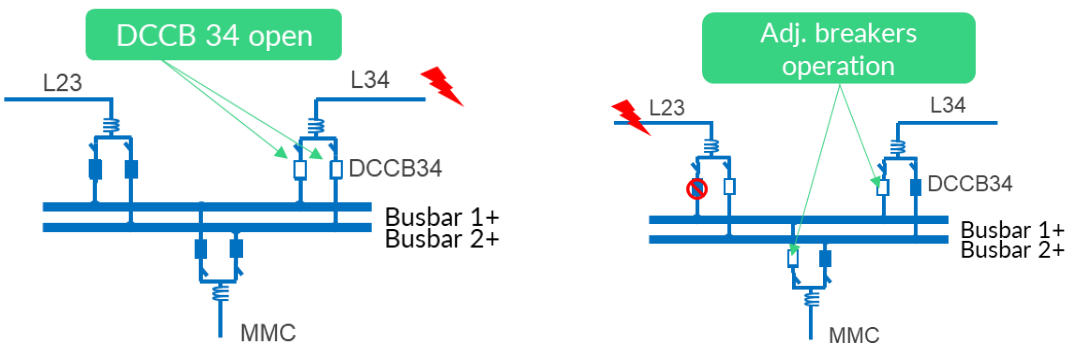
Figure 11-47: Before grid extension, primary sequence (a) and backup sequence (b)



(a) (b)

Figure 11-48: After grid extension, primary sequence (a) and backup sequence (b)

Figure 11-49 (a) shows that during the primary sequence for a line fault on L34 both the DCCB34 are opened and therefore the short circuit current is shared between the two breakers. Nevertheless, it has been considered the worst case when only one busbar is energized (e.g. during maintenance of a busbar). Figure 11-49 (b) shows that during a fault on line L23 and a breaker failure of DCCB 23, the breaker DCCB34 is required to open. Due to the delay of the breaker failure detection and breaker opening time, the current to be cleared during the backup sequence could be higher than that of the primary sequence. Simulations have therefore been carried out in order to determine the worst case condition. The results of calculated peak current and estimated energy requirement for the DCCB 34 are depicted in Table 11-4 for primary and backup sequence and for the grid before and after extension. Figure 11-50 shows the perspective fault current measured at DCCB34 during backup sequence before and after the grid extension for two values of DCR (50 mH and 140 mH); the prefault current has been subtracted in order to allow better comparison.

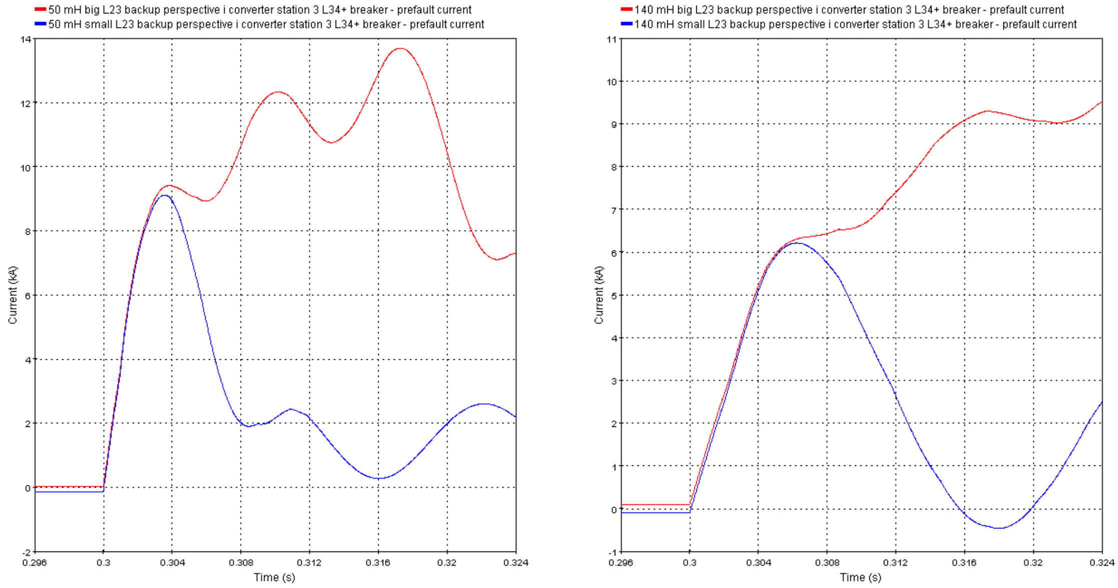


(a) (b)

Figure 11-49: Opening of the breaker DCCB34 during primary sequence (a) and backup sequence (b)

Network	Before extension: "GB" + "NL"		After extension: "GB" + "NL" + "DK1"	
DC reactor value	140 mH	50 mH	140 mH	50 mH
Primary sequence	9,5 kA ; 10 MJ	13 kA ; 8,5 MJ	9 kA ; 9,4 MJ	13 kA ; 8,3 MJ
Backup sequence	7 kA ; 2,4 MJ	10 kA ; 0,5 MJ	7 kA ; 3,1 MJ	10,4 kA ; 11,5 MJ

Table 11-14: Calculated peak current and estimated energy requirement for DCCB 34



(a) (b)

Figure 11-50: Perspective fault current (w/o prefault current) measured at DCCB34 during backup sequence before extension (blue) and after the extension (red) for DCR = 50 mH (a) and DCR = 140 mH (b)

<u>General findings:</u>

From the analysis of the obtained results of this particular case some observations can be made:

- The breaker requirements considering the primary sequence are not always more restrictive compared the backup sequence. Backup could be more restrictive in case of several MMCs and lines connected to the same node or if the backup breaker takes longer time to act. Moreover, lower is the value of the DCR and more important could be requirements considering the backup sequence.
- In this example the grid extension has few impact on the design of the breaker, see Figure 11-50. This is due to the fact that the peak current will not change during the first ms in which the backup sequence act (7ms). Indeed, the connection to station 5 is done through 150 km + 300km cables therefore, after

fault inception, the contribution to the fault coming from of station 5 will start after around 4ms (considering travelling waves speed of around 200 km/ms). Moreover it can be seen that due to the reflections the current starts to oscillate and the rate of rise of current is consequently no more constant after 4 ms.

- It should be noted that the grid extension has no impact on the design of the DCCB 34 during primary sequence because the fault current contribution comes only from stations 1, 2 and 3 even after extension.
- The grid extension could have higher impact on the design of the breaker if the extended grid is realized through short cables. Nevertheless an optimized choice of DC limiting reactor could help to increase the electric distance between the two interconnected grids.

11.5.5. Case 4

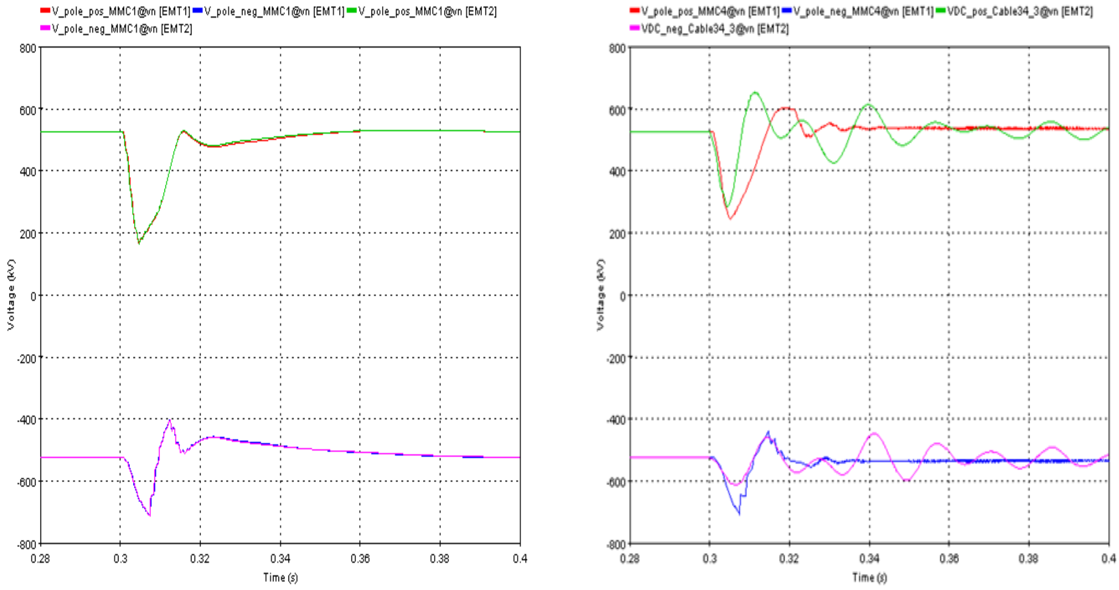
The simulations are performed for symmetric monopolar configuration and pole to ground fault. The fault location is on line L23, positive pole, close to station 23. The aim here is to analyse the impact of the extension on the design of the surge arresters and on the design of rebalancing devices.

The FS strategy for pole to ground fault in a symmetric monopole is explained in detail in section 11.4.2.4. The employed pole rebalancing reactors, installed as shown in section 11.3.6.3, are those on station 1 and station 4. Lines are protected with SA as shown in Figure 11-42. SA are designed in order to limit the overvoltage of healthy pole at around 1.4 pu. The voltage current characteristic of the SA is presented in section 11.3.5.

After pole to ground fault the line breakers (with DCR of 140 mH) of faulty line L23 open after around 2-3 ms and the grid is therefore separated in two different sub-networks. The first one is composed of station 1 and station 2 connected through L12 and the second sub-network is composed of station 3, 4, (5 and 6 for the extended grid) connected through lines L34 (L45, L56a, L56b). Because of the fast opening of the breakers, the MMCs are not blocked and the power is not interrupted within the two sub-networks.

DBS of station 1 is activated to rebalance the pole voltages of line L12 while the DBS of station 4 is activated to rebalance the pole voltages of lines L34 (L45, L56a, L56b in case of extended grid). Figure 11-51 (a) shows the pole voltages measured at station 1 for the grid before extension (red and blue) and after extension (green and purple). The grid extension will not impact the pole voltage rebalancing of the sub-network that includes line L12. Figure 11-51 (b) shows the pole voltages measured at station 4. It can be observed that, for the same fault clearing time, the voltage drop of the faulty pole on the sub-network is reduced in case of extended grid. This is the consequence of the increased cable stray capacitance and inductance that changes the dynamics of the discharge and could entail voltage oscillations.

Figure 11-54 shows the pole voltages measured at station 6 for the grid after extension. The voltage drop far away from the fault is less important because of the presence of stray inductances and DC limiting inductors that smooth the rate of change of voltage.



(a) (b)

Figure 11-51: pole voltages measured at station 1 (a) and station 4 (b) for the grid before extension (red and blue) and after extension (green and purple).

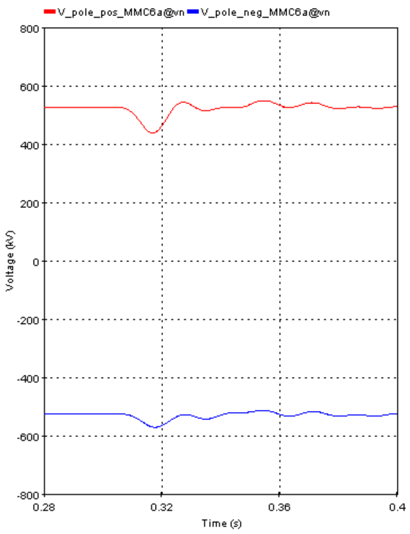


Figure 11-52: pole voltages measured at station 6 for the grid after extension (red and blue)

<u>General findings:</u>

- In order to ensure the voltage stability during the rebalancing sequence, appropriate DBS controls should be chosen and adapted to the length of lines.
- For the line located far away from the fault, the voltage unbalance can be very small, especially when the using DCR with high value of inductance.
- The energy absorbed by the DBS can vary with the length of lines to be charged and the duration of fault clearing time. In particular during a backup sequence the voltage could even drop to zero, therefore requiring higher value of energy.

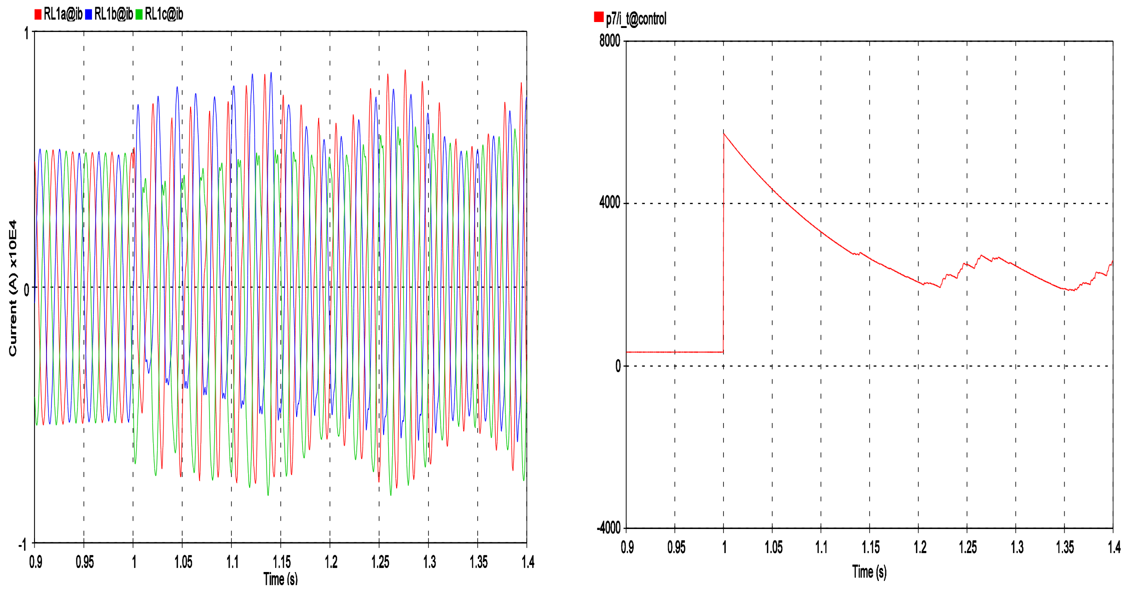
11.5.6. Case 5

In this case, the simulations are performed for bipolar configuration and pole to ground fault. The aim of this simulation is to shows the impact of the OWF modelling on the short circuit current contribution during a fault.

Figure 11-53 shows the perspective AC currents and the DC current after a DC fault happening at the MMC converter side of the OWF when using aggregated Fully Fed generator model. The fault happens at 1s. After the fault, the DC current starts to rise due to the discharge of the MMC sub modules (SM) capacitors. Once the DC current rises over 2 pu the MMC blocks, the SM capacitors stop to discharge and the energy stored within the arm inductance is released into the fault. During this time the Fully Fed converter of the wind turbine starts to limit the reactive output control at a value of around 1.2 pu. Some AC current oscillations (5-10Hz) occur after fault which are due to the interactions between the fully fed generators. More specifics control would be able to eliminate those oscillations.

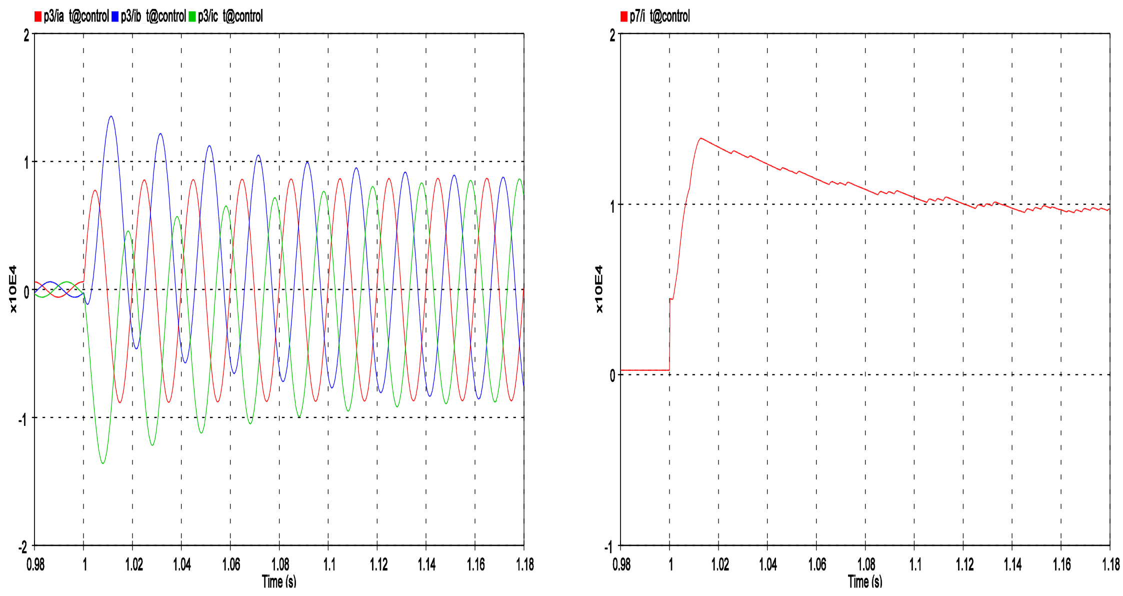
Figure 11-54 shows the perspective AC currents and the DC current after a DC fault happening at the MMC converter side of the OWF when using a simple OWF model (ideal AC voltage source in series with a short circuit impedance). After MMC blocking the DC current keeps to increase due to the contribution coming from the AC side. It can be seen that AC currents can reach up to 8-10 pu depending on the AC short circuit impedance.

Figure 11-55 shows the comparison between the OWF simple model (blue) and the aggregated Fully Fed generator model (red).



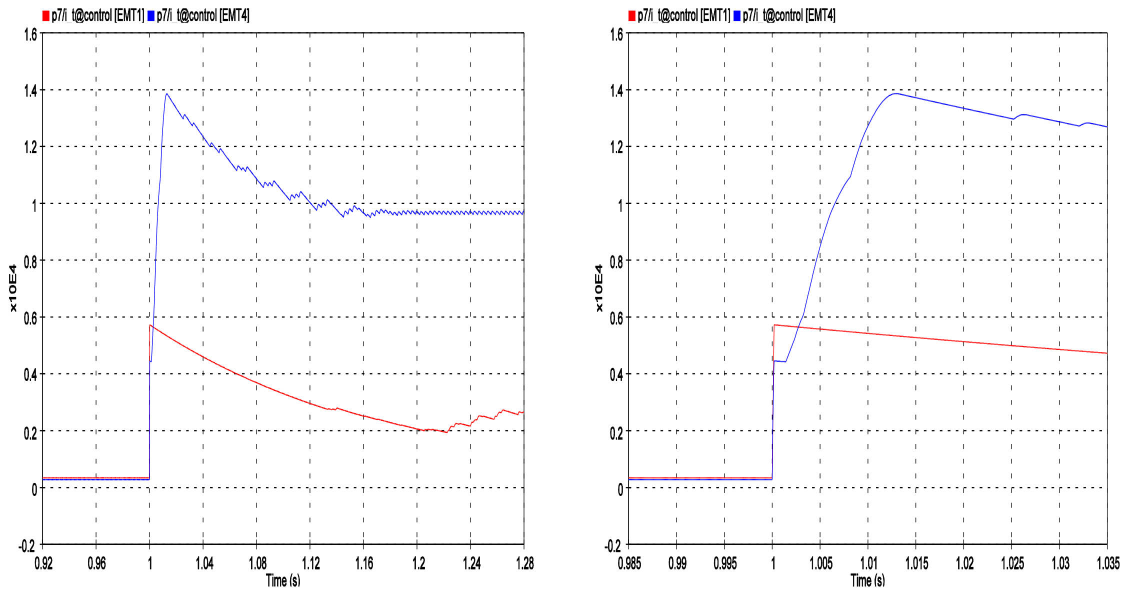
(a) (b)

Figure 11-53: AC currents (a) and DC current (b) after a DC fault using aggregated Fully Fed generator model



(a) (b)

Figure 11-54: AC currents (a) and DC current (b) after a DC fault using aggregated simple OWF model



(a) (b)

Figure 11-55: DC current comparison using the simple model (blue) and the aggregated Fully Fed generator model (red)

<u>General findings:</u>

- When using the detailed OWF model, it can be seen that after fault the AC currents are limited to around 1.2 pu, while the DC current reaches around 4-5 pu ad then decreases to around 1.2 pu.
- Using the simple models, after fault the AC currents and DC currents reach 8-10 pu.

- During the first 2-3 ms after fault the DC currents at the DC output of the converter are quite similar. This means that for the FS strategy able to clear the fault within 2-3 ms the type of employed OFW models is not of primary importance. Nevertheless if the DC fault clearing time is higher than 5 ms (e.g. for NS strategy or for backup sequence of FS strategy) the OFW modelling has more impact.

11.5.7. Case 6

The simulations are performed for symmetric monopolar configuration and pole to pole fault. The fault is located at the DC side of converter of station 4. The aim here is to analyse the impact of a breaker failure (positive pole) on the energy requirements for the SA of the healthy breaker (negative pole). It should be noted that during pole to pole fault, both breakers of the poles need to be opened in order to start the fault clearing process. Indeed, the breaker of each pole is designed for a TIV of around 1.5 pu where 1 pu is the pole to ground voltage (525 kV). Therefore only with a total TIV of 3pu is possible to interrupt the fault current if the total DC source voltage is at 2 pu. Positive and negative DC voltages are shown in Figure 11-56, 2.5 ms after the fault inception (at 0.3 s) the healthy breaker opens and the TIV appears. The voltage across the breakers is limited to around 1.5 pu, which has the effect to limit but not to clear the fault current, see Figure 11-57.

As shown in Figure 11-58 a certain current keeps flowing through the SA which entails an important energy absorption, see Figure 11-59. This energy absorption can be interrupted only by opening of the adjacent breakers. If the fault location is immediately after the busbar, the adjacent breakers can open within a delay of around 7ms (considering hybrid breakers) after fault inception. The energy absorption would therefore be around 20 MJ, which is much more than the energy calculated for the design of the breaker during the sequence for pole to ground fault in bipolar configuration as shown in Case 3.

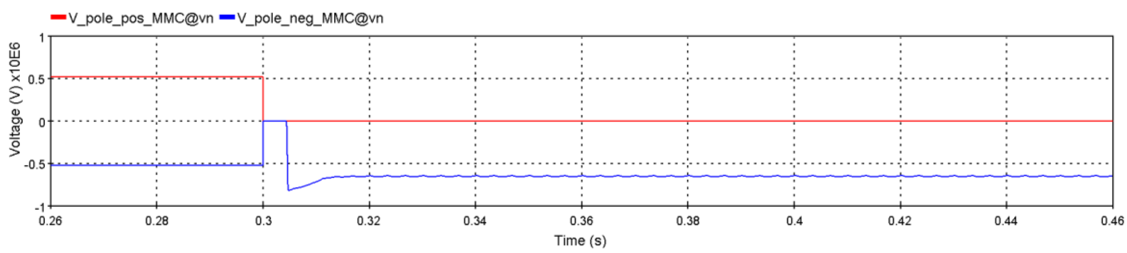


Figure 11-56: positive and negative poles DC voltages

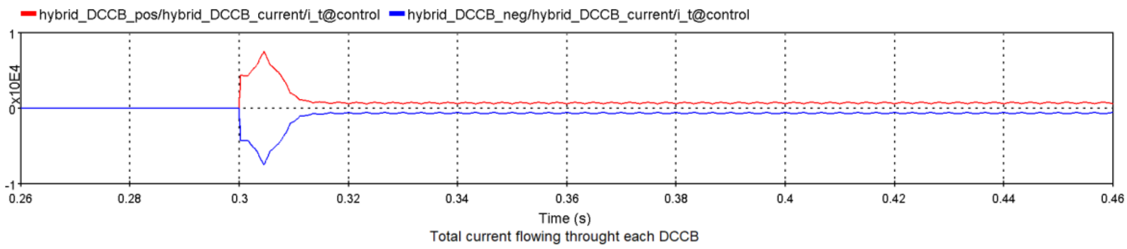


Figure 11-57: positive and negative poles DC currents

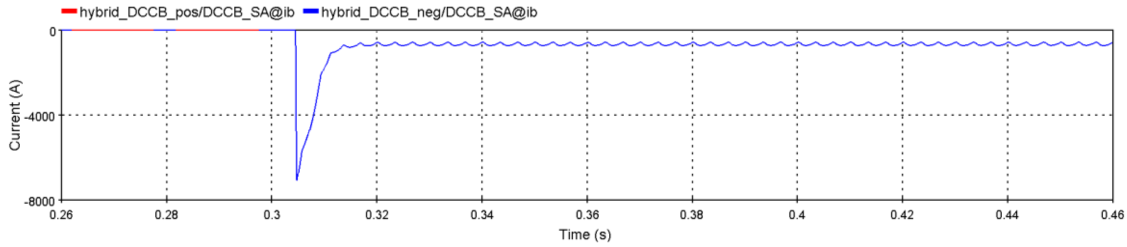


Figure 11-58: current though the SA of the DCCBs

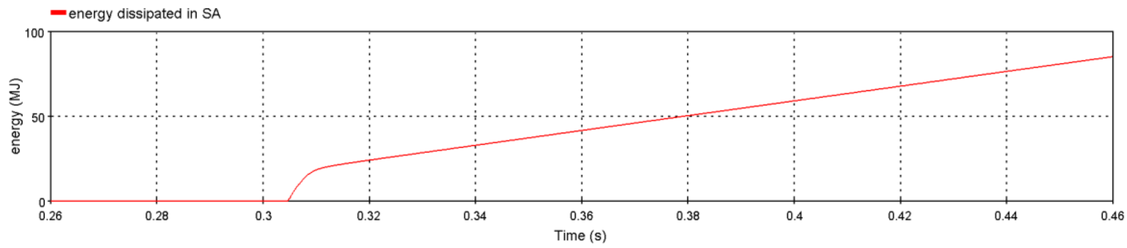


Figure 11-59: SA energy of the healthy DCCB

<u>General findings:</u>

- A breaker failure during a pole to pole fault in a symmetric monopolar configuration entails an important energy absorption on the SA of the healthy breaker. This scenario could be of major importance for the design of the energy absorption of the breaker.

11.6. Conclusion

11.6.1. Main takeaways

11.6.1.1. Common

- The design of the network (considering topology, architecture, voltage and power ratings) should take into account that a fault (e.g. DC line fault or internal converter fault) should not entails the power loss of more than the maximum allowed loss of infeed for each AC zone.
- Extension of an HVDC grid could be realised without need of DC/DC converters when the two systems have same voltage and configuration (e.g. symmetric monopole or bipole).
- Extension of an HVDC grid should take into account the insulation coordination constraints. For example, when connecting two symmetric monopolar systems, the surge arresters should have the same voltage-current characteristic in order to avoid unbalances of energy to be dissipated that could damage the SA.
- In a bipole with MR configuration designed to work without one pole (e.g. during one pole maintenance) the pole to pole or pole to MR faults should be avoided by means of pole segregation. If for geographical reasons or environmental constraints the poles and MR are in the same sheath, common mode of failure should be considered.
- Busbar fault cannot be excluded (risk analysis required): single busbar should be avoided if busbar fault can lead to the power loss of more than the maximum allowed loss of infeed.
- A breaker failure during a pole to pole fault in a symmetric monopolar configuration entails an important energy absorption on the SA of the healthy breaker. This scenario could be of major importance for the design of the energy absorption of the breaker.

11.6.1.2. Full selective fault clearing strategy

- The breaker requirements considering the primary sequence are not always more restrictive compared the backup sequence. Backup could be more restrictive in case of several MMCs and lines connected to the same node or if the backup breaker takes very long time to act (e.g. 10 ms) or if the line DCR has low value.
- The grid extension could have impact on the design of the existing breakers if the extended grid is realized through short cables or if there are high number of new converters close to the existing breaker. Nevertheless an optimized choice of DC limiting reactor could help to increase the electric distance between the two interconnected grids in order to have less impact.
- Protection strategies based on full selective fault clearing strategy are supposed to cause low impact on the AC side power flow. Nevertheless uncontrolled power disturbances are also present in the healthy part of the grid, see Figure 11-60 (a). Dedicated MMC controls need to be designed considering different grid configurations and possible extension in order to ensure DC stability during the restoring sequence.

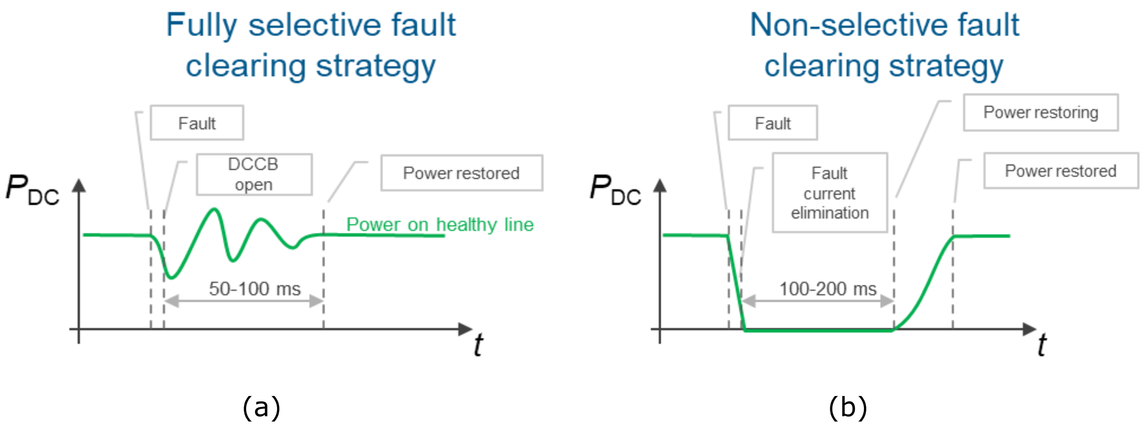


Figure 11-60: Power restoration for Full selective and non-selective fault clearing strategy

11.6.1.3. Non selective fault clearing strategy using converter breaker

- The converter breaker never see a current higher than the contribution coming from its related converter, independently from the protection sequence (primary or backup) and the extension of the grid. Therefore, extending the network doesn't change significantly the ratings for the converter breakers.
- Line breaker needs to be design with a short time let through current that depends on the extension of the grid. If the short time current becomes too high (e.g. higher than constraints imposed by electric components), a limiting inductor could be necessary in order to reduce this value.
- The extension of the grid seems to have low impact on the energy requirement of the breakers.
- For NS strategy that has no need of DCR at the line ends, very high short time peak currents could appear during busbar faults or line fault close to the busbar. Such high current can reach several tens of kAs in few tens of microseconds and could damage the electric components. To avoid such high currents a DCR reactors could be installed in some particular location, for example is series to the bus coupler or at line ends.
- Protection strategies based on non-selective fault clearing strategy cause a controlled temporary stop of the power flow of the entire grid, see Figure 11-60 (b). MMC controls need to be coordinated considering different grid configurations and possible extension to ensure a reliable start-up of the power.

11.6.1.4. Voltage rebalancing and insulation coordination during pole to ground fault in symmetric monopole

- Due to the footprint and installation considerations, it is better to install the pole rebalancing devices onshore.
- It has to be considered that after a fault the network can be divided in several sub-networks, therefore each sub-network should have at least one pole rebalancing device in order to be able to restore voltage and power within the sub-networks.
- When two networks are connected together (extension), the voltage-current characteristics of surge arresters must be similar in both subnetworks in order to have a balanced share of the energy to be dissipated after pole to ground fault.

- The energy to be dissipated rises with the number of cables and their lengths, nevertheless the extension of the grid has few impact on the design of the existing SA if each subnetwork has their own proper SA.
- The pole rebalancing sequence reduces the energy dissipated by the surge arresters because it discharges the healthy pole faster.
- The design of SA (considering overvoltages after pole to ground fault) should take into account the worst case when pole rebalancing device is not activated. In this case the pole rebalancing is effectuated by opening the AC breakers and by grounding both poles for example by means of a shunt resistance.
- Voltage rebalancing in non-selective fault clearing strategy using PRR takes around 100 ms. The design of the PRR (inductance and star point resistance) is strongly related to the stray capacitance and inductance of the DC system and thus the length of the cables. A suitable design of the PRR need to take into account different grid configurations or extensions.
- Voltage rebalancing in full-selective fault clearing strategy using DBS takes around 10 ms. In order to ensure the voltage stability during the rebalancing sequence, appropriate DBS controls should be designed and adapted to the length of lines. For the line located far away from the fault, the voltage unbalance can be very small, especially when using DCR with high value of inductance. The energy absorbed by the DBS can vary with the length of lines to be charged; therefore during the design process the energy capability of DBS needs to take into account different grid configurations or extensions.

11.6.2. Technical challenges encountered during the simulations

This section presents the technical challenges that have been encountered during the modelling of the different fault case scenarios.

11.6.2.1. Equivalence between monopolar and bipolar faults

As already mention in section 11.3.9, in order to ease the integration of the models in the EMTP virtual mock-up only the symmetric monopolar mock-up has been realized. It can be said that it exists an equivalence between a pole to ground fault in a bipolar system and pole to pole faults on a symmetric monopolar (PROMOTioN Workpackage 4, 2017) (PROMOTioN Workpackage 4, 2019). This equivalence is not valid when looking at the pole to ground voltages of the poles, but remains effective regarding the short circuit currents. Nevertheless, some technical aspects need to be taken into consideration during the simulations in order to avoid mistakes. Figure 11-55 shows an equivalence between faults on the two configurations for the FS strategy during primary sequence. For the symmetric monopolar configuration it is necessary to open both the pole breakers of the faulty line while for the bipolar configuration only the breaker of the faulty pole need to be opened. In this case the equivalence is effective because each breaker is designed with a TIV (Transient Interruption Voltage) of around 1.5 pu where 1pu is the pole to ground voltage of a pole.

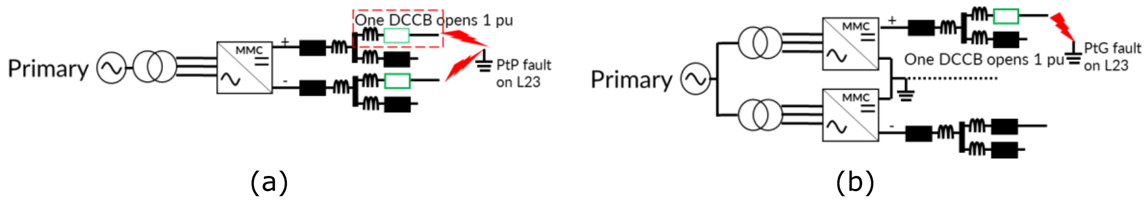


Figure 11-61: Equivalence between faults on the symmetric monopole (a) and bipole (b) FS strategy, primary sequence

Figure 11-62 shows the equivalence when considering the backup sequence for a line breaker failure. For the symmetric monopolar configuration it is necessary to consider that both pole breakers are in failure condition while for the bipolar configuration only one breaker can be considered in failure.

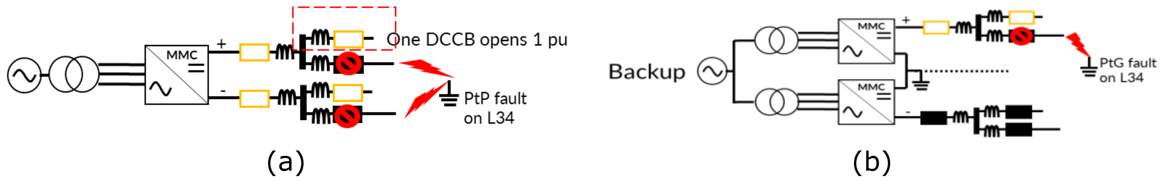


Figure 11-62: Equivalence between faults on the symmetric monopole (a) and bipole (b) FS strategy, backup sequence

11.6.2.2. Wind farm modelling

As shown in section 11.5.5 the modelling of the wind turbine generators can have an impact on the calculation of the short circuit current at the AC and DC side of the converters. The modelling of the wind turbine generators as proposed in section 11.3.8 has some technical challenges that are resumed hereunder:

- Modelling of WF using ideal AC voltage source in series with a short circuit impedance cannot take into account the current control limiting mode (around 1.2pu) of the fully fed converter of the wind turbine generators. This could have an impact on the AC and DC fault current calculation especially in case of a DC fault clearing time longer than few ms (e.g. for the NS strategy using converter breaker or FS strategy in case of backups). Using the simple model AC fault currents reach 8-10 pu and the DC currents also reach 8-10 pu.
- A model of an aggregated fully fed generator can be used in order to analyse the impact of the current control limiting mode. The AC current are efficiently limited to around 1.2 pu immediately after the faults, nevertheless the DC current at the converter output can reach higher value (over 2 pu) due to the discharge of the capacitor of the converter sub modules. Looking at the cable side the current can reach ever higher values due to the cable discharge phenomena. The current control limiting mode of the fully fed converter has an impact on the HVDC side only after few ms, depending on the energy stored within the arm inductances and cables. Such WT detailed model implies more complex and cost time EMT simulations; the necessity of this model should be confirmed with a more detailed analysis.
- Several aggregated fully fed generators have been used within the simulation case 5. Low frequency AC current oscillations occur on the WF side, this is due to the interactions between the fully fed generators. More specifics control would be able to eliminate those oscillations.

11.6.2.3. MMC control mode during fault

When modelling the WF using an aggregated fully fed generators it is necessary to take into account more detailed controls of the MMCs (e.g. V,F control, grid forming and grid following) before fault, during fault and after fault. Different control strategies exist and each strategy could have an impact on the fault current calculation as well on the power restoring.

11.6.2.4. Breaker design

Even if it was not the aim of this report, it appears that the design of breakers, limiting reactor and other protection components for one particular strategy should take into account different fault cases (line fault, busbar fault, etc.), sequences (primary and backups for several possible component failures), grid configurations and possible grid extension. An analytic approach for the calculation of voltage and current stresses within the components could help to have a more broad understanding of the possible constraints and to identify a more reliable and optimal design.

12. Appendix F – Companion Guide

12.1. Glossary

HVDC system	An electrical power system which transfers energy in the form of HVDC current between two or more AC buses and comprises at least two HVDC converter stations with DC transmission lines or cables between the HVDC converter stations.
Synchronous Areas	An area covered by synchronously interconnected TSOs, such as the synchronous areas of Continental Europe, Great Britain, Ireland-Northern Ireland and Nordic and the power systems of Lithuania, Latvia and Estonia, together referred to as 'Baltic' which are part of a wider Synchronous Area
Interlinked HVDC systems	Two or more HVDC systems connected via a dedicated network (e.g. offshore AC hub).
Onshore HVDC converter station	Part of an HVDC system which consists of one or more HVDC converter units installed in a single location together with buildings, reactors, filters, reactive power devices, control, monitoring, protective, measuring and auxiliary equipment. It is proposed to use the wording *onshore* HVDC converter station (to avoid confusion with remote-end converter station).
Remote-end HVDC converter	An HVDC converter station usually connected to an *offshore* platform or island.
DC connected Power Park Module (PPM)	A power park module that is connected via one or more HVDC interface points to one or more HVDC system.
DC connected demand	A load that is connected via one or more HVDC interface points to one or more HVDC system.
Hybrid Project	Hybrid projects are transnational, coordinated offshore energy generation projects. Typically, hybrid projects combine generation and transmission assets across maritime boundaries.
Grid Forming Converter	An inverter capable of supporting the operation of an AC power system under normal, disturbed and emergency conditions without having to rely on services from synchronous machines (Matevosyan, et al., 2019)

Grid Following Converter	A grid following converter behaves as a current source that follows the grid voltage angle and frequency. Thus it requires a sufficient system strength to operate correctly.
AC hub	An “AC hub” is an offshore AC network connected only via HVDC links to one or more onshore synchronous areas.
DC hub	The term “DC hub” is used per analogy to the “AC hub” and refers to the connection points in an offshore energy island. Technically, it can be seen as a specific case of a Multi-Terminal DC grid (MTDC Grid).
HVDC system integrator	A system integrator is the entity (e.g. TSOs) responsible of the integration of a new asset in an HVDC grid. Integration tasks may include advanced simulations, tuning of control systems, model acceptance testing, etc.
Primary DC grid control	The primary DC grid control refers to local DC node voltage control, as described in (CENELEC, 2020)
Secondary DC grid control	The secondary DC grid control refers to “Coordinated system control”, as described in (CENELEC, 2020)
PEIPS	Power Electronic Interfaced Power Source. This includes all assets interfaced via a converter to the AC grid. High Penetration of PEIPS is referred as HPoPEIPS
System strength	The ability of the power system to maintain and control the voltage waveform at any given location in the power system, both during steady state operation and following a disturbance (AEMO, 2020).

12.2. PURPOSE AND STRUCTURE OF THE DOCUMENT

This **Companion Guide** is a document that clarifies or extends the existing requirements of the Network Codes. This guide also complements and suggests additional requirements for hybrid projects. The requirements in this guide are **recommendations** that result from the analysis of the existing regulation and a stakeholder consultation process. **The Companion Guide is not a binding document.**

The goal of this project is to propose a voluntary set of technical guidelines for hybrid projects. This is done by:

1. Identifying the need for harmonization on the national implementation of the European Network Codes between the various Member States

2. Identifying potential technical barriers not covered by the existing network codes
3. Complementing/clarifying the relevant regulation and network codes, when it would be applied for hybrid projects

It is believed that this document will provide clarity for stakeholders and, hopefully, facilitate the development of hybrid projects. The guidelines provided could be followed by coordination between stakeholders or bilateral agreement, and not necessarily via grid code amendments. These guidelines should therefore be seen as basis for discussion between stakeholders, and not as potential articles of future network codes.

The document is structured as follows. Section 12.3 provides an overview of the key messages and lessons learned from the consultation process. Sections 12.4 and 12.5 gives more background on the project and on the methodology followed. The core of the Companion Guide lies in Chapter 12.6 to Chapter 12.8. Each of these chapters, provides technical guidelines at one of the three key interfaces (onshore AC side, DC side, and offshore AC side), as shown in Figure 12-1 and Figure 12-2

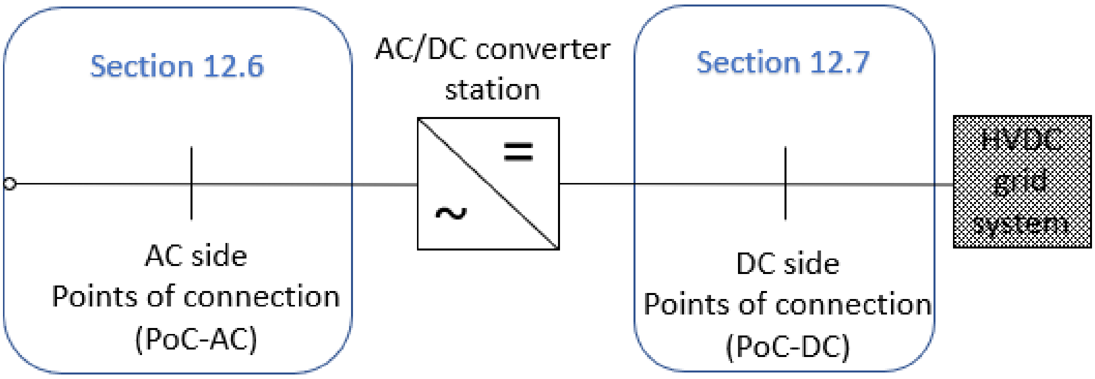


Figure 12-1: Definition of the Point of Connection-AC and the Point of Connection-DC at an AC/DC converter station (inspired from (CENELEC, 2020))

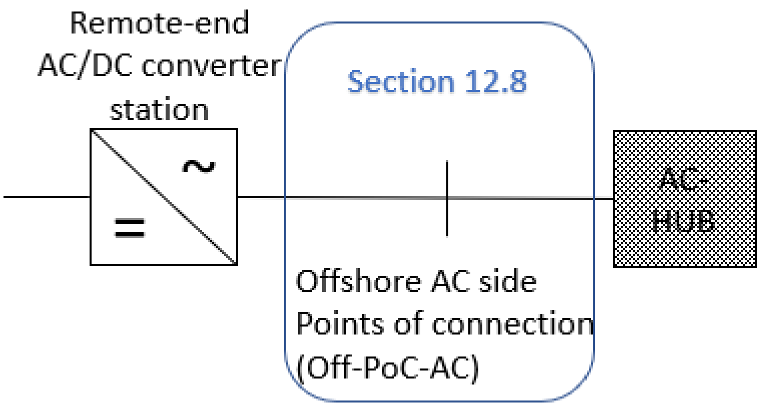


Figure 12-2: Definition of the Offshore Point of Connection-AC

12.3. Key messages and lessons learned from the consultation process

12.3.1. Key messages

Technical requirements for connection of future assets to offshore HVDC grids should be split depending on the point of connection of the asset. This provides clarity and is consistent with the European network codes and CENELEC standards.

Three key points of connection have been analysed:

1. Connection at the onshore AC grid
2. Connection at the DC grid
3. Connection at the offshore AC grid

The level of maturity and relevance of network codes differ significantly for each of these points of connection. Therefore, a dedicated methodology has been followed for analysing each of these three connection points.

- **Connection to onshore AC grid (PoC-AC)**

Regarding the connection at the **onshore AC grid**, it can be concluded that the existing European network codes cover most of the technical requirements and have been carefully written in order to be future-proof for more complex offshore topologies. However, variations in the national implementations of the European network codes might negatively impact the development of hybrid projects. **Articles potentially impacting hybrid projects have been identified and the impact of non-harmonization has been presented**. **Recommended actions for harmonization are also proposed.** It has to be noted that harmonization could be achieved via coordination between TSOs and other relevant operators and not necessarily via amendments of the network codes.

- **Connection to DC grid (PoC-DC)**

The analysis for **connection on the DC side** has been totally different as there are currently no network codes addressing these requirements. Defining requirements at the DC point of connection should cover any type of HVDC grid (e.g. MTDC, meshed or DC hub). **High-level guidelines have been provided based on the identified technical challenges of an HVDC grid**. It is **not recommended to include these guidelines in a network code for the time being** because of the current level of maturity of multi-terminal HVDC grids. Writing technical requirements in a legal document seems too early in the development of the technology could be counterproductive as it might influence negatively technological choices and creativity of manufacturers.

In a first stage of development of hybrid projects, it is expected that TSOs or a consortium of TSOs will draft more detailed technical and functional requirements for MTDC grids after analysis of the system security needs. This is likely to be done on a project to project basis. **It is recommended to draft these requirements via increased coordination between system operators and TSOs and increased consultations with manufacturers.** However, **in a second stage of development, the need of a network code for the DC side will very likely arise** in order to facilitate connection to and extension of HVDC grids.

- **Connection to offshore AC grid (OffPoC-AC)**

The last point of our analysis was the connection to offshore AC hub. This analysis has been performed via **a gap analysis between technical challenges of an AC hub and existing requirements in the European connection codes**. The inherent technical challenges of an AC hub are **somehow similar to a very high penetration of Power Electronic Interfaced Power Sources** (PEIPS). For that reason, **it is not recommended to apply strictly the requirements of the existing RfG and DCC.** A list of the European connection codes articles identified as having a gap for AC hub has been provided, as well as **the identified gaps and proposed guideline to close the gaps**. Finally, recommendations have also been proposed to **extend the requirements for remote-end HVDC converters connected to an AC hub.**

12.3.2. Lessons learned from the consultation process

General comments

The workshops and consultation process was generally well received by all stakeholders. It was mentioned that the comments received in the first round of consultation were integrated in the draft version of the document. Most of the stakeholders outlined the complexity of the work and agreed with the relevance to shed light on some technical issues that could slow down the development of hybrid projects.

Most of the feedback received focused on the DC point of connection chapter, meaning that this an important point of attention for the stakeholders. On that aspect, most of the comments were in favour of a collaborative approach to gain more practical experience before drafting an updated or dedicated grid code on the DC point of connection.

Some comments also pointed out the importance of defining clear roles and boundaries when developing HVDC grids. Going from point-to-point HVDC connections, where the DC side is the responsibility of the vendor, to multi-terminal HVDC grids, where the DC side is the responsibility of the TSO (or another non-TSO operator) constitutes a big shift in mentality. Therefore, some existing roles might have to be redefined or additional roles might need to be created. In addition, a clear definition of roles, responsibilities and ownership is required. This is a very important remark but is out of scope of this document, which focuses only on the technical aspects.

Points which required clarification of reformulation of our recommendations

This section lists the points that have been outlined by stakeholders during the consultation process.

- The use of real-time replica by a third party system integrator can de-**risk** interoperability issues. Some stakeholders outlined that this has been proven in recent projects. This final version of the document does not take position on the need for a system integrator but includes clearer recommendations towards the use of replicas.
- The use of 'black-box' model is accepted by TSOs who fully **understand** that intellectual property of vendors has to be respected. However, this should not be at the expense of model quality and lack of flexibility (i.e. possibility to tune parameters).
- The need for harmonization for multi-terminal DC grids and for "**interlinked** HVDC systems" are not exactly the same. For "interlinked HVDC systems", Section 12.6.7 does not apply.
- **Recommendations** on DC grid protection strategy now include the "protection zone matrix" concept described in (CENELEC, 2020), which takes into account the fault clearing strategy and impact on the onshore grid.

Considerations for a future grid code for the DC point of connection:

This section specifically addresses lessons learned for the potential creation of a grid code focusing on the DC point of connections.

- **It is so far unclear whether the scope of the current HVDC code should be extended or a separate regulation should be launched.**
- Significant work has already been performed by CLC/TC 8X Working Group 06. This document covers all technical HVDC topics that are specific for HVDC Grids and is now followed by the IEC TC 115/WG 15. This IEC work is very promising and it is expected that some parts could be integrated in a future grid code.
- The elaboration of more specific requirements for the DC point of connection will probably be a long process. Most of the remarks received are in favour of a collaborative approach between all stakeholders to draft these requirements. Also, a sufficient consultation period should be foreseen due to the complexity and importance of the topic.

12.4. Background

12.4.1. What is a Hybrid Project?

A hybrid project, as defined in (Berger, 2019), is a combined transmission and generation asset that serves the two following purposes:

- Cross-border interconnection
- Evacuation of offshore wind

In other words, hybrid projects refer to offshore transmission infrastructure combining transport of offshore wind energy and cross-border transfer. This is therefore not a "technical" definition. However, the fact that hybrid projects are cross-border could result in a higher need for harmonization between national implementations of the European network codes.

The most likely, hybrid projects in the North Seas will be **multi-terminal DC grids (MTDC grids),** as shown in Figure 12-3**,** or **radial point to point HVDC connections to an AC hub**, shown in Figure 12-4.

According to the definition of the European network code, an MTDC grid is composed of a single **HVDC system**. Although the radial HVDC connections to an AC hub are strongly dependent between them, it is unclear whether they can be defined as a single HVDC system. Therefore, the term **interlinked HVDC systems** is used for this latter configuration.

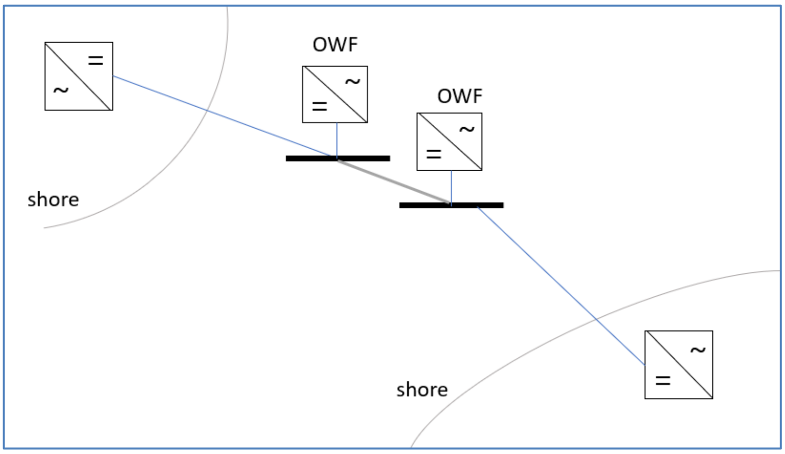


Figure 12-3: MTDC example

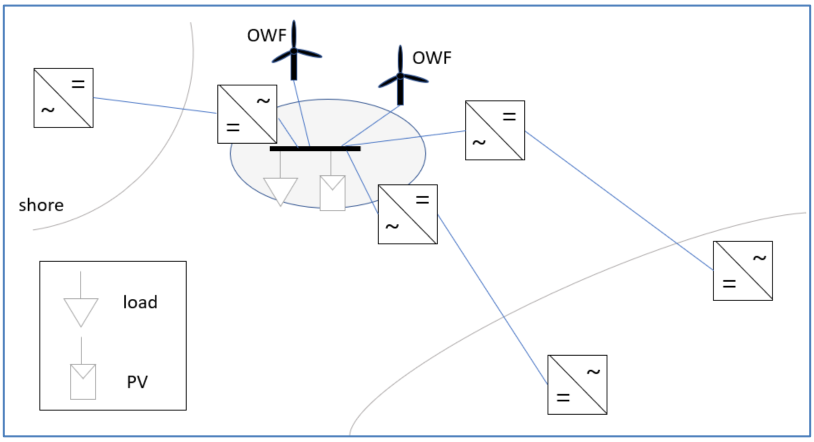


Figure 12-4: AC hub (or interlinked HVDC systems) example

12.4.2. Why is this document useful?

Existing Network Codes focus mainly on technical requirements at the interface to the onshore AC grid. Since hybrid projects will connect several Member States, it is likely that **the need for harmonization of these requirements will arise**. It is also important to identify requirements in the HVDC NC that have a significant impact on the design of hybrid projects.

This document provides also **technical guidelines at DC interfaces**. It has to be noted that this last set of guidelines is not mature enough for a direct implementation in a Network Code. However, it is believed that it would serve as a basis for discussion with the relevant stakeholders.

Another important aspect is to look at the technical requirements on the AC hub where it is expected that generation, load and storage will be connected in the future. The current RfG and DCC scope of application is defined as follows: "This Regulation shall not apply to: (a) power-generating modules connected to the transmission system and distribution systems, or to parts of the transmission system or distribution systems, of islands of Member States of which the systems are **not operated synchronously with either the Continental Europe, Great Britain, Nordic, Ireland and Northern Ireland or Baltic synchronous area".** This emphasizes that **clarity should be provided for offshore AC hubs.**

12.4.3. Why is this document needed now?

The development of **offshore wind is key for meeting carbon neutrality** in Europe by 2050. It is likely that more than 200GW of offshore wind will be installed in the North Sea and approximately 450GW3 in total in all European seas. It has been shown in many studies that multi-purpose projects (such as evacuation of wind and cross-border interconnectors) can bring **significant cost reductions to the offshore transmission infrastructure**. In addition to these cost savings, these hybrid projects are a mandatory first step towards the eventual construction of more complex meshed offshore grid structures.

[3] WindEurope, *https://windeurope.org/wp-content/uploads/files/about-wind/reports/WindEurope-Our-Energy-Our-Future.pdf*

12.5. Methodology and structure of the companion guide

The analysis is split by technical requirements or guidelines at three different points of connection in order to facilitate understanding. Each point of connection serves as boundary for requirements. It is worth mentioning that the maturity of network codes, technologies and/or practical experiences is not at the same level for all of these three points of connection. Therefore, the methodology used is adapted slightly depending on which point of connection is analysed. The points of connection are shown in Figure 12-1 and Figure 12-2.

The following sections describe more in detail the proposed methodology at each analysed point of connection.

12.5.1. Technical guidelines for point of connection:

12.5.1.1. At the onshore AC grid (PoC-AC)

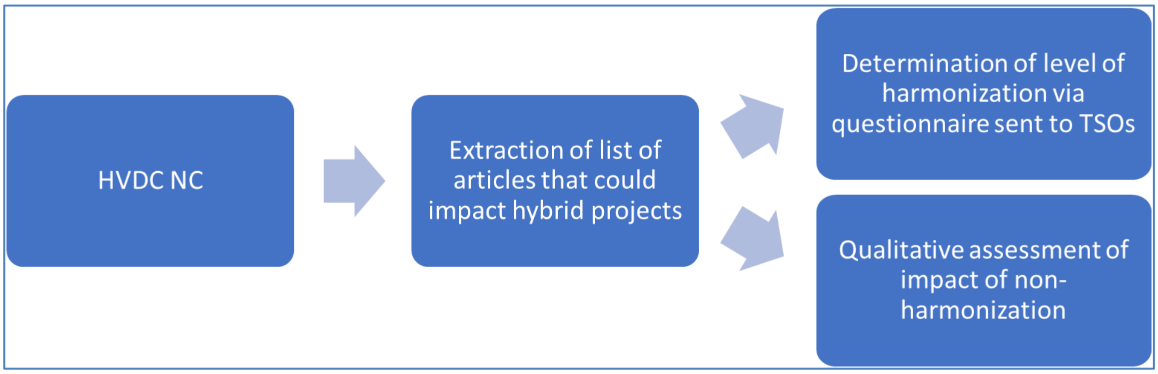


Figure 12-5: Methodology used for Onshore AC Point of Connection

Starting point:

- European Network Codes, in particular the HVDC NC, are designed specifically to take into consideration the impact of new assets on the onshore grid.

Tasks performed:

- Identification of articles having a potential impact for hybrid projects
- Analysis of national implementation of the European connection network codes
- Qualitative assessment of the impact of non-harmonization of these articles for hybrid projects

Main outcomes:

- List of selected articles with associated level of harmonization and impact of non-harmonization
- Proposition of high-level actions

12.5.1.2. At the DC grid (PoC-DC)

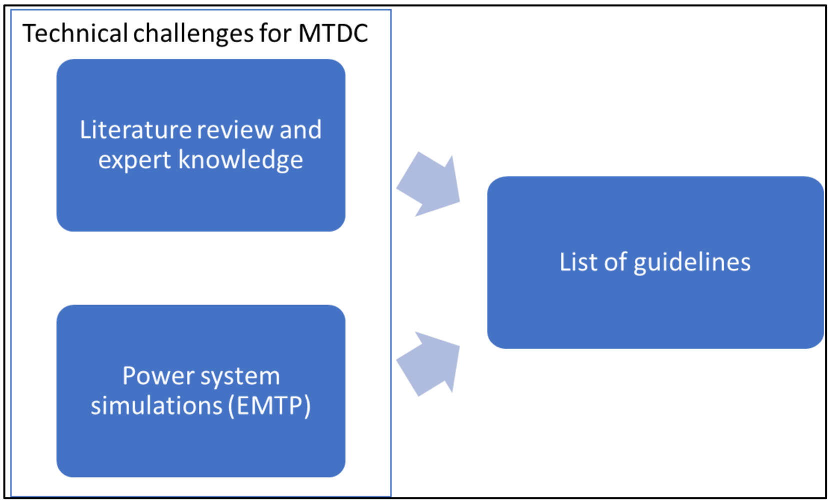


Figure 12-6: Methodology used for Offshore DC Point of Connection

Starting point:

- Connection network codes do not impose requirements at the PoC-DC. Therefore, this part of the work uses as main references the following documents:
  - CENELEC standards
  - CIGRE technical brochures on HVDC
  - European projects, such as:
  - PROMOTioN (in particular WP11)
  - BestPaths (in particular WP2)
  - MultiDC
- ENTSO-E papers on:
  - Standardized control interface for HVDC SIL/HIL conformity tests
  - Position on Offshore Development

Tasks performed:

- Identification of technical challenges of offshore hybrid projects via literature review and consultation with relevant stakeholders
- Power system simulations have been performed using EMTP software. These simulations have been performed mainly to evaluate impact on the DC side of different protection strategies, HVDC grid configurations and HVDC grid extensions. Simulations have been performed using a non-project specific grid with realistic parameters. It is believed that results are representative of the phenomena to consider but do not provide set of values

Main outcome:

- Technical Guidelines

12.5.1.3. At the offshore AC grid (Off-PoC-AC)

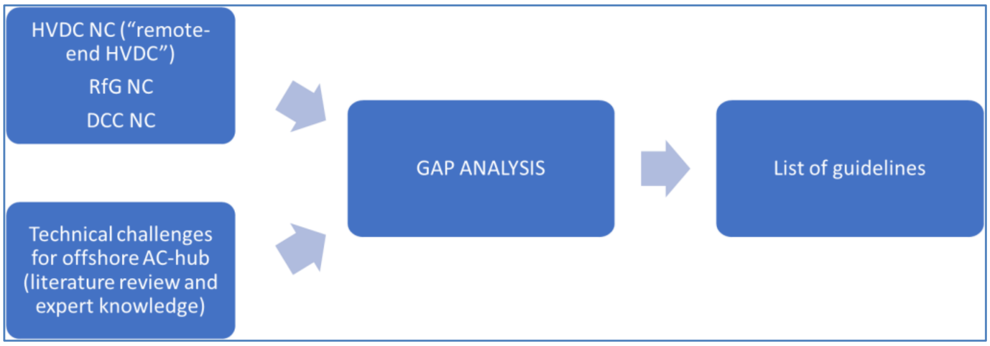


Figure 12-7: Methodology used for Offshore AC Point of Connection

Starting point:

- Connection network codes are not specifically designed for islanded systems. The existing requirements for the "remote-end HVDC converter" and "DC connected power park modules" cover to some extent the requirements for AC hubs. However, gaps still exist.
- Because the scope of application of the RfG and DCC NC does not cover AC hubs, additional documents have been used, including:
  - HVDC NC, RfG NC, DCC NC
  - CIGRE
  - European projects, such as:
    - MultiDC
- ENTSO-E paper on High Penetration of Power Electronic Interfaced Power Sources and the Potential Contribution of Grid Forming Converters (HPoPEIPS)
- National Grid Draft Grid Code on Grid Forming Converters

Tasks performed:

- Identification of the challenges of an AC offshore hub in comparison with a Synchronous Area
- Identification of technical requirements needed based on the AC hub inherent characteristics
- Gap analysis between the existing European connection network codes and the needs derived from the specific challenges for offshore AC hubs

Main outcomes:

- Identification of articles in existing network codes not directly applicable to AC hubs
- Technical guidelines

12.6. Connection to onshore AC grids

12.6.1. Introduction

This chapter focuses on the existing requirements for connection of HVDC systems on onshore AC systems. The main document of reference is the HVDC NC (European Commission, Network Code on HVDC Connections, 2016). This document was originally devised with traditional point-to-point HVDC systems in mind. The document only contains generic references to more complex HVDC topologies. For this reason, this study aims to identify parts of the HVDC NC that could have an impact on the development of hybrid projects. The study consisted of the following steps:

- Identification of HVDC NC articles important for hybrid projects;
- Analysis of the national implementations and their impact on hybrid projects;
- High-level assessment of the impact of non-harmonization and proposal of actions

The chapter follows the structure of the HVDC NC, where each of the requirements falls into one of the following categories:

- **Active power control and frequency support:** requirements related to control of active power and AC system frequency, i.e. frequency ranges, frequency sensitive modes, maximum loss of power infeed, etc.
- **Reactive power control and voltage support:** requirements concerning P-Q capability of the HVDC equipment, voltage control, voltage ranges and AC power quality.
- **Fault ride-through capability:** requirements on the behaviour of the HVDC equipment during and after AC and DC faults.
- **Other control schemes related to AC grid:** requirements on additional control schemes not directly related to AC voltage or frequency control. This includes oscillation damping, energization, synchronization, grid forming, etc.
- **Power system restoration:** requirements on black-start capability of the HVDC system.
- **Protection devices and settings:** requirements concerning the protection of the HVDC system, and any changes to the settings of the control schemes (e.g. priority ranking, parameter re-tuning).
- **Information exchange and coordination:** requirements on the exchange of information between HVDC system components and TSOs, such as simulation models, measurement signals, settings and fault recordings.

For specific articles of the HVDC NC, proposals for harmonization are made. In some cases, although harmonization would indeed be beneficial for the development of hybrid projects, it is believed that the impact of non-harmonization would be small enough to not constitute a blocking point. Instead, in such cases, it is recommended that appropriate coordination of the involved actors (TSOs, owners, etc.) should be enough to mitigate any issues that might arise. The colour code shown in Figure 12-8 has been used to illustrate our qualitative assessment on the impact of non-harmonization:

	Non-harmonization could: • Be a blocking point • Lead to significant cost to re-design equipment • Improbable that other solutions exist
	Harmonization not strictly required • Increased coordination between stakeholders required • Harmonized requirements on the DC side could be an option
	Non-harmonization not seen as a blocking point, but high coordination is recommended

Figure 12-8: Colour code used to illustrate the impact of non-harmonization

12.6.2. Active power control and frequency support

12.6.2.1. Overview

NC Article No.	Topic	Current Degree of Harmonization	Impact of Non-harmonization	Proposed Action
11.1	Disconnection Ranges	National implementations differ on over-frequency thresholds	Medium, might cause operational challenges.	Consider harmonization of requirements within same synchronous area towards the most stringent requirements.
13.3	Automatic remedial actions	Depends on local constraints. Defined on a project to project basis.	Low, can be mitigated by coordination in the design of the secondary DC Grid control	Maintain Coordination between TSOs. Increased coordination should result in integration of the remedial actions in the secondary DC Grid Control.
15 (Annex II.A)	Frequency Sensitive Modes	Some differences in parameters (such as droop, deadband)	Low, could be coordinated by secondary DC Grid control	Coordination between TSOs and definition of requirements at the PoC-DC.
17.1 and 17.2	Maximum Loss of power	National implementations vary, value not explicitly stated in all national implementations. Most TSOs link it to the Frequency Restoration Reserves (FRR). No mention is made on total maximum system loss.	Medium, will impact the hybrid project design.	Specify the maximum allowed total power loss in each synchronous area to the value of the frequency containment reserve (FCR) Investigate the harmonization of the maximum loss of power in each LFC of the same synchronous area and impact on FRR, considering the dynamics of HVDC grids.

Table 12-1: Onshore AC Grid – Harmonization Analysis for Active Power Control and Frequency Support

12.6.2.2. Article 11.1 – Frequency Ranges

- **Harmonization diagnosis:** The analysis mainly targets the harmonization within synchronous areas. Each synchronous area shares a common frequency and there is a framework between the different operational zones to share their frequency reserves. However, the national implementations of the HVDC NC exhibit some variations. For example, discrepancies have been observed between the minimum times that the HVDC converters (onshore) are requested to remain connected in case of over frequency. A summary of the frequency ranges is given in Table 12-2.

Frequency range	47 Hz – 47.5 Hz	47.5 Hz – 48.5 Hz	48.5 Hz – 49 Hz	49 Hz – 51 Hz	51 Hz – 51.5 Hz	51.5 Hz – 52 Hz
BE	60 s	Unlimited	Unlimited	Unlimited	Unlimited	30 min
DE	60 s	90 min	90 min	Unlimited	90 min	15 min
DK	60 s	90 min	90 min	Unlimited	90 min	60 min
FR	60 s	90 min	90 min	Unlimited	90 min	15 min
GB	60 s	90 min 30 s	90 min 30 s	Unlimited	20 min	15 min
IE	60 s	90 min	90 min	Unlimited	90 min	60 min
NL	60 s	90 min	90 min	Unlimited	90 min	15 min
NO	60 s	90 min	90 min	Unlimited	90 min	15 min
SE	60 s	100 min	100 min	Unlimited	100 min	30 min

Table 12-2: Frequency ranges of North Sea Member States

- **Impact of non-harmonization:** When onshore converters of a hybrid project are connected to the same synchronous area, it is possible that one of the onshore converters of the hybrid project trips due to over-frequency, whereas the rest of the hybrid project remains in operation (while both onshore converters see the same frequency). This tripping impacts the power transfer throughout the hybrid project, therefore the possibility of operational challenges caused by the HVDC system cannot be excluded. It is noted that this potential issue could be also relevant in the case of point-to-point HVDC assets connected to the same synchronous area.
- **Recommended Follow-up Action:** To address this problem, harmonization of the frequency ranges within each synchronous area should be considered towards the most stringent requirements. This could contribute in preventing operational challenges that may arise.

12.6.2.3. Article 13.3 – Automatic remedial actions

- **Harmonization diagnosis:** Remedial actions are specific to the needs of each system, and this is reflected in most of the national implementations, where site-specific requirements are usually determined. Some specific examples are blocking of frequency control or freezing of power ramping.
- **Impact of non-harmonization:** Harmonization of these requirements is not really desirable due to the different needs of each system. However, hybrid projects would definitely increase the need for coordination between relevant system operators. This conclusion is in line with our stakeholder consultation.
- **Recommended Follow-up Action:** In general, TSOs responded in the questionnaire that maintaining and even increasing the level of coordination between them is essential. Increased coordination should result in integration of the remedial actions in the secondary DC Grid Control. This will ensure that any remedial actions taken will not jeopardize the security of the DC and AC grids.

12.6.2.4. Article 15 (Annex II.A) – Frequency Sensitive Modes

- **Harmonization diagnosis:** National implementations of the network codes provide various setting ranges depending on each system needs. Examples of different settings of parameters are given in Table 12-3.

Parameter	DE	FR	NL
droop s1 (upward regulation)	≥ 0.1%	3-12%	≥ 0.1%
droop s2 (downward regulation)	≥ 0.1%	3-12%	≥ 0.1%
deadband	0-200 mHz	no deadband	0-500 mHz
Frequency response insensitivity	30 mHz	10 mHz	10 mHz

Table 12-3: Comparison of Frequency Sensitive Modes between countries (non-exhaustive list)

- **Impact of non-harmonization:** When the hybrid connection is connected to the same Synchronous Area, frequency support can be only provided by the offshore assets. When the hybrid connection is between different Synchronous Areas, frequency support can be provided by the offshore assets and other Synchronous Areas.
  In both cases, in order to satisfy the frequency support requirements onshore, it is necessary to redirect the power from specific sources (e.g. an OWF) to specific onshore converters. This requires that the HVDC grid control can act fast enough to adjust the power flow in the hybrid project. Non-harmonized requirements will increase the complexity of the secondary HVDC grid controls. However, the impact of non-harmonization is considered as low.
- **Recommended Follow-up Action**: Harmonization of the existing requirements might not be strictly needed, but the coordination between the TSOs to establish HVDC grid control requirements is considered essential. HVDC grid control requirements are further discussed in Section 12.7.

12.6.2.5. Article 17.1 and 17.2 – Maximum loss of power

- **Harmonization diagnosis:** The maximum loss of power infeed is typically calculated using dynamic simulations and might be limited by thermal, voltage or frequency constraints. According to the received responses to our questionnaire, the majority of the TSOs evaluate the frequency risk based on their largest power plant and acceptable loss of power exchanged with neighbouring Load Frequency Control (LFC) areas. Therefore, the requirements depend on the LFC and alignment is not observed even between TSOs belonging to the same synchronous area.
- **Impact of non-harmonization:** The harmonization concerns mainly the sizing incident (e.g. N-1, N-2) and impact on active power exchanges for a contingency in the HVDC grid system. Non-harmonization would impact the HVDC grid design in order to respect the maximum loss of power exchanges between each LFC.
- **Recommended Follow-up Action:** It is proposed to:
  - Specify the maximum allowed total power loss in each synchronous area to the value of the frequency containment reserve (FCR)

- Investigate the harmonization of the maximum loss of power in each LFC of the same synchronous area and impact on FRR sizing. It has to be noted that the time constants for restoration of the healthy parts of a hybrid project are (theoretically) much smaller than for the onshore grid. However, further research is required to evaluate the impact of a loss of infeed during a very short time (e.g. hundreds of ms) on the onshore grid stability and on the sizing of FRR in each LFC area (Article 157 of System Operation Guideline (European Commission, Establishing a guideline on electricity transmission system operation, 2017))

12.6.3. Reactive power and voltage support

Voltage stability and control is usually a local problem. Furthermore, as far as the Voltage Source Converter (VSC) technology is concerned, reactive power control does not depend on the topology of the HVDC system since it is independent from the active power. Therefore, we do not believe that harmonization is required on the articles of this category in order to extend HVDC systems to hybrid projects.

12.6.4. Fault ride-through capability

This category includes articles of the HVDC NC referring to the fault ride-through capability. The European NC defines requirements for a fault at the AC side of the onshore converter. Since such a fault could have a significant impact on the HVDC system, the following articles in this section have been deemed as important for a hybrid interconnection.

12.6.4.1. Overview

NC Article No.	Topic	Current Harmonization	Impact of Non-harmonization	Proposed Action
25.1	Fault ride-through capability	National variations in LVRT envelopes differ	Medium, could result in high costs to ensure compatibility of different HVDC systems	Maintain coordination between TSOs. Definition of harmonized requirements on the DC side
26	Post-fault active power recovery	Medium, differences in the restoration times and conditions	Medium, could result to non-compliance of at least one onshore converter	If harmonization is not possible, agreement and coordination between the TSOs is recommended
N/A	Over-voltage ride-through (OVRT)	Not existing requirement in ENTSO-e NC. Exists in some national implementations	Low, limited impact on hybrid assets	Article remains important for HDVC systems. TSOs agree it should be included in a future version of the HVDC NC

Table 12-4: Onshore AC Grid – Harmonization Analysis for Active Power Control and Frequency Support

12.6.4.2. Article 25.1 Fault ride-through capability

- **Harmonization diagnosis:** This article specifies the fault-ride through profile for which an onshore converter must remain connected to the AC system. The national implementations of this profile depend on the specific system needs, hence several differences can be observed between them. These differences can be observed in Figure 12-9 where the various national implementations of the fault ride-through profiles have been collected.

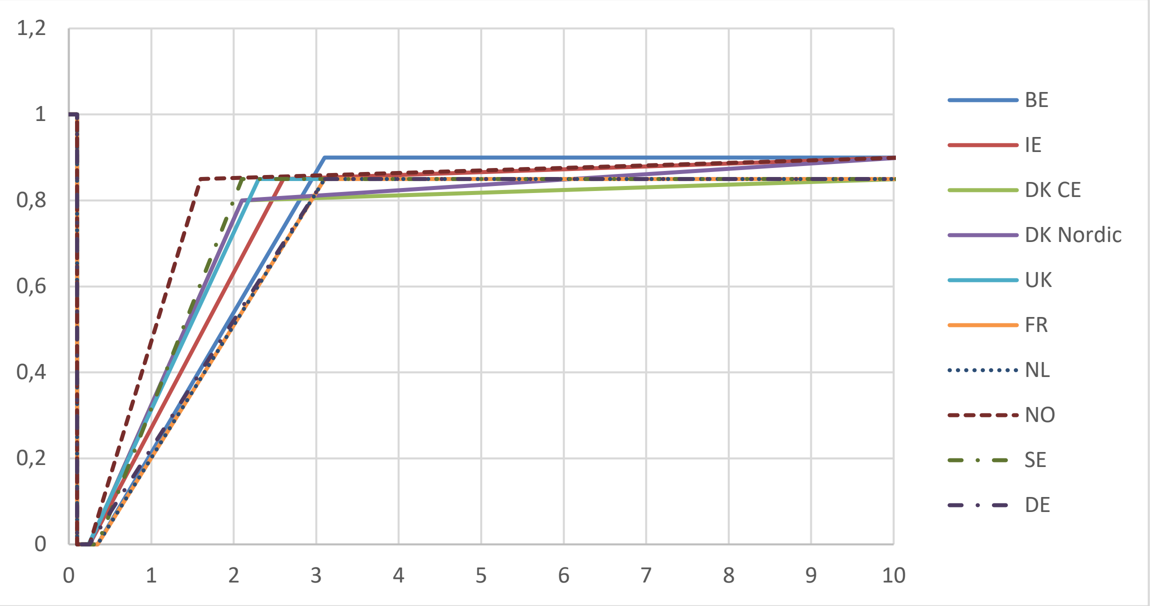


Figure 12-9: National implementations of FRT profiles

- **Impact of non-harmonization: An** AC fault has a significant impact on the HVDC side of the system. During such a fault, the onshore converter cannot evacuate the power injected into the DC grid by the OWFs. As a result, the hybrid project experiences an increase in the DC voltage level which has to remain between limits. Non-harmonization could lead to transient DC voltage profiles for which the original HVDC systems were not designed. This would potentially lead to the need for additional equipment (e.g. DC choppers) or control, and therefore additional cost.
- **Recommended Follow-up Action:** Due to different system needs, harmonization of the fault ride-through profiles is neither necessary nor desired. It is recommended to specify transient DC voltage profiles to which the equipment should be able to cope with following an AC fault at any of the HVDC converters. This would facilitate the extension of a DC grid even if this was not originally planned.

12.6.4.3. Article 26 – Post-fault active power recovery

- **Harmonization diagnosis:** Recovery of the power flow in the HVDC system following an AC fault could affect the stability of the combined AC/DC system. The desirable power recovery profile is usually determined from dynamic system stability studies. Discrepancies can be observed between the various national implementations. This is illustrated using the requirement for the French grid code, shown in Figure 12-10. In this example, the power should recover fully 200 ms after the fault is cleared and assuming that the post-fault voltage allows it.

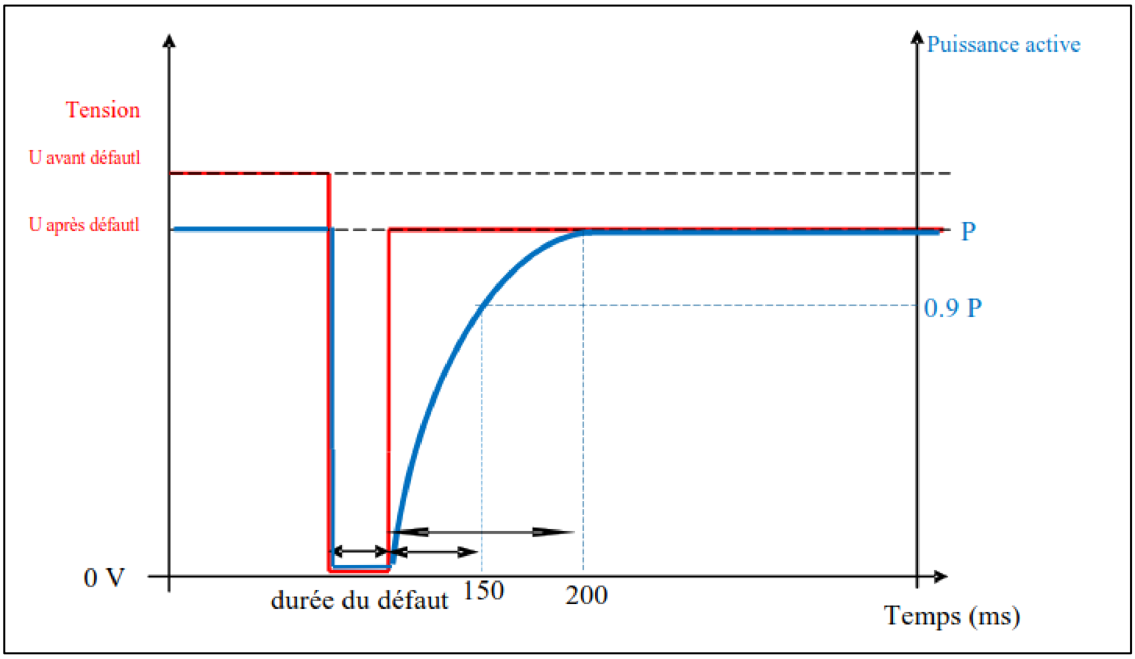


Figure 12-10: French National Implementation on Article 26 – post-fault power recovery. (RTE, 2018)

However, in the national variations the starting time for measuring this delay varies. Examples include:

- The starting time is the fault clearing.
- The starting time is when the voltage recovers to 90%.
- The starting time is when the voltage recovers to a value where pre-fault power can be re-established.

- **Impact of non-harmonization:** An AC fault temporarily interrupts (or significantly changes) the power transfer through an HVDC system (regardless of topology). For example, an AC fault at an onshore converter of a hybrid project could interrupt also the power flow (and, subsequently, the active power recovery) through another onshore converter. Definition of a slower recovery time at one side could lead to non-compliance at the other side.
- **Recommended Follow-up Action:** Harmonization on this aspect is considered important to resolve issues such as the aforementioned ones. In case this is not possible, coordination between the TSOs and/or bilateral agreements are required to reach a consensus on the characteristics of post-fault active power recovery on both sides and to design the HVDC Grid controls adequately.

12.6.4.4. Over-Voltage Ride-Through (OVRT)

- **Harmonization diagnosis:** Over-Voltage Ride-Through (OVRT) is not included in the current version of the HVDC NC. HVDC converter stations should be able to ride through an increased voltage on their AC side for a specific period of time. This could result, for example, following the clearing of an AC fault. This aspect is not part of HVDC NC.
- **Impact of non-harmonization:** In case OVRT becomes part of an HVDC NC in the future, non-harmonization is not expected to be as critical as fault ride-through since it does not necessarily lead to interruption of power.
- **Recommended Follow-up Action:** This is a gap in the current version of the HVDC NC and should be considered in a future version. This is also a point of agreement between the TSOs based on the answers received in the questionnaire.

An example of an OVRT profile has been proposed by CENELEC in (CENELEC, 2020) and is also shown in Figure 12-11.

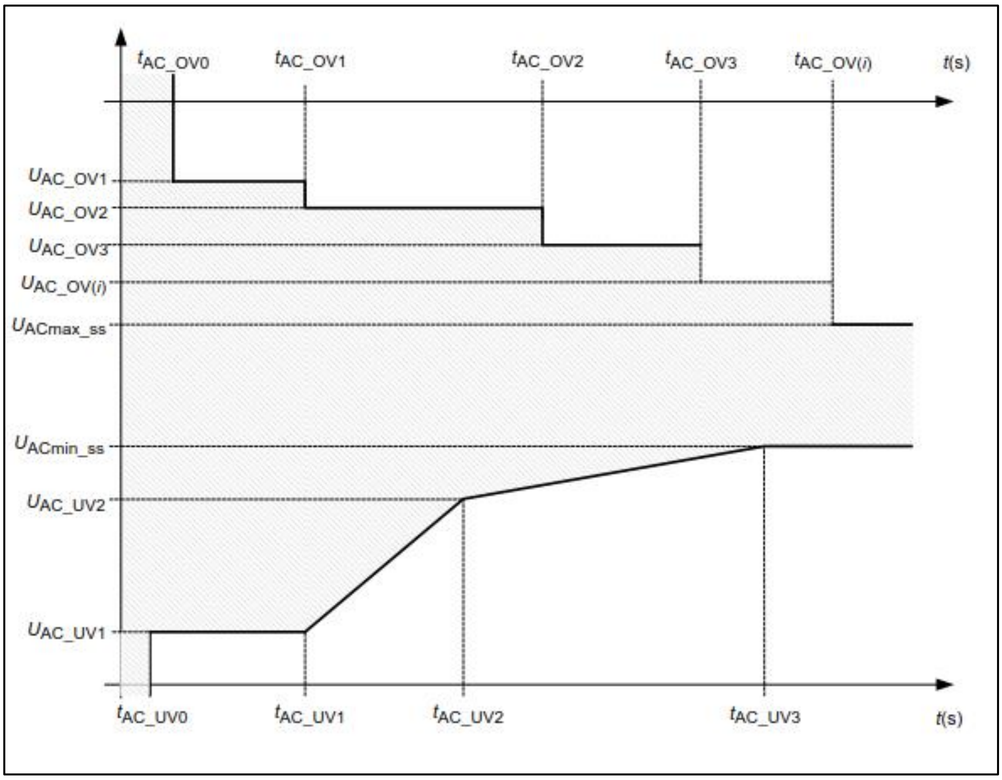


Figure 12-11: Example of AC voltage envelops (OVRT and FRT) from (CENELEC, 2020)

12.6.5. Other control schemes related to the AC grid

12.6.5.1. Overview

This section covers Articles on control schemes related to the AC grid that could have an impact on hybrid projects. A summary is given in the table below.

NC Article No.	Topic	Current Harmonization	Impact of Non-harmonization	Proposed Action
29.7	Interactions between HVDC systems or other plants and equipment	Project-specific, only some TSOs explicitly stated they consider DC transients	Medium, transients of the DC side affect the equipment. Additional equipment might be required	Listing of minimum harmonized requirements
30	Power oscillation damping capability	Project-specific, depends on location of the onshore converters and system needs	Low, minimum impact on the DC side, which can be resolved with coordination	Maintain coordination between the TSOs
33.1	HVDC system robustness (stability)	Each TSO considers events based on system experience and practice	Low, as long as a reasonably similar set of events on the DC side is considered by the TSOs.	Coordination of the events on the DC side would prevent any possible issues that might arise.
33.2	HVDC system robustness (transients at PoC-AC)	Project-specific for AC side requirements No requirements for DC side	Low, this is a gap for requirements on the DC side	Define harmonized requirements on the DC side (to be covered in PoC-DC requirements)

Table 12-5: Onshore AC Grid – Harmonization Analysis for Other control schemes related to the AC grid

12.6.5.2. Article 29.7 – Interactions between HVDC systems or other plants and equipment

- **Harmonization diagnosis:** Most TSOs treat this requirement on a case-by-case basis. This is partly due to limited experience with interactions between HVDC converters, but also due to the specific grid conditions on the points where HVDC converters are connected. To the authors' understanding, the focus of the article is mainly on the AC side. However, the transient behaviour of the DC side of HVDC systems is already being given special attention by some of the TSOs who replied to the questionnaire.
- **Impact of non-harmonization:** Different transient performances, especially on the DC side, are expected to become even more important following the extension to hybrid topologies and, at a later stage, to even more complex MTDC grid topologies. The security of the equipment has to be ensured, and this could lead to a need for additional equipment, such as DC choppers or DC filters.

- **Recommended Follow-up Action:** A more specific listing of minimum requirements and their harmonization among the TSOs could prevent costly re-design of the equipment in order to connect an additional HVDC terminal to existing hybrid projects. This point has also been highlighted in the discussion on Article 25.1

12.6.5.3. Article 29.7 – Interactions between HVDC systems or other plants and equipment

- **Harmonization diagnosis:** Most TSOs treat this requirement on a case-by-case basis. This is partly due to limited experience with interactions between HVDC converters, but also due to the specific grid conditions on the points where HVDC converters are connected. To the authors' understanding, the focus of the article is mainly on the AC side. However, the transient behaviour of the DC side of HVDC systems is already being given special attention by some of the TSOs who replied to the questionnaire.
- **Impact of non-harmonization:** Different transient performances, especially on the DC side, are expected to become even more important following the extension to hybrid topologies and, at a later stage, to even more complex MTDC grid topologies. The security of the equipment has to be ensured, and this could lead to a need for additional equipment, such as DC choppers or DC filters.
- **Recommended Follow-up Action:** A more specific listing of minimum requirements and their harmonization among the TSOs could prevent costly re-design of the equipment in order to connect an additional HVDC terminal to existing hybrid projects. This point has also been highlighted in the discussion on Article 25.1

12.6.5.4. Article 30- Power oscillation damping capability

- **Harmonization diagnosis:** The capability of an HVDC converter to damp power oscillations depends on the location of the converter. For this reason, it is reasonable that this requirement is mainly considered as site-specific. However, several TSOs define a frequency range between 0.1-2 Hz, which an HVDC converter should be able to assist.
- **Impact of non-harmonization:** This requirement is specific to AC systems and is not expected to have a significant impact on hybrid projects. However, it has to be highlighted that an HVDC system contributing to oscillation damping could introduce oscillations to another area. This should be coordinated between the TSOs connected to the same hybrid project.
- **Recommended follow-up actions:** Due to the site-specific nature of these phenomena, harmonization is not considered important. However, coordination between the various TSOs connected to the hybrid project is deemed essential in order to avoid adverse interactions and propagation of oscillations through the HVDC grid.

12.6.5.5. Article 33.1 – HVDC system robustness (stability after change in DC or AC grid)

- **Harmonization diagnosis:** Various events are defined by the TSOs, but there is not a standard or minimum set. For example, loss of communication is considered by most TSOs. In some cases, events such as load flow conditions are considered whereas some TSOs chose to leave this requirement as site-specific.
- **Impact of non-harmonization:** This requirement specifies that the HVDC grid should be robust to contingencies on the AC and DC grids. As long as a reasonably similar set of events on the DC side is considered by the TSOs, the impact of non-harmonization is expected to be minimal.

- **Recommended follow-up actions:** Harmonization of the events to be considered on the AC side is not essential, but coordination of the events on the DC side would prevent any possible issues that might arise.

12.6.5.6. Article 33.2- HVDC system robustness (Transients occurring on PoC-AC)

- **Harmonization diagnosis:** Mostly site-specific requirements are defined by the various TSOs. This is not unreasonable since the impact of a DC disturbance on the connection point depends largely on the grid conditions at that point.
- **Impact of non-harmonization:** This article currently focuses on the impact on the AC side and is specific to each system needs, hence harmonization is not required. However, it is important to specify similar requirements on the DC side, i.e. in the HVDC grid. It is important to note that all responding TSOs agreed that such requirements are important.
- **Recommended follow-up actions:** While harmonization on the AC side is not considered necessary, it is highlighted that DC side requirements are important to be specified. This will be investigated further in Chapter 12.7.

12.6.6. Power system restoration

If requested by the relevant TSOs or operators, a quote to enable black start capabilities should be provided. This is related to article 37 of the HVDC NC (European Commission, Network Code on HVDC Connections, 2016). In the case of hybrid connections, this black start capability could be provided by the DC PPMs or by another synchronous area.

The black-start capability is specific to the system restoration plan of each TSO, so harmonization of this requirement is not desired.

12.6.7. Protection devices and settings

12.6.7.1. Overview

NC Article No.	Topic	Current Harmonization	Impact of Non-harmonization	Proposed Action
34.1	Electrical protection schemes and settings	Project-specific Lack of operational experience makes short-term harmonization and even coordination challenging	High, lack of specific requirements can have significant impact on the design and cost of a hybrid project	More practical experience (e.g. via flagship project) is needed to define more specific requirements. Increased coordination between TSOs until maturity is reached.
36.1 and 36.3	Changes to protection and control schemes and settings	Project-specific Generic requirement	Low	Maintain coordination between the TSOs

Table 12-6: Onshore AC Grid - Harmonization Analysis for Protection devices and settings

12.6.7.2. Article 34.1 - Electrical protection schemes and settings

- **Harmonization diagnosis:** This article concerns the protection of the network taking into account the characteristics of the HVDC system. The protection relevant to the HVDC system is mentioned, but no further specifications are provided. Most national implementations define site-specific requirements.
- **Impact of non-harmonization:** Different protection strategies can be employed to protect HVDC grids, and each comes with different performance and cost. A more specific definition of the protection system characteristics (e.g. time from fault inception to fault clearing or time from fault clearing to power restoration) would facilitate the choice of the protection strategy. However, due to limited operation experience of complex HVDC systems, further investigation is required to come up with a set of requirements and/or HVDC protection philosophy. This further investigation should also shed light on the need for harmonization and the possible risks of non-harmonization. Nevertheless, the impact could be significant, especially in cases where the interconnection of grids with different protection philosophies is considered. Note that the case of interlinked HVDC systems is somewhat simpler in terms of protection, since there is no actual HVDC grid. Hence, the impact of non-harmonization between interlinked HVDC systems is not considered significant.
- **Recommended follow-up action:** It is important to gain more experience on the protection aspect of HVDC grids (e.g. via flagship project). DC breaker technology is still developing and significant advances have been achieved in the latest years. Protection philosophies, such as the non-selective approach making use of full-bridge DC fault-current blocking converters, are inherently different from the protection philosophy in AC grids, but should not be a priori dismissed. The protection requirements will be further discussed in the PoC-DC technical guidelines.

12.6.7.3. Articles 36.1 and 36.3 - Changes to protection and control schemes and settings

- **Harmonization diagnosis:** Most national implementations define project-specific requirements.
- **Impact of non-harmonization:** The extension from a point-to-point connection to a hybrid project, or connection to an HVDC grid, will most probably require the adjustment of the control settings. This article is sufficiently future-proof and does not distinguish between control of AC side or DC side magnitudes. As long as this is coordinated between the TSOs, non-harmonization is expected to have a minimal impact on the development of hybrid topologies.
- **Recommended follow-up action:** Maintain coordination between the relevant system operators and TSOs .

12.6.8. Information exchange and coordination

12.6.8.1. Overview

The articles shown in the following table have been considered as important for hybrid connections from this category:

NC Article No.	Topic	Current Harmonization	Impact of Non-harmonization	Proposed Action
51.1	Operation of HVDC systems	Project-specific	High, could lead to interoperability and compatibility problems	More practical experience is needed to define specific requirements in the regulation. Establishment of a standardized interface (an example is proposed in (ENTSO-E, 2020)), as well as increased coordination between TSOs and manufacturers are recommended.
54.1	Simulations models	Usually static, RMS, EMT and harmonic. Additional studies are asked depending on project	Medium, different level of quality would lead to lack of confidence in the simulations	Publication of a common modelling guideline for HVDC grid, agreed by TSOs.
54.4	Simulation models - Recordings	Project-specific	Low	Maintain coordination between the TSOs to share recordings, when needed

Table 12-7: : Onshore AC Grid - Harmonization Analysis for Information exchange and Coordination

12.6.8.2. Article 51.1 - Operation of HVDC systems

- **Harmonization diagnosis:** This article refers to the need for an automatic controller to coordinate the HVDC converter units in an HVDC system. Most national variations define project-specific requirements.
- **Impact of non-harmonization:** In order to facilitate interoperability and compatibility, it is important to have a standardized interface for this secondary DC grid controller. Currently, no standardized interface exists, but steps have already been taken in (ENTSO-E, 2020).
- **Recommended follow-up actions:** Further investigations to provide a standard interface are needed. Good examples are the ENTSO-E paper on standard control interface (ENTSO-E, 2020) or the recent CIGRE working group on "Interoperability in HVDC systems based on partially open-source software". Increased coordination between TSOs and manufacturers is also recommended.

12.6.8.3. Article 54.1 - Simulation Models

- **Harmonization diagnosis:** In most cases, static (load flow), RMS, EMT and harmonic models are the minimum required. Some TSOs ask for additional models, depending on the project, such as real-time replicas.
- **Impact of non-harmonization:** This article specifies the simulation models that the HVDC system owner should provide to the relevant TSO(s) (or system integrator). Availability of models with the adequate level of detail must be ensured for all parties involved in a hybrid connection. Lack of confidence on the simulation models and the relevant system studies could arise from different levels of quality.
- **Recommended follow-up actions:** Publication of a common modelling guideline for HVDC systems, agreed by TSOs, would provide clarity for stakeholders and ensure the same level of quality in the model of each asset of the HVDC grid. On a project-by-project basis, the use of real-time replicas should be considered already from the design process and throughout the lifecycle of the project (i.e. including during operation). The main benefit of real-time replicas is that they help to decrease the risk of the project by revealing possible interoperability issues (and enabling mitigating actions) before the actual commissioning of the project.

12.6.8.4. Article 54.4 - Simulation models – Recordings

- **Harmonization diagnosis:** Most national implementations define site-specific requirements.
- **Impact of non-harmonization:** Harmonization is not essential, but coordination is required between the TSOs in order to share all relevant recordings and compare models. This is even more important for hybrid connections where multiple HVDC converters possibly from different vendors shall exist.
- **Recommended follow-up action:** The sharing of recordings should be agreed between the TSOs when necessary and while respecting article 10 of the HVDC NC on confidentiality.

12.6.9. Summary table

NC Article No.	Topic	Current Degree of Harmonization	Impact of Non-harmonization	Proposed Action
11.1	Disconnection Ranges	National implementations differ on over-frequency thresholds	Medium, might cause operational challenges.	Consider harmonization of requirements within same synchronous area towards the most stringent requirements.
13.3	Automatic remedial actions	Depends on local constraints. Defined on a project to project basis.	Low, can be mitigated by coordination in the design of the secondary DC Grid control	Maintain Coordination between TSOs. Increased coordination should result in integration of the remedial actions in the secondary DC Grid Control.
15 (Annex II.A)	Frequency Sensitive Modes	Some differences in parameters (such as droop, deadband)	Low, could be coordinated by secondary DC Grid control	Coordination between TSOs and definition of requirements at the PoC-DC.
17.1 and 17.2	Maximum Loss of power	National implementations vary, value not explicitly stated in all national implementations. Most TSOs link it to the Frequency Restoration Reserves (FRR). No mention is made on total maximum system loss.	Medium, will impact the hybrid project design.	Specify the maximum allowed total power loss in each synchronous area to the value of the frequency containment reserve (FCR) Investigate the harmonization of the maximum loss of power in each LFC of the same synchronous area and impact on FRR, considering the dynamics of HVDC grids.
25.1	Fault ride-through capability	National variations in LVRT envelopes differ	Medium, could result in high costs to ensure compatibility of different HVDC systems	Maintain coordination between TSOs. Definition of harmonized requirements on the DC side
26	Post-fault active power recovery	Medium, differences in the restoration times and conditions	Medium, could result to non-compliance of at least one onshore converter	If harmonization is not possible, agreement and coordination between the TSOs is recommended
N/A	Over-voltage ride-through (OVRT)	Not existing requirement in ENTSO-e NC. Exists in some national implementations	Low, limited impact on hybrid assets	Article remains important for HDVC systems. TSOs agree it should be included in a future version of the HVDC NC
29.7	Interactions between HVDC systems or other plants and equipment	Project-specific, only some TSOs explicitly stated they consider DC transients	Medium, transients of the DC side affect the equipment. Additional equipment might be required	Listing of minimum harmonized requirements

NC Article No.	Topic	Current Degree of Harmonization	Impact of Non-harmonization	Proposed Action
30	Power oscillation damping capability	Project-specific, depends on location of the onshore converters and system needs	Low, minimum impact on the DC side, which can be resolved with coordination	Maintain coordination between the TSOs
33.1	HVDC system robustness (stability)	Each TSO considers events based on system experience and practice	Low, as long as a reasonably similar set of events on the DC side is considered by the TSOs.	Coordination of the events on the DC side would prevent any possible issues that might arise.
33.2	HVDC system robustness (transients at PoC-AC)	Project-specific for AC side requirements No requirements for DC side	Low, this is a gap for requirements on the DC side	Define harmonized requirements on the DC side (to be covered in PoC-DC requirements)
34.1	Electrical protection schemes and settings	Project-specific Lack of operational experience makes short-term harmonization and even coordination challenging	High, lack of specific requirements can have significant impact on the design and cost of a hybrid project	More practical experience (e.g. via flagship project) is needed to define more specific requirements. Increased coordination between TSOs until maturity is reached.
36.1 and 36.3	Changes to protection and control schemes and settings	Project-specific Generic requirement	Low	Maintain coordination between the TSOs
51.1	Operation of HVDC systems	Project-specific	High, could lead to interoperability and compatibility problems	More practical experience is needed to define specific requirements in the regulation. Establishment of a standardized interface (ENTSO-E, 2020) as well as increased coordination between TSOs and manufacturers are recommended.
54.1	Simulations models	Usually static, RMS, EMT and harmonic. Additional are asked depending on project	Medium, different level of quality would lead to lack of confidence in the simulations	Publication of a common modelling guideline for HVDC systems, agreed by TSOs. The use of real-time replicas should be considered since they can help in decreasing the risk of the project.
54.4	Simulation models - Recordings	Project-specific	Low	Maintain coordination between the TSOs to share recordings, when needed

Table 12-8: Summary of proposed actions

12.7. Connection to HVDC grid

Disclaimer: no connection code to HVDC grids has yet been defined. This companion guide proposes technical guidelines which can be seen as suggestions and starting points for future discussions.

The main focus of connection requirements to an HVDC grid is the DC grid security, which subsequently impacts the AC grid stability. Given the plans for offshore expansion in Europe, this impact will keep increasing in the future with more DC-connected PPMs and fewer synchronous machines.

In order to understand the need for HVDC grid requirements, this chapter starts by listing several technical challenges that HVDC grids face. This list does by no means intent to be exhaustive by addressing all possible issues. Instead, by pinpointing some of the most critical challenges, the aim is to justify the need for such requirements and for increased coordination at a European level.

Based on these challenges, high-level guidelines are proposed to facilitate the transition from point-to-point HVDC connections to more complex topologies, such as hybrid projects. Some of these guidelines may form the basis for new grid code connection requirements, while others refer more to design functionalities.

The proposed guidelines try to follow as close as possible the structure of the HVDC NC. Therefore, the guidelines will fall into one of the following categories:

- **DC power and voltage:** guidelines related to active power and DC voltage i.e. voltage ranges, maximum loss of power infeed, etc.
- **DC fault ride-through capability:** guidelines on the behaviour of the HVDC equipment during and after AC and DC faults.
- **HVDC grid control and stability:** guidelines on HVDC grid controls ensuring system stability.
- **DC grid restoration:** guidelines on restoration of the HVDC grid.
- **Protection devices and settings:** guidelines concerning the protection of the HVDC system, and any changes to the settings of the control schemes (e.g. priority ranking, parameter re-tuning).
- **Information exchange and coordination:** guidelines on the exchange of information between HVDC system components and relevant TSOs and operators, such as simulation models, measurement signals, settings and fault recordings. This could also include guidelines on model validation and acceptance testing.

12.7.1. Challenges for HVDC grids

In order to move from the current state of point-to-point HVDC links to HVDC grids, several challenges have still to be addressed. Some of these were already highlighted back in 2010 (Van Hertem & Ghandari, 2010), when the first concepts of European Supergrids based on HVDC technology were expressed. Although the respective technology has significantly advanced in the meantime, we are still not in the point of having “off-the-shelf” solutions or clear guidelines on how to construct HVDC grids.

The following sections highlight the most important challenges that have to be addressed in order to allow the development of hybrid HVDC grids.

12.7.1.1. Alignment of designs for topological compatibility

The “Topological compatibility”, as presented in (Plet, 2020), makes reference to the common design choices of separate HVDC projects that would facilitate their potential interconnection. This includes the aspects described in the following sections and emphasizes that coordinated planning is of key importance in the development of hybrid projects.

Due to the specificities and limited technological maturity of HVDC grids, it is recommended to have a strong coordination between system planning, grid connection and system operation. For example, any topological changes (not planned in the initial design) might need additional studies and adaptation. This is a large shift from the currently common “fit and forget” approach traditionally followed on the AC grid, where the original design is considered valid for the whole lifetime of the asset based on clearly defined requirements. However, with HVDC grids, a more dynamic and continuous approach is necessary to ensure the correct operation of the system, especially when adjustments or connection of new components (e.g. from a different vendor) are considered.

A strong coordination between the relevant TSOs, other operators and ENTSO-E in the grid expansion plans is highly recommended since it could foresee such problems and reduce the need for expensive corrective measures. It is however believed that there is already a strong level of coordination between these entities.

(a) DC voltage level

Although harmonization/enforcement of specific DC voltage levels should not be enforced in the regulations, alignment of DC voltage levels for projects in the North Sea should be still encouraged, especially when the possibility of linking HVDC systems is foreseen. Connecting hybrid project of different DC voltage levels might not be feasible or the cost of equipment to enable the connection (i.e. DC-DC converters) could be prohibitive.

(b) HVDC grid configuration

Figure 12-12 shows the existing possible HVDC point-to-point configurations. It should be noted that bipole configuration and asymmetric monopole could be realized using earth as current return, nevertheless due to European constraints earth return is not considered hereunder. Each configuration has its own characteristics, advantages and drawbacks depending on several factors (site installation, insulation coordination, reliability requirements, etc).

While most of the existing HVDC connections to offshore wind parks are symmetric monopole, it is unclear whether this configuration will remain the preferred choice in the future.

The choice of configuration for a point to point HVDC system comes from a Techno-economic Analysis. The best configuration might not be the same for a specific point-to-point project or if future expansion is foreseen. Techno-economic analysis for HVDC grids should include investment and operating costs, as well as consideration regarding technological readiness of protection components and extensibility studies. It is therefore recommended to include that aspect in the techno-economic analysis of future projects and coordinate with neighbouring projects, especially if the technoeconomic analysis does not show a clear cut between potential HVDC grid configurations.

Note that although it is theoretically technically possible to connect different configurations (e.g. bipole to symmetric monopole configuration), it induces additional complexity and costs.

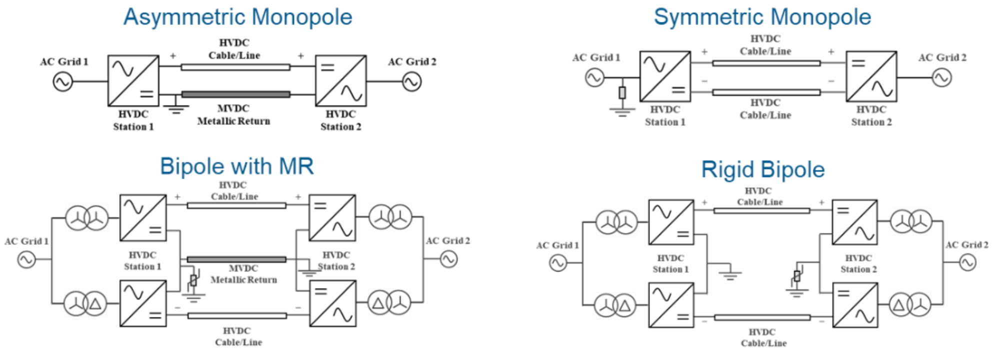


Figure 12-12: Possible HVDC point to point configurations

(c) DC Earthing

Similarly to the HVDC configuration, the choice of the DC earthing scheme is done at the design stage of the project. Earthing of symmetric monopole can be realized in several ways at the DC side (e.g. using shunt resistances or capacitors) or at the AC side of the converter. The most common grounding method is performed at the AC side using a star-point reactor as shown in Figure 12-13. Other AC side earthing systems are also shown in the figure.

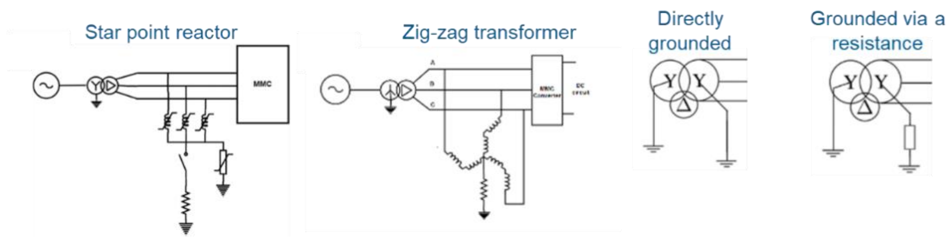


Figure 12-13: AC side grounding method for Symmetric Monopole

When extending a bipole to a DC grid only one station should be directly grounded in order to avoid circulating current through the earth. The other stations can be connected to the ground via an impedance.

Following the high number of grounding methods, it becomes clear that alignments on the DC earthing schemes could facilitate the connections of HVDC links to each other.

12.7.1.2. DC fault protection

The interruption of DC fault currents is a critical point that has to be resolved in order to allow more complex topologies. Compared to AC faults, DC fault current does not exhibit a natural transition from zero that allows to eliminate the electric arc when opening the breaker. Instead, complex mechanisms have to be developed in order to create an artificial zero-current crossing. Moreover the detection and the elimination of the faulty line have to be fast enough to sufficiently reduce the fault current before it can be cleared.

In the point-to-point HVDC case using VSC converters, fast HVDC protection is not required and can be realized through AC breakers. This implies a shutdown of the HVDC systems during at least a few seconds. This could pose an unacceptable risk for MTDC grids transferring high amounts of power (several GW) from offshore WFs to shore or between AC systems. Therefore, DC protection mechanisms will most likely be required for MTDC grids.

DC protection strategies can be divided into two stages, the fault clearing and DC grid fault recovery, see Figure 12-14. The fault clearing starts with the fault occurrence and finishes with the faulty component isolation. The fault recovery starts after faulty line isolation and has the aim to restore the power flow on the healthy part of the grid.

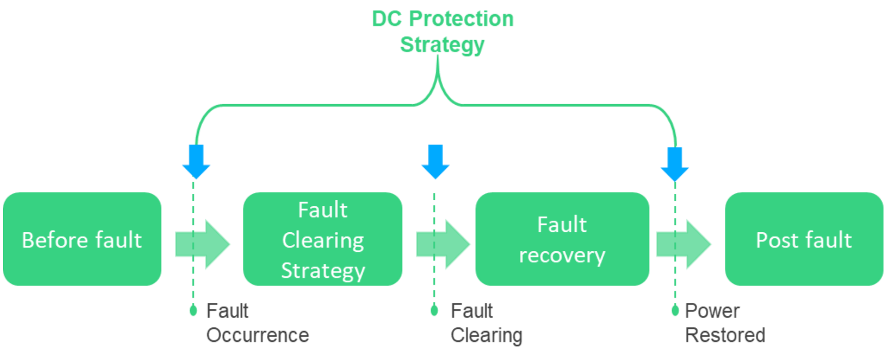


Figure 12-14: Stages of a protection strategy

CIGRE has proposed various fault clearing strategies that could be applied on HVDC grids in (CIGRE, 2018), to which the reader is referred for more details. Briefly, the protection strategies can be based on three main fault clearing philosophies:

- Full-selective fault clearing: This is directly inspired from protection of AC grids. Each DC branch is protected by one DC breaker at each end. Ultra-fast algorithms have to identify the faulty branch and the relevant DC breakers have to quickly eliminate the fault current.
- Non-selective fault clearing: Simply put, the whole DC grid is de-energized if a DC fault occurs. Before de-energization the faulted branch is identified and DC breakers disconnect it. Then the rest of the MTDC grid is gradually restored to normal operation.
- Partial selective fault clearing: The DC grid is split into several protection zones. If a DC fault occurs, the faulted zone is disconnected rapidly and the healthy zones resume operation.

It is worth to note that the DC protection strategy does not only impact the fault clearing itself but also the fault recovery as it can be seen in Figure 12-15.

- In a fully selective fault clearing strategy, after the faulty line isolation, an uncontrolled temporary power disturbance can appear for around 50-100 ms. This power disturbance is mainly due to the oscillation of energy among DC branch limiting reactors, branch stray capacitors and MMC converters. Moreover, depending on the fault location, one or more converters could be temporarily blocked, with consequences on the controllability of the system. It could be argued that the selective fault clearing leaves the system in a state that is somehow unknown in terms of energy balance. Therefore, dedicated MMC controls need to be designed in order to ensure DC stability and damp such oscillations during the power restoration sequence after fault.

- In a non-selective fault clearing strategy, after fault current elimination, the entire grid is shut down. This leads to a temporary power stop of the exchanged power through the entire DC grid. The state of the system is hence known after fault current elimination. The challenge of power recovery in a non-selective strategy is the coordination of the power ramp-up among the different MMC controls.

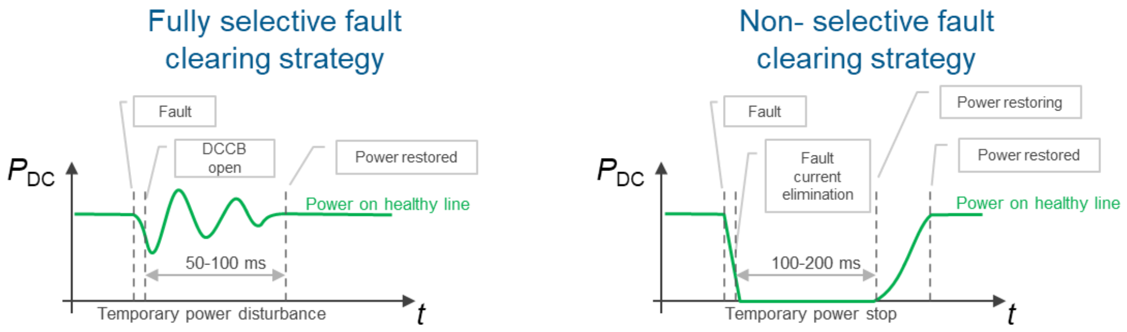


Figure 12-15: Fault recovery for protection strategies based on fully selective and non-selective fault clearing strategies

The choice of protection strategy needs to take into account several aspects like cost, reliability, extensibility features, technological readiness of the protection components and compatibility with AC system stability and constraints.

12.7.1.3. HVDC grid control and stability

The HVDC grid control should satisfy several objectives, among which:

- Ensure stability of the converters and the HVDC system, while respecting the maximum allowed loss of infeed of all connected AC networks
- Adverse interactions between converters either from the AC or the DC side should be avoided.
- Keep the DC voltages between limits and alleviate any branch overloads.
- Accommodate varying power injections by renewable sources.
- Be robust with respect to disturbances in the HVDC grid.
- Coordinate the converters and allow provision of support to the adjacent AC systems in accordance with the requirements of each system (e.g. frequency support).

Compared to HVDC point-to-point links the power flow on an HVDC grid is not fully controllable, but will be distributed to the DC lines according to the laws of Kirchhoff. This is mainly a concern for meshed MTDC grids, but branch overloads could also result in radial MTDC systems following MTDC grid contingencies.

In addition, to ensure the correct operation of an HVDC grid it is necessary to maintain the DC voltages between tight limits. This is achieved by maintaining the balance between the total power imported into the MTDC grid and the total power exported from it.

As discussed in Section 6.2.4 of (CENELEC, 2020), the HVDC grid control supervisor is expected to be of a hierarchical structure, similar to how frequency is controlled in AC systems:

- The lower levels of control should be fast enough to cope with the fast dynamics in the HVDC system as well as able to ensure the stability of the system based on information readily available at converter level. Therefore this level should make limited (if any) use of communication means.
- The higher levels of control should have a view of the whole HVDC system and coordinate the converters in order to satisfy various objectives (e.g. desired power flow) at a slower time scale.
- Communication will play a vital role for the correct operation and coordination of the HVDC grid.

The exact specifications and strategies of the HVDC grid control are still an open question that has received important attention in the literature, but has not yet been implemented in a real system.

12.7.1.4. Coordination and Interoperability

Interoperability may be a major issue in future multi-vendor MTDC systems as vendor lock-in is not acceptable. The work conducted by CENELEC in (CENELEC, 2020) sets a first list of standards that should be respected, but additional requirements must be set in the future by the relevant TSOs and operators, such as clearly defining interfaces. The exchange of information and availability of simulation models is necessary to identify and solve such problems. Furthermore, increased coordination between the stakeholders of an MTDC grid is significant for its smooth operation.

According to (Rault, et al., 2018), interoperability (IOP) can be thought to rely upon three main pillars, shown in Figure 12-16. The definition of a structured MMC control architecture would allow accessibility to controls and references set points. The HVDC supervisor will monitor the system state, will control switchgear actions and coordinate MMC control mode and set point transitions. Interoperability will be ensured by a system integrator (who could be for example a TSO or consortium of TSOs) who will have the role to define functional specifications for the overall DC grid.

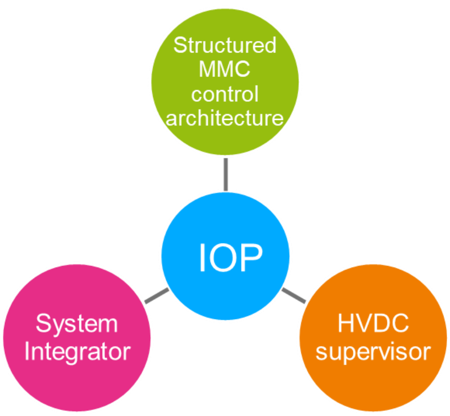


Figure 12-16: Possible main pillars of Interoperability

12.7.2. Guidelines for connection to HVDC grids

12.7.2.1. DC power and voltage

(a) Voltage ranges

The DC voltage level of HVDC grids serves as an indication of power balance in the HVDC grid. As a result, it bears a lot of similarities to the way AC frequency behaves in AC systems. Currently, there are no requirements defining the acceptable DC voltage ranges in an HVDC grid. Compared to classical HVDC connections, DC voltage variations are expected to be wider and more frequent following the extension to an HVDC grid, considering the increased number of possible operating points.

Therefore, as also discussed in (CENELEC, 2020), the HVDC converters and rest of the equipment should be able to operate in a wide enough steady-state DC voltage range. Wider ranges could be considered following an outage (e.g. N-1 operation).

Harmonization of DC voltage ranges would enhance the security of an HVDC grid and (subsequently) the adjacent systems.

(b) Maximum loss of power infeed/export to DC grid

A loss of power infeed to the DC grid will cause a voltage excursion. Adequate primary DC grid control via DC node droop voltage control and secondary DC grid controls would determine the maximum loss of power infeed to DC grid. This will therefore be a project-specific value. It has to be noted that automatic remedial action schemes might be used to increase the maximum allowed loss of power infeed to the DC grid.

The maximum acceptable loss of power infeed/export has to be determined and coordinated with primary and secondary DC grid control tuning and design.

(c) DC Power quality

The existing HVDC NC specifies clear requirements on AC power quality. DC power quality is expected to become more important following the extension to more complex, and most probably multi-vendor, topologies. For example, potential reasons to limit harmonic distortion in an HVDC grid include the correct operation of any connected HVDC converter, and limiting of losses (WG B4.68, 2020).

An acceptable distortion level on DC voltage should be established in order to ensure compatibility of the various equipment. The absence of such requirements could lead to costly re-design of equipment or additional filtering needs. The latter could be a major issue in offshore applications due to space constraints.

Any new equipment that is considered for connection to an HVDC grid should not cause unacceptable distortion. Therefore, acceptable distortion level has to be defined and harmonized.

12.7.2.2. DC Fault-ride through

(a) DC fault Ride-Through (DC FRT) and DC Over-Voltage Ride-Through (DC OVRT):

Defining similar envelopes on the DC side of the HVDC converters (as on the AC side) is important for the stability and security of both the AC and DC systems. For example, a converter tripping during high DC voltage could result in further increase of the DC voltages in the HVDC grid and (possibly) cascading outages. An example of possible temporary DC voltage envelopes that the DC equipment should endure is described in (CENELEC, 2020) and shown in Figure 12-17.

The harmonization of DC-fault ride-through requirements would facilitate the extension to multi-terminal DC grids.

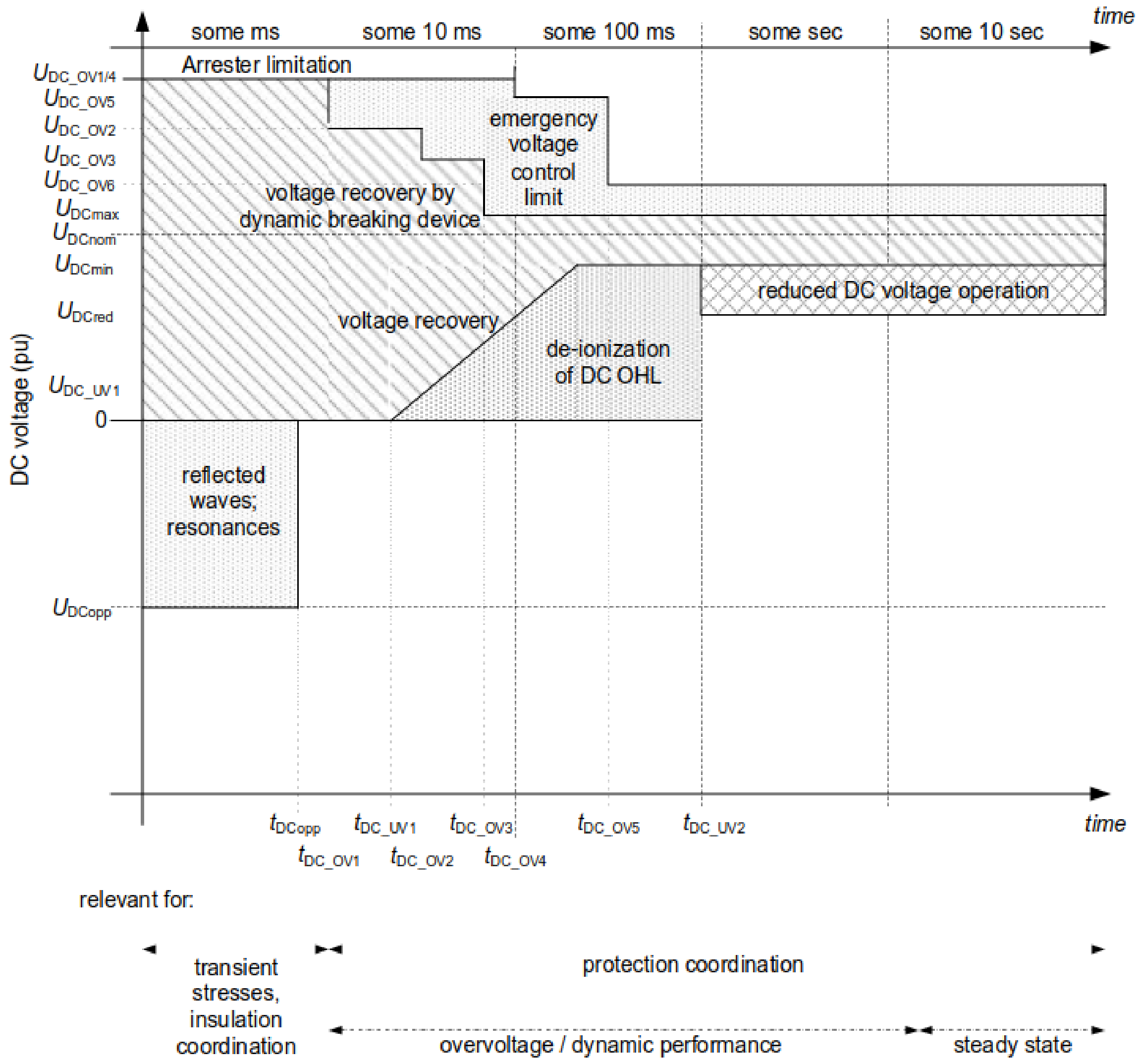


Figure 12-17: Example of temporary DC pole to ground voltage profiles in DC grids.

(a) Post-fault DC power recovery:

Any new equipment connected to the HVDC grid should be able to return to its pre-fault operating point as soon as possible following a DC fault, in order to minimize the impact of power interruption on the adjacent AC systems. In case the post-fault configuration of the MTDC grid does not allow the restoration of the power to its pre-fault levels (e.g. if a large OWF has been disconnected), an operating point with the minimal change should be pursued, as also discussed in Article 33.1 of the HVDC NC.

As briefly described in 12.7.1.2, the protection strategy will impact the active power flowing to the AC grid during a and shortly after a DC fault (up to 200ms). This temporary loss of power impacts HVDC converters not connected to the faulty line but located in the same protection zone (as described in (CENELEC, 2020)).

The exact determination of the DC power recovery requirements depends on the post-disturbance configuration, and could depend on the desired protection strategy. This requirement should be defined by the relevant TSOs or other operator.

DC power recovery requirements (recovery time and post-fault DC power) should be coordinated with the desired protection strategy and would therefore be project-specific. These requirements should consider the impact on both DC and AC grids.

12.7.2.3. *HVDC grid control and stability*

(a) Control requirements for onshore HVDC converters

Depending on the location of the converter and site-specific constraints, the HVDC converter should be able to operate in various control modes. For example, (CENELEC, 2020) defines, among others, AC voltage/reactive power control, Active power/DC voltage control and frequency/DC voltage droop control.

Focusing on the HVDC side, an onshore HVDC converter should be able to participate to DC voltage control, if requested by the operator of the HVDC grid. This participation should also satisfy pre-defined criteria, such as response time. However, as several publications in the literature have shown (Akkari, Dai, Petit, & Guillaud, 2016; Papangelis, Debry, Panciatici, & Van Cutsem, 2017), the DC voltage control may clash with other control schemes, such as AC frequency support. This emphasizes the fact that any DC voltage control requirements cannot be set independently from the requirements on the AC side of the converter.

Increased coordination between the relevant operators and stakeholders will be required to avoid conflicting requirements on AC and on DC side.

(b) Control requirements for remote-end HVDC converters

If the converter technology allows it, the remote-end HVDC converter should be able to provide support to DC voltage control by adjusting its power injection into the HVDC grid. Currently, the scope of a remote-end HVDC converter is simply to absorb the power generated by the DC PPM it connects to the MTDC grid, by setting the voltage and frequency at its AC bus. There is no requirement to participate in DC voltage control. However, this could be critical for the stability of more complex HVDC grids following DC contingencies. For example, the outage of an onshore converter during high offshore wind conditions could lead to insufficient onshore converter capacity to evacuate the offshore production.

Control or emergency mechanisms should be developed to coordinate the DC-PPM power adjustment in response to the DC voltage of the remote-end HVDC converter.

(c) Higher levels of hvdc grid control

This part is related to requirements that the higher levels of HVDC grid control should satisfy. Apart from any functional requirements and characteristics, such as the ones discussed in Section 12.7.1.3, other performance-related requirements might be imposed due to AC system constraints. For example, as discussed in Section 12.6.2.4 (i.e. on DC voltage and AC frequency control) the need to transfer power from a specific offshore DC PPM to a specific onshore converter in order to satisfy the FSM requirement of the HVDC NC might impose requirements on the higher level of the HVDC grid control.

In addition, the relevant TSO(s) and other operators should be able to adjust the settings of the higher levels of HVDC grid control based on the operating conditions (availability of converters, wind power production, etc.). Instead, internal converter controls subject to intellectual property rights of the manufacturer would remain a responsibility of the manufacturers.

Functionalities of the higher levels of HVDC grid control should be provided by the relevant TSOs (or HVDC system integrator) depending on the system needs.

(d) Control parameter changes

Following the connection of new equipment to an HVDC grid, it might be required to update the control settings of the connected converters. For example, the connection of a new HVDC cable and/or converter changes the HVDC grid characteristics. Specifically, it increases the total DC capacitance connected to the grid and may introduce new resonances due to cable dynamics. To avoid any adverse interactions or limit the need for additional equipment, the response characteristics of the converter controls should be adjustable within a pre-specified bandwidth.

Converter controls should be designed to be adaptable in a pre-defined range. Clear boundaries should be specified between the parameters available to be adjusted by the relevant TSO (or HVDC grid integrator) and the ones available only to the vendor.

12.7.2.4. DC grid restoration from blackout

In case of a full blackout of the HVDC system, it needs to be re-energized. The most probable preferred option would be to re-energize from an onshore synchronous area, as discussed in Section 5.7.3 of (CENELEC, 2020). However, if deemed relevant by the TSOs, enabling restoration from any converter stations should be considered.

If requested by the relevant operator (TSO or non-TSO), HVDC systems should be able to be restored in a timely manner from any converter station.

12.7.2.5. Protection devices and settings

The location, design and settings of the protection devices will depend on the recommended protection strategy and allowed impact on the onshore grid. It has to be noted that costs of protection devices for an offshore DC grid are significantly higher than for an AC grid. Therefore, the need for fully selective fault-clearing strategy might not be the most economic option and is likely to be decided on a project-by-project basis.

In (CENELEC, 2020), the concept of the "protection zone matrix" is used as a guideline on how to design the protection of an HVDC grid. The main idea is to assign each converter station (or part of the HVDC grid) a desired behaviour in response to a fault at each location in the HVDC grid. The desired behaviour is usually specified based on AC system stability constraints and could be one of the following:

- Continued operation during the fault and fault separation,
- Temporary stop of active power,
- Temporary stop of active and reactive power,
- Permanent stop of active power,
- Permanent stop of active and reactive power.

Then, depending on the desired behaviour the HVDC system protection scheme can be configured appropriately.

It is important to note that there might be some interactions between HVDC converter and DCCBs, the protection strategy should therefore be communicated to manufacturers in order for them to design/tune their equipment.

The relevant TSOs (or HVDC system integrator) should define and coordinate the protection strategy for each project. The expected locations of DCCBs and any other necessary equipment should be provided. Increased coordination in planning is necessary in order to allow for adjustment of the protection strategy following possible future extensions (e.g. additional DC breakers).

12.7.2.6. Information exchange and coordination

(a) Standardized converter interface

In order to facilitate interoperability and compatibility, it is important to have a standardized interface for this secondary DC grid controller. Currently, no standardized interface exists, but steps have already been taken in [3].

A standardized interface between the HVDC converters and the secondary DC-grid controller would be required. However, further investigations are needed. Good examples are the ENTSO-e paper on standard control interface [3] or the recent CIGRE working group on "Interoperability in HVDC systems based on partially open-source software".

(b) Control interactions

Control interactions might occur on the DC side, (e.g. between converters and HVDC circuit breakers, or between converters during DC power recovery after a fault). As a result, coordination is required between the planning of the DC grid, the design of the converters and their control.

Solving control interactions is a non-trivial task not only from a technical point of view, but also in terms of responsibility. Namely, the interactions would require adjustment of settings of the HVDC equipment, a part of which is usually not disclosed due to Intellectual Property (IP) restrictions. From the consultation with relevant stakeholders throughout this project, there is a consensus that the IP of the vendors has to be protected. This poses challenges in studying and resolving adverse control interactions and interoperability issues. The work in the BestPaths project (BestPaths, 2018) has proposed a procedure to address such issues while respecting IP in a multivendor environment, however there is currently no accepted methodology.

It must be verified that any new DC grid expansion does not cause adverse interactions with the existing assets. Standardization on the methodology to study such interactions studies is required.

(c) Simulation models

The recommended follow-up actions concerning Article 54.1 of the HVDC NC (see Section 12.6.8.3) are also applicable for the DC point of connection of an HVDC converter. Relevant simulation models should be provided to the TSOs. These models may be of several types (load flow, electro-magnetic transient, electro-mechanical transient, power quality, hardware in the loop, etc.) and should include an adequate level of detail. If encrypted models are provided, a functional description of the controls, inputs and outputs should be detailed. A list of the models has been also proposed in (CENELEC, 2020).

The importance of real-time replicas may be even greater for HVDC grid studies with multiple vendors in order to identify any interoperability or other issues that cannot be captured from offline simulation studies.

It is recommended that the TSOs harmonize the required types of simulation models and expected level of detail through the publication of a common modelling guideline for HVDC systems.

Compared to PoC-AC, an agreed framework on the use of replicas might be even more important to identify DC-side problems when considering extension to more complex HVDC topologies.

(d) Model validation and compliance simulations

Model validation refers to the process of verifying whether the models provided represent in a sufficiently detailed manner the reality. Compliance simulation refers to the process of verifying technical functionalities/capabilities using the simulation model provided. As also stated in (CENELEC, 2020), a “fit-and-forget” approach might not be sufficient for HVDC systems. Instead compliance simulations should be performed through the lifetime of the HVDC system, especially after integration of new equipment or topology adjustments.

Harmonized guidelines between TSOs for both model validation and acceptance testing would be very beneficial for facilitating the development of HVDC grids. Compliance studies may be needed throughout the whole lifetime of the HVDC system.

12.7.3. Summary table

Section	Topic	Challenge	Proposed guideline
12.7.2.1(a)	DC power and voltage	DC Voltage range	Harmonization of DC voltage ranges would enhance the security of an HVDC grid and (subsequently) the adjacent systems.
12.7.2.1(b)	DC power and voltage	Maximum loss of power infeed to the DC grid	The maximum acceptable loss of power infeed/export has to be determined and coordinated with primary and secondary DC grid control tuning and design.
12.7.2.1(c)	DC power and voltage	DC power quality	Define and harmonize acceptable distortion level in the DC grid.
12.7.2.2(a)	DC fault-ride through	Fault-ride through envelopes	The harmonization of DC fault ride-through requirements would facilitate the extension to multi-terminal DC grids.
12.7.2.2(a)	DC fault-ride through	Post-fault DC power recovery	DC power recovery requirements (recovery time and post-fault DC power) should be coordinated with the desired protection strategy and would therefore be project-specific. These requirements should consider the impact on both DC and AC grids.
12.7.2.3(a)	HVDC grid control and stability	Control requirements for onshore HVDC converters	Increased coordination between the relevant operators and stakeholders will be required to avoid conflicting requirements on AC and on DC side.
12.7.2.3(b)	HVDC grid control and stability	Control requirements for remote-end HVDC converters	Control or emergency mechanisms should be developed to coordinate the DC PPM power adjustment in response to the DC voltage of the remote-end HVDC converter.
12.7.2.3(c)	HVDC grid control and stability	Higher levels (secondary and tertiary) HVDC grid controls	Functionalities of the higher levels of HVDC grid control should be provided by the relevant TSOs (or HVDC system integrator) depending on the system needs.
12.7.2.3(d)	HVDC grid control and stability	Control parameter changes	Converter controls should be designed to be adaptable in a pre-defined range. Clear boundaries should be specified between the parameters available to be adjusted by the relevant TSO (or HVDC grid integrator) and the ones available only to the vendor.
12.7.2.4	DC grid restoration from blackout	Restoration after full black-out of the HVDC system	If requested by the relevant operator, HVDC systems should be able to be restored in a timely manner from any converter stations.
12.7.2.5	Protection devices and settings	Choice of the protection strategy	The relevant TSOs (or HVDC system integrator) should define and coordinate the protection strategy for each project. The expected locations of DCCBs and any other necessary equipment should be provided. Increased coordination in planning is necessary in order to allow for adjustment of the protection strategy following possible future extensions (e.g. additional DC breakers).

Section	Topic	Challenge	Proposed guideline
12.7.2.6(a)	Information exchange and coordination	Standardized converter interface	A standardized interface between the HVDC converters and the secondary DC grid controller would be required. However, further investigations are needed. Good examples are the ENTSO-e paper on standard control interface [3] or the recent CIGRE working group on “Interoperability in HVDC systems based on partially open-source software”.
12.7.2.6(b)	Information exchange and coordination	Control interactions	It must be verified that any new DC grid expansion does not cause adverse interactions with the existing assets. Standardization on the methodology to study such interactions studies is required.
12.7.2.6(c)	Information exchange and coordination	Simulation models	It is recommended that the TSOs harmonize the required types of simulation models and expected level of detail through the publication of a common modelling guideline for HVDC systems. Compared to PoC-AC, an agreed framework on the use of replicas might be even more important to identify DC-side problems when considering extension to more complex HVDC topologies.
12.7.2.6(d)	Information exchange and coordination	Model validation and compliance simulations	Harmonized guidelines between TSOs for both model validation and acceptance testing would be very beneficial for facilitating the development of HVDC grids. Compliance studies may be needed throughout the whole lifetime of the HVDC system.

Table 12-9: Summary Table for Gap Analysis - Guidelines for Connections to HVDC Grids

12.8. Connection to AC HUB

Disclaimer: no connection code including AC hubs exists. This companion guide proposes some guidelines which can be seen as suggestions and starting points for future discussions.

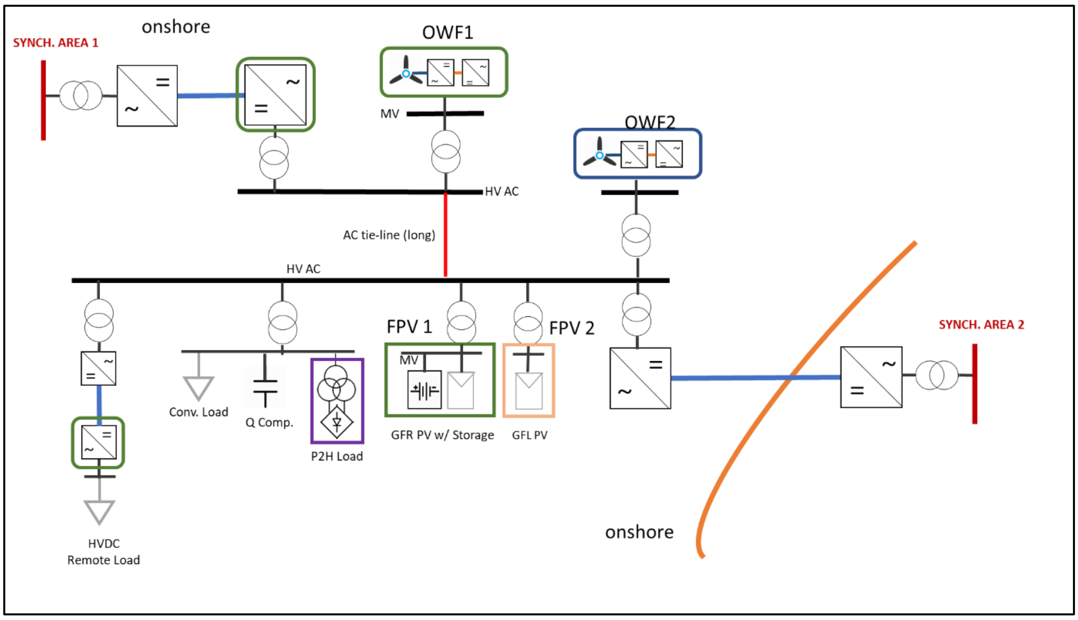
Important part of the section focuses on requirements for Grid Forming functionalities in PEIPS. Grid Forming technology is still under research and not fully mature, whereas industry has vast experience with the requirements and performance of synchronous generators and synchronous condensers.

12.8.1. Description of an AC Hub and the need of new requirements

12.8.1.1. Description of an AC hub

AC hubs are offshore islanded grids that allow the connection of several generation and load assets. They are enabled by HVDC interconnectors. In the future, it is expected that offshore wind power plants could be interconnected by AC hubs, where other kind of generation[4] (e.g floating PV or storage) is connected to the grid.

In AC hubs, converter-based generation could dominate (up to a 100% penetration). AC hubs are also expected to interconnect a variety of loads. Examples of loads can be Power-to-X technologies or Green Hydrogen production. Traditional offshore loads such as the ones linked to the Oil and Gas exploitation activities may be also connected to an AC hub, using an AC link or a even a point-to-point HVDC connection. **A simplified diagram showing a generic structure of an AC hub is shown in Figure 12-18.**



[4] The fact that synchronous Generators and Condensers could be part of an AC hub is considered in this document. However, the industry is leaning towards power-electronics interfaced solutions. In our opinion, it is expected that the penetration of rotating machines in AC hub will be limited.

Figure 12-18: Generic Structure of an AC hub based Hybrid project: Wind, PV and Storage as well as conventional and P2X loads are included.

The objective of this chapter is to identify the gap on minimum requirements for connection of generators and loads to the AC hub. This is done via a gap analysis from existing European Connection Network Codes.

The European Connection Network Codes cover three main topics:

- Requirements for Generators (RfG)
- the Demand Connection Code (DCC)
- the HVDC Network Code.

These codes have been conceived having in mind the traditional characteristics of a synchronous area. **Today, there are no specific requirements for generators or demand connected to AC hubs**. For HVDC converters, some limited aspects are covered in the HVDC NC requirements for "remote-end HVDC".

12.8.1.2. Using the Existing NCs as base for AC hub Requirements

Directly translating the existing Network Codes and expanding their applicability to AC hubs could be argued in order to benefit for the years of experience on traditional AC systems. However, traditional Synchronous Areas are inherently different than AC hubs. A non-exhaustive comparison of their main technical characteristics is given in the Table 12-10.

	'Classic' Synchronous Area	'Future' Offshore AC Hubs
CHARACTERISTIC FACTOR	Synchronous Generator Dominated	Converter Dominated - up to 100%
	Mainly Grid Following Converters	Grid Forming Converters May Dominate
	Strong Grid. High Short-circuit power from Synchronous Generators	Weak Grid. Short-circuit current limited by Converter Capabilities
	Abundant Mechanical Inertia	Zero or extremely low Mechanical Inertia
	Operation at nominal frequency is mandatory (50 Hz or 60 Hz)	Design freedom when choosing operating frequency. Operation off-nominal frequency may be desirable.
	Frequency is physically interlinked to power unbalance	Frequency is imposed or governed by Grid Forming Converters
	Highly Interconnected	Weakly interconnected. Radial network is possible.
	System restoration is an exceptional procedure	Start-up of the AC hub could be a more common procedure
	System Restoration is mainly thought from conventional units to the load.	Restoration from OWPP may be desired.
	Limited Energy Storage	Energy Storage may be a core part or functionality of the AC hub
	Phasor mode simulation is effective for system-wide analysis. Open standard models. Vast experience with testing and validation of models.	EMT simulation is needed. Blackbox and manufacturer-specific models. Confidentiality issues.

Table 12-10: Brief comparison of Synchronous Areas and Future AC Hubs

In fact, the table above reflects up to some extent challenges that Synchronous Areas will face in the view of TSOs and other stakeholders. Aware of these issues, the MIGRATE project (H2020 Project MIGRATE) conducted a survey among different TSOs. The results of the survey show that most challenges arise from a heavy power-electronics interfaced asset reliance. On a similar way, National Grid and the University of Strathclyde (Ierna & Roscoe, 2017) have similar conclusions on the challenges to be faced by high power electronics penetration. Even though terminology may not be exactly the same, these challenges are fully in line with literature from IEEE (IEEE PES/NERC TF on IBR, 2018) (Matevosyan, et al., 2019).

Given the new challenges described above, if a direct translation of the existing network codes is done, some negative consequences may arise:

- Overly strict requirements that impose unnecessary design constraints.
- Requirements that are out of scope or not applicable
- New constraints that arise due to AC hub characteristics that are left out.

Given the above, a solution could be to start from scratch and write specific Network Codes only applicable for the AC hub. This would however be very inefficient as current Network Codes embed years of consolidation among experts and different relevant parties. Adapting the actual Network Codes, taking into considerations the specificities of an AC hub, may be therefore the preferred option.

The aim of this section is to propose a **Gap Analysis among the existing Network Codes and devise what are the attention points required for translation in the AC Hub**. The chapter is divided in 3 sub-sections, as per the current structure of the existing Network Codes.

- Remote-end HVDC Converters in AC Hubs → GAP analysis of NC HVDC
- Generator Connection in AC Hubs → GAP analysis of NC RfG
- Demand Connection in AC hubs → GAP analysis of NC DCC

12.8.2. Challenges in the AC hub

Assets in an AC hub shall operate in harmony with each other in a wide range of conditions. The outage of one asset (planned or forced) shall not jeopardize the stability of the complete AC hub, nor the stability of the Synchronous Areas on which the AC hub is interconnected. An AC hub could be composed by the assets listed below:

- **HVDC links:** Most probably VSC-based, good candidates for assuming the task of forming the grid.
- **OWPPs:** AC connected. Could be grid forming or grid-following.
- **Converter-based generation (non-wind) and/or storage:** e.g. Floating PV or battery storage. Usually grid following, potentially grid forming.
- **Conventional Loads:** With power quality and reliability requirements.
- **P2X loads:** In particular, Power to Hydrogen loads. Even though challenges regarding hydrogen logistics exist, offshore AC hubs could enable to produce green hydrogen with wind power surplus. This has been an interesting concept explored by some utilities5.
- **AC tie-lines:** interconnecting two or more parts of the AC hub.
- **Conventional generation:** penetration expected to be rather limited.

The AC hub as a whole, or interlinked-HVDC system, can be considered as a hybrid project as it can transfer power from one synchronous area to another via the HVDC links connected to it.

Technical requirements for HVDC converters, Generators and Power Park Modules and AC connected load in the AC hubs shall ensure that both normal operation and a wide range of incidents can be manageable without unacceptable consequences. These technical requirements should cover, amongst other, the following situations:

- Normal Operation: mainly balancing of the AC hub
  - Generation fluctuation in the OWPP and others
  - Load fluctuation in the AC hub
  - Power Transfer fluctuation between the connected synchronous areas
  - Start-up and shut down of assets (normal conditions)
  - Change of setpoints
- Incidents outside the frontier of the AC hub
  - Fault in one of the Synchronous Areas
  - Energy unbalance in one of the Synchronous Areas
  - Disconnection from the Synchronous Area (e.g. short-circuit /incident in the onshore converter station)
  - Temporary or permanent loss of HVDC link (incident in the remote-end converter or in the DC line)
- Incident inside the frontier of the AC hub:

[5] https://www.greentechmedia.com/articles/read/orsted-to-power-decarbonization-hub-for-land-sea-and-air-transport

- Fault in one of the assets in the AC hub
- Disconnection of one of the assets in the AC hub
- Split of the AC hub (e.g. trip of the AC tie-line)

In summary, an AC hub should be able to operate with a wide range of assets and in a wide range of conditions. It should withstand a variety of incidents without unacceptable impact. Reaching this goal could be facilitated by recommending a minimum level of performance in the assets connecting to the AC hub.

The aim of this section is not to establish specific technical requirements but to illustrate, exemplify and recommend guidelines, based in previous technical work and existing connection network codes. **The first step is to provide an overview of the challenges that arise in an AC hub.**

12.8.2.1. Degree of Participation in the AC hub Stability

In a Synchronous Area, the contribution of synchronous machines to system stability is split according to relative importance and location of the generators (MVA size and connection point voltage). In an AC hub, how to share the contribution between each asset is still a key challenge to be solved.

- Early AC hubs would be rather limited in size[6] and number of assets in comparison to Synchronous Areas. This would allow the use of centralized or decentralized controls for ensuring stability of the AC hub.
- The requirements for each PEIPS in the AC hub could be different for normal, alert or emergency operations. The split of participation will be most likely project-specific and therefore still remains an open question.

The approach used to provide the necessary means for stable operation, should be taken in a coordinated, pre-defined way.

12.8.2.2. Forming the Voltage

In Synchronous Areas, the voltage is formed by rotating synchronous generators. As PEIPS would be the dominant asset in an AC hub, forming the voltage sine wave is a task that shall be delegated to the most important converters in the Hub. Examples of grid forming capability definitions can be found in the literature:

- The National Grid VSC Draft Grid Code released early 2020 (National Grid, 2020) establishes minimum requirements for the grid forming functionality: “shall be capable of operating as a voltage source behind an effective reactance or be capable of supplying Inertia Power into the Total System over a frequency band of 5Hz to 1kHz before, during and after a fault”
- PPMs or HVDC Converter Stations as “capable of supporting the operation of the ac power system (from EHV to LV) under normal, alerted, emergency, blackout and restoration states without having to rely on services from synchronous

[6] Up to 10-15 GW in some cases.

http://www.multi-dc.eu/wp-content/uploads/2019/09/FitimKryezi_NSWPH-and-the-Role-of-Interconnections.pdf generators" have been defined in the ENTSO-E Technical Report (ENTSO-E). They have been named Class 3 PPMs or HPMs.

In practice, the most suitable converters would probably be the offshore HVDC VSC converters as they are relatively important in size and can transfer energy from their respective synchronous areas. However, grid forming capabilities have been also demonstrated in battery storage and wind turbine converters (Brogan, Knueppel, & Elliott, 2018; Roscoe, Brogan, Elliott, & Knueppe, 2019).

The guidelines for AC hubs should define what is a grid-forming converter and how it is expected to behave. Even though certain assets are more suited to the task of grid forming, the guidelines should leave the door open to allow grid-forming capability from sources different than the offshore HVDC converters and Offshore wind parks. Minimum high-level expected performance should be recommended without imposing specific control principles.

12.8.2.3. Providing System Strength

In a Synchronous Area, system strength and short-circuit current come predominantly from the natural response of synchronous generators. Converters are inherently limited in current, thus have a limited contribution to system strength. The following challenges have been identified from the perspective of limited System Strength:

- Remote-end HVDC VSC Converters and other Grid Forming Assets (if any) should be able to provide sufficient system strength for conventional and power-electronics based loads and generators to work in a stable way.
- Assets (loads and generators) connecting to the AC hub should be able to operate in a stable way, considering the inherently low system strength that exists in an AC hub. Specific attention should be paid on synchronization of converters, energization of transformers and other phenomena that could impose specific requirements on system strength.
- Some faults could result in the split of the AC hub in two isolated AC areas (e.g. permanent fault on an AC cable). This should not result in a permanent outage or impossibility to operate given the lower system strength. Provision for operation at lower capabilities could be made if operation with the split AC hub is still possible.
- Assets participating in the formation of the grid, in particular remote-end HVDC converters, should do it in a coordinated way.
- System strength should be sufficient to make the detection and clearing of AC faults possible.
- Increase the fault current provided by HVDC converters. As it is recurrent practice for power systems, converter ratings could have different transient and steady state ratings. However, depending of the specifics, this could result in increased costs as oversizing of the power hardware may be needed. Table discusses the impact of specific requirements linked to system strength on PEIPS design.

Synchronous condensers or generators are also good candidates for providing system strength. Requirements for these assets are already mature and exist in the network codes.

Examples of functional requirements for GFM IBPS	Affected product aspect of GFM BPS compared to GFL IBPS		
	Is higher current capability required? (Hardware)	Is energy buffer needed? (Hardware)	Are control algorithm changes needed? (Software)
Fast active power variations	Potentially	Yes	Yes
Response to grid voltage vector shift	Yes	Yes	Yes
Inrush current	Yes	No	Yes
Fault current contribution	Yes	No	Yes

Table 12-11: Impact of functional requirements for Grid Forming PEIPS to their design (hardware/software) - source (Matevosyan, et al., 2019)

The guidelines for AC hub connection should ensure that sufficient system strength is present for safe operation of the system, in normal and incident conditions. Loads should not subject the system to high currents beyond system capabilities (e.g. inrush).

It should be taken into consideration that higher strength from PEIPS could be linked to higher cost as components oversizing may be required.

12.8.2.4. Inertia and RoCoF

In Synchronous Areas, inertia and frequency control would come predominantly from Synchronous Machines. In an AC hub, frequency control would be predominantly determined by the grid-forming controls of PEIPS.

The following challenges have been identified from the perspective of lack of inertia and control-dependent frequency behaviour:

- To provide instant power to suddenly changing loads in an electrical power system, there is a need for PPMs and HVDC Converter Stations with a voltage source characteristic (Grid Forming)
- Grid-forming converters should control frequency in a coordinated way among them. The control strategy to be used should be freely chosen but the system dynamics should be designed in a compatible way allowing loads and other grid-following equipment in the AC hub to operate safely within their boundaries.
- As the AC hubs could be relatively small in size with respect to synchronous areas, the use of control strategies that require communication is a valid possibility (e.g. master-slave). However, the requirements should not impose one strategy or the other and should allow the use of control strategies that only use local measurements (e.g. droop control)
- Assets not controlling frequency should not impose unnecessarily tight limitations to the way frequency and RoCoF vary in the AC hub.
- Notwithstanding the above, technical limitations inherent to the technology of the assets should be taken into account when coordinating the frequency control and RoCoF.

If support from synchronous machine is widely available, these challenges will be most probably mitigated.

As the frequency is now determined by Grid Forming PEIPS control strategy, coordination between all types of assets is essential to ensure stability. Coordination can come from communication between assets or by using decentralized control strategies.

Loads should not impose technically unjustified constraints in the frequency dynamics of the AC hub.

Setting the expected minimum performance of grid-forming controls affecting frequency (speed, duration) could ease the coordination process of frequency control in the stability of the AC hub.

12.8.2.5. Disturbance ride-through

Faults in the Synchronous Area will impact to some extent the DC link and then the AC hub. Mechanisms should be foreseen, to avoid tripping of assets in the AC hub given faults in the Synchronous Area.

Faults in the DC link of the HVDC system will, most-likely, result in either a temporary or permanent interruption of power transfer. It should be assured that in case of temporary faults, the AC hub continues to operate in an stable way or that at least, full restoration can be promptly achieved after the restoration of the DC link.

Guidelines that cover the behaviour of PEIPS and HVDC converter station during faults could cover the following:

- Interlinked HVDC systems via the AC Hub should be able to operate in a stable way, in case of incidents in neighbouring HVDC systems. Incidents in one of the (radial) HVDC system should not affect the operation of the remaining (radial) HVDC links in a degree that operation is endangered.
- The impact of faults in the AC hub to the Synchronous Area should be limited as much as possible.
- Faults in the AC hub should not result in the cascaded or mass disconnection of AC connected assets. This is covered to some extent by the LVRT curves.
- Behaviour during and after the fault, especially for grid forming converters. Technical characteristics of the PEIPS and HVDC Converter Station during and after fault such as PWM blocking, active power recovery, overcurrent behaviour should be coordinated. Guidelines could ease the task of coordination. The National Grid VSM Draft Grid Code identifies when a PPM is to enter fault mode (U = 0.85 pu) and its duration (up to 0.5 [s])
- Grid forming assets should provide an injection of fault current (limited to the converters' overcurrent capacity). Research has suggested that the speed and timing of this current injection is essential for system stability. Literature suggest that a substantial response within a quarter of a wave cycle is the required performance of grid forming converters for a 100% power electronics system (Weise, Korai, & Constantin, 2019). This is backed up by the definition of instantaneous support in the VSM Draft Grid Code.
- Current limitations of grid forming assets have to be managed in a suitable way to limit fault current below rated current. It is not yet clear what is the best strategy for prioritization (active or reactive power) during faults. The National Grid VSM Draft Code allows for current limitation while maintaining the fault current phase angle.
- The grid forming converters must protect themselves during faults to avoid damaging the power hardware. This means that when faults result in a surplus of active power, the correct means for energy dissipation must be considered (e.g. DC chopper).

Assets (generators and loads) in an AC hub should be capable of riding through faults while supporting the voltage in the grid. The impact of a fault should be limited as much as possible to the asset itself, even though is not always possible as the overall power balance must be maintained. When incidents occur, grid forming assets should react in a controlled and predictable way. Their performance should be fast enough to maintain stability in the system.

When reaching their limits, grid forming assets should protect their power hardware from damage. When different functionalities demand contradicting control actions, a priority should be established (e.g., Article 14.5 c) (European Commission, Network Code on Requirements for Generators,

12.8.2.6. Adverse System Interactions

An AC hub could face interactions between controllers as the converters are connected to a low system-strength grid. PEIPS are also a potential source of harmonic pollution.

- Grid Forming Strategies shall be coordinated to be compatible and ensure the stability of the grid.
- Specific studies can be executed to ensure that the operation of the AC hub is secure and asset interaction does not endanger the stability of the AC hub nor the HVDC system connecting to it.
- Long AC cables in a weak AC hub could result in further adverse interactions (between the cable and the rest of the AC hub) that have to be addressed.
- If studies show risk of undesirable interactions from the connection of an asset, a suitable technical solution (e.g. compensation equipment or changes to the controls) must be provided/installed.
- PEIPS in the AC hub could potentially act as sinks for harmonics and inter-harmonics in the system voltage, as well as measures to counteract imbalances in the grid (ENTSO-E). A sink for harmonics means that the grid-forming or even grid-following inverter is capable to absorb external harmonic currents without modifying its fundamental behaviour. This capability should not come at the expense of other dynamic stability-related capabilities such as fault ride through.

Undesired interactions must be prevented by means of detailed studies, control tuning and use of compensation equipment. As it is covered by actual Network Codes, the inherent capability of oscillation damping could be an integral part of AC hub controls.

Assets in the AC hub could have the responsibility of keeping high power quality not only by avoiding the injection of harmonics, but actually being able to correct them.

12.8.2.7. Protection System Impact

Most of the AC protection systems rely on high short-circuit currents to detect and isolate the fault. Furthermore, AC protection systems have typically hundreds of milliseconds to act before stability is lost. This may not be the case in an AC hub as both short-circuit current and stability margins may be reduced.

- Assets connecting to the AC hub should use a protection strategy that allows selectivity and reliability. This should be the case even though AC hub design results in low short-circuit currents.
- Fault clearing time should be coordinated with AC hub transient stability limits imposed by the capability of the grid forming converters and the control strategy used.
- Backup and redundancy of the protection scheme should take into account the much shorter transient stability limits in an AC hub.
- Protection of hardware components of PEIPS is mainly done by control means. Mechanisms should be in place to ensure that the hierarchy of protections is correct and that there are no conflicts between them. This was also raised in the Disturbance Ride Through challenge and treated in Article 14.5 c) (European Commission, Network Code on Requirements for Generators, 2016) and Article 35.2 (European Commission, Network Code on HVDC Connections, 2016) of the Network Codes.

Adequate power system protection methods that do not necessarily rely on short-circuit current will be required in AC hubs. Probably, the speed requirements will be even higher than in today's synchronous areas, as transient stability limits will be tighter. Selectivity and reliability requirements are to be comparable with current AC grids.

12.8.2.8. Power balance control during contingency conditions

Given the nature of generating sources in the AC hub, power unbalance containment in contingency conditions will probably require demand-side management or curtailment.

- A single incident could result on an AC hubs losing an important share of their power infeed (e.g. outage of OWPP or HVDC converter station feeding the hub). Quickly restoring the power balance is very important for system survival. Load is deemed to play an important role in this tasks.
- Traditional Underfrequency and Undervoltage Load Shedding Schemes (UFLS and UVLS) require a minimum systems dynamic response to be effective in preventing system collapse. ENTSO-E (ENTSO-E) states that the Low Frequency Demand Disconnection (LFDD) may be unsuccessful in being a last-resort scheme if system collapse is faster than the actuation of the scheme. It must be ensured that LFDD implementation and system dynamics are compatible.
- In AC hubs, load disconnection or generator curtailment could be communication-based and controlled by a centralized controller, in order to be faster acting. Requirements should leave the door open for that possibility.
- In addition to traditional UFLS and UVLS Schemes, demand-side management and load flexibility could be an effective way to stop system collapse as long as the system dynamics are slow enough for them to act.

Load disconnection schemes in AC hubs have to be coordinated with respect to the specific AC hub dynamics. It is important that in the event of a high power imbalance incident, sufficient time is given for load disconnection to act. Fast-acting communication-based demand response schemes could be considered to improve the performance of load shedding and generator curtailment schemes.

12.8.2.9. System Restoration

The collapse of a Synchronous Area is an extreme and rare event. Currently, there is no operational experience of AC hubs to provide indication on how often it would experience collapse. However, due to its considerably smaller size compared to synchronous systems, and to be on the conservative side, it would be reasonable to consider that the AC hub restoration could be a more common procedure.

- System restoration of the AC hub could come not only from HVDC offshore converters, but also from the OWPP or other assets with black-start capability.
- The AC hub could also provide system restoration capabilities to the HVDC systems and even to the connecting synchronous areas if requested and agreed between the relevant TSOs and other non-TSO operators.

In AC hubs, system restoration could be a more recurrent procedure than in present-day AC systems. Any future requirements should not exclude several assets from being involved in AC system restoration or in Synchronous Area restoration from the AC hub.

12.8.2.10. Simulation Models

Phasor-based simulation has been widely used for the security analysis of large power systems. Models are widely available and vast experience exists regarding validation of model behaviour. Most of the time, models from manufacturers of synchronous generator controls are open and described via standard block diagrams. This makes the integration of particular asset models into a common database an easier task. The reality of an AC hub diverges from the practices established up to now:

- EMT simulation is required to evaluate the potential interaction between high bandwidth controllers in PEIPS, HVDC converter stations and converter-interfaced loads.
- Stability related issues are linked to a much faster nature. Models need to accurately represent fast controllers that are neglected when using phasor mode simulation.
- Models contain proprietary information about control strategy of the asset that are usually encrypted ("black-box"). Up to our knowledge, standardized EMT model availability is very limited and, in several cases, of low applicability, as they may neglect manufacturer-specific characteristics of the controls.
- Real-time replicas of the equipment connected to an AC hub might be also necessary, for the same reasons described in Sections 12.6.8.3 and 12.7.2.6(c), especially until sufficient trust to the offline models (i.e. phasor and EMT) has been built.

Minimum requirements for validation of EMT models could be recommended. Investing efforts in the development of standardized models that allow to represent the most common types of grid forming converters and their control strategies could prove valuable to facilitate the integration of multi-vendor /multi-owner systems in AC hubs. The use of real-time replicas should be considered, if possible.

12.8.3. Requirements for Generators in AC hub

As discussed in the introduction, European Connection Network Codes were envisioned for Synchronous Areas and not for islanded and/or non-synchronous networks. However, they serve as a starting point that allows to shed light on potential future requirements for an offshore AC hub.

Several categories of challenges were discussed, it is expected that the future Requirements for Generators in AC hubs can serve to overcome those specific challenges. The aim of this section is to perform a gap analysis on the existing Network Connection Code – Requirements for Generators based on the actual requirements, and the specific challenges for the AC hub. This is shown in the schematic of Figure 12-19.

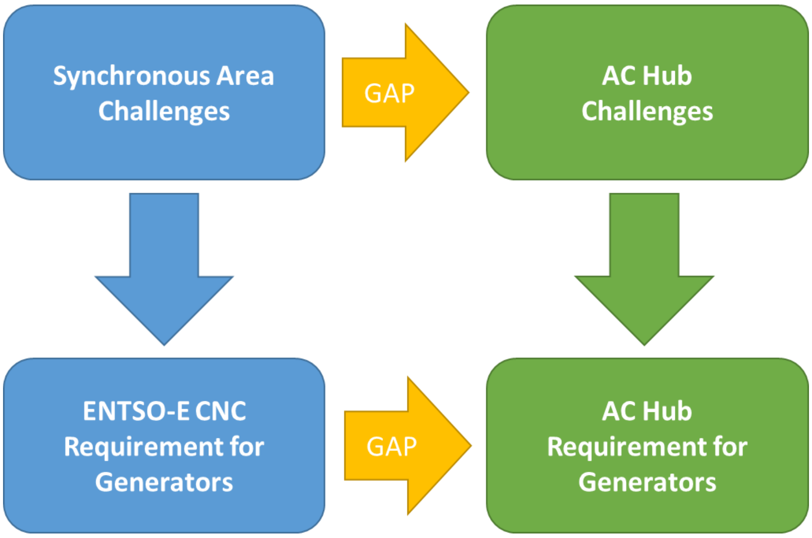


Figure 12-19: Gap Analysis on the ENTSO-E CNC RfG based on AC Hub Challenges

12.8.3.1. General Provisions

NC RfG Article No.	Article Topic	Challenges	Potential Gap
5	Classification / Significance	Degree of Participation in the AC hub Stability	Current classification of Type A,B,C,D may not be suitable for AC hubs. ENTSO-E classification proposed in (ENTSO-E) may be a good starting point.

Table 12-12: RfG Gap Analysis for AC Hub – General Provisions – Summary Table

(a) ARTICLE 5 - DETERMINATION OF SIGNIFICANCE

GAP DIAGNOSIS:

The current RfG assigns a degree of strictness in minimum requirements on system stability with respect to generator size and nominal voltage at the connection point. The direct application of this criterion on AC hubs is not recommended as voltage level and size of units are inherently different than in a Synchronous Area. While in large synchronous areas, the size of generating units varies significantly (e.g. from 1 MW PV units up to 1000 MW nuclear plants), the sizes in AC hubs will not be so different. Therefore, adapting this classification, implementing a new one or even abandoning completely such a classification based on size could be envisaged.

PROPOSAL TO CLOSE THE GAP:

A classification method based on system relative size and capabilities may be more relevant in an AC hub. Specifically, as far as power electronics-interfaced power sources are concerned, a classification according to their grid-support capabilities may be more suitable. The relative size of the installation respective to the total HVDC remote-end terminal power rating could be the second criterion. A minimum share of “Class C” grid forming devices could be defined.

More research is recommended on how to assign responsibilities regarding the stability on generating units connecting to the AC hub. Aligning to the classifications of the ENTSO-E high penetration of PEIPS Expert Group is one alternative.

12.8.3.2. General Requirements

NC RfG Article No.	Article Topic	Challenges	Potential Gap
13.1	Frequency Ranges for Operation	Inertia and RoCoF	The recommendation needs to take into account the wider frequency capability of PPMs as well as off-nominal frequency operation.
13.2	LFSM-O	Inertia and RoCoF	AC hubs could require faster performance (not only in terms of initial delay). Communication-based power reduction may be needed to keep system stability.
13.4	Power Reduction due to Underfrequency	Inertia and RoCoF	Requirements could be even stricter, if needed at all. A similar guideline that covers the reduction of voltage could be envisaged.
13.6	Cease Active Power Injection	Inertia and RoCoF	AC hubs could need a much faster response from PPMs.
14.3	LVRT profile	Disturbance Ride-Through Capability	It might be important to cover actual grey zones regarding the blocking of converters during faults.
15.2(c) and (d)	LFSM-U / FSM	Inertia and RoCof	Similar to article 13.2, AC hubs could require faster performance (not only in terms of initial delay). Communication-based power reduction may be needed to keep system stability.

Table 12-13: RfG Gap Analysis for AC Hub – General Requirements – Summary Table

(a) ARTICLE 13.1 – FREQUENCY RANGES

GAP DIAGNOSIS:

Currently, the RfG requires very strict ranges based on the characteristics of synchronous units. Imposing these narrow operational ranges in an AC hub could result in unnecessary loss of design freedom, since current Power Park Modules would be capable of operating in a much wider range.

Furthermore, operation in off-nominal frequency could be a desirable design choice. On the other hand, if desired, frequency could be closely maintained to 50 [Hz] as it’s a controlled variable.

In the case of an AC hub, this design choice should be coordinated between all relevant stakeholders to ensure that it does not act as a blocking point for future extensions to hybrid projects or connection of equipment to it.

PROPOSAL TO CLOSE THE GAP:

Frequency ranges could be agreed on a project-specific way, but typical values for operation at 50 Hz could be suggested in the recommended practices for AC hub design or even a potential AC hub RfG. Operation at ±10% of nominal frequency range is possible for most full converter rated PPMs.

Recommendations on frequency ranges for operation in an AC hub should take into account the more flexible operating capabilities of PEIPS. The possibility of agreeing frequency operating ranges in a project-specific way should be allowed as it could enable non-conventional design solutions (off nominal operation).

(b) ARTICLE 13.2 – LFSM-O

GAP DIAGNOSIS:

The article proposes LFSM-O frequency threshold, droop ranges and performance characteristics (initial delay) in a context of Synchronous Area. Besides initial delay, the article does not request a minimum speed to reach the required reduction in active power.

PROPOSAL TO CLOSE THE GAP:

Proposed parameters could be adapted to better reflect the reality of an AC hub. It is believed that much shorter delays are possible and would be required in an AC hub. Furthermore, specific speed for reaching the required power reduction could be imposed taking into account the technological limitations of the equipment.

The guidelines could foresee a fast-power reduction mechanism via a fast-communication signal to reduce power. The application within an AC hub could require even faster performance than the ones defined in Article 39 of (European Commission, Network Code on HVDC Connections, 2016).

It should be clarified that the Frequency Sensitive Modes considered in Article 39 of [6] refer to frequency contribution **at the onshore connection point of the PPM**. Instead, this proposal focuses on **frequency support to improve stability of the offshore AC hub**. Therefore, since the PPM would have to support frequency at two different points, **conflicts could arise**. At first glance, the stability of the AC hub (as it is no more just generation) should be considered of top priority, but it falls upon the relevant operator (TSO or non-TSO) to define it.

Existing requirements in RfG could be insufficient (if translated directly) to ensure stability in the AC hub as dynamics are much faster than in a synchronous area. Fast power reduction mechanisms could be foreseen (e.g. as in Article 39 of (European Commission, Network Code on HVDC Connections, 2016))

(c) ARTICLE 13.4 – POWER REDUCTION DUE TO UNDERFREQUENCY

GAP DIAGNOSIS:

The article is mainly aimed at conventional units which due to technical reasons may have to decrease their power output in underfrequency situations. However, PPMs have a wider frequency range capability and do not necessarily face the same technical constraints. Therefore, unless there is indeed a valid technical reason for a PPM to decrease its power during underfrequency events, the requirement could be even stricter, in order to enhance the AC hub stability.

On the other hand, the article does not cover falling apparent power capability of PPMs with respect to the voltage at the connection point This is a typical characteristic of PPMs due to current limitations .

PROPOSAL TO CLOSE THE GAP:

As a best practice, PPMs could be able to operate at full nominal power in the whole range of connection frequency. This could ensure that PPMs connecting to AC hubs do not reduce output power unnecessarily with frequency reduction.

In addition, guidelines of maximum allowable apparent power reduction with falling voltage could be recommended, to harmonize the behaviour of PPMs under such conditions.

Existing requirements in RfG could be adapted to recommend that no power reduction (for PPM) occurs during underfrequency and that maximum allowable power reduction during undervoltage conditions is covered.

(d) ARTICLE 13.6 – CEASE ACTIVE POWER INJECTION

GAP DIAGNOSIS:

The requirement may be not applicable to AC hubs as the dynamics may be too slow.

PROPOSAL TO CLOSE THE GAP:

For the recommendation to be useful, best practices could request the cease of active power in a much shorter time frame, in the order of hundreds of milliseconds, as long as the technology allows such quick reduction.

The specific value for cease of active power injection could be agreed on a project specific basis, but it is expected to be much faster than 5 seconds, it is reasonable to think that on the range of tens to hundreds of milliseconds.

(e) ARTICLE 14.3 – DISTURBANCE RIDE THROUGH

GAP DIAGNOSIS:

The requirement is based on "remaining connected for a voltage-time profile". Nowadays, state-of-the-art PPMs will remain connected even during very severe faults, however the requirement does not specify the behaviour of the PPM while it is kept connected.

As an example, it would be acceptable to remain connected but block the PWM modulation of the power semiconductors. This is denoted as "momentary cessation" and refers to a fault ride-through strategy where the inverter remains connected but ceases the injection of active and reactive current. Momentary cessation has been reported to contribute to undesirable power system performance during faults (NERC, 2018), and has been identified as a challenge for integration of High Penetration of PEIPS.

Even though the above requirement has been partially captured in the fast-current injection requirements, the stability of the AC hub relies on PEIPS not only being able to remain connected, but also to perform correctly their system support functions during the fault.

Another important point is that the requirement does not define Over Voltage Ride Through profiles. However, this is a generalized remark and not specific to AC hubs.

PROPOSAL TO CLOSE THE GAP:

The gap could be covered by either explicitly stating the threshold at which momentary cessation is allowed or by extending the requirements on fast current injection. The key message remains that although the current guidelines ensure that devices remain connected, they do not describe what the devices should do while remaining connected to help grid stability during the fault.

It may be desirable to recommend the expected behaviour of the PEIPS in the case of faults, beyond the required connection times. Especially regarding when the converter is allowed to block and enter momentary cessation.

Over Voltage Ride Through characteristic could be recommended to assets connecting to the AC hub.

(f) ARTICLE 15.2 (C) AND (D)– LFSM-O AND FSM

GAP DIAGNOSIS:

The article proposes LFSM-O and FSM configuration ranges for parameters and performance characteristics (e.g. initial delay, full activation time) in a context of Synchronous Machine and Synchronous Area. Besides initial delay, the article does not request a minimum speed to reach the required reduction in active power.

Furthermore, depending on the grid-forming strategy, LFSM-O and FSM may not strictly apply for grid forming converters, but more for grid following ones. Also, the FSM response states a provision between 15 and 30 minutes, which is too long considering the characteristics of an AC hub and some technologies for energy storage in PEIPS (supercapacitor, hub inertia i.e. flywheel capacitors or synchronous condensers, – exception is long-term Battery Storage)

PROPOSAL TO CLOSE THE GAP:

Proposed parameters could be adapted to better reflect the reality of an AC hub. It is believed that much shorter delays are possible and would be required in an AC hub. Furthermore, specific speed for reaching the required power reduction could be imposed.

Fast Frequency Response and fast power injection triggered by communications could be included in the recommendations.

Existing RfG parameters could be insufficient to ensure stability in the AC hub as dynamics are much faster than in a synchronous area. Faster reactions such as very fast frequency response or communication-based responses could be foreseen.

12.8.3.3. Requirements for Power Park Modules

NC RfG Article No.	Article Topic	Challenges	Potential Gap
20.2 (b)	Requirements for type B PPM- Voltage Stability – Fast Current Injection	System Strength Forming the Voltage Disturbance Ride Through	Fast current injection speed and control performance and expected performance of grid forming behavior during faults could be further detailed.
20.3 (b)	Requirements for type B PPM- Robustness	System Strength Forming the Voltage	The expectations on how a grid forming converter behaves when it reaches the design limits could be further detailed to allow a predictable behavior during extreme faults.
21.2	Requirements for type C PPM – Synthetic Inertia	Forming the Voltage Inertia and RoCoF System Strength	Grid Forming capabilities could be explicitly requested by relevant operators, allowing them to specify control principles and expected performance.

Table 12-14: RfG Gap Analysis for AC Hub – Requirements for Power Park Modules – Summary Table

(a) ARTICLE 20.2 (B) – VOLTAGE STABILITY – FAST CURRENT INJECTION

GAP DIAGNOSIS:

Even though the article gives freedom to the TSO to specify "the timing and accuracy of the fast fault current…" It is possible that there is added value on specifying minimum expected performance on the fast current injection for support during faults that is to be performed by power park modules. Two key aspects of this minimum performance are the momentary cessation (that should not be allowed during the fault ride through) and the speed of the reaction.

As stated in (Weise, Korai, & Constantin, 2019), fast reaction from power converter during faults is key for system stability. Therefore, there could be some value in recommending a minimum level of performance.

Finally, it could also be of value to include and detail the behaviour of grid forming converters during AC faults, so they "keep forming the voltage" and therefore the AC hub grid does not experience an immediate collapse.

PROPOSAL TO CLOSE THE GAP:

The guidelines could detail the speed and minimum duration of the current injection, preventing that the PPM enters momentary cessation while having to inject current and include other recommendations. Performance requirements could be given according to power park module classes. For grid-forming converters, the literature suggests a reaction speed of a quarter of a cycle (Weise, Korai, & Constantin, 2019) (National Grid, 2020).

It could be valuable to specify the minimum performance for the PPM behaviour during faults that require fast current injection. Maximum time for reaction (e.g. 5 ms), management of current limitation and fault support time limits could be explicated, potential temporary overload capability (e.g. 20% over 500 ms) and maximum contribution time (e.g. 500 ms) could be defined.

(b) ARTICLE 20.3” (B) – ROBUSTNESS

GAP DIAGNOSIS:

Network codes do not cover the inherent current limitations of the inverters. Guidelines could be proposed in terms of how inverters need to manage current limitations, especially the ones with voltage forming duties.

PROPOSAL TO CLOSE THE GAP:

The guidelines could address the fact that voltage source converters behave as a Thevenin equivalent as long as their maximum ratings are not reached. Once this occurs, the limited behaviour of the converter will have important consequences to the power system stability, if not managed correctly.

PPMs participating in forming the voltage should manage their current limitation in a way the impact to the power system is limited, within the capabilities and rating of the specific asset. This could complement article 20.3.

(c) ARTICLE 21.2 (B) – SYNTHETIC INERTIA

GAP DIAGNOSIS:

As the Connection Network Code opens the possibility of TSO’s requesting synthetic inertia, a similar possibility could be considered for more advanced grid-supporting or grid-forming functionalities.

For example, the code could explicit ‘voltage source behaviour’, or ‘grid-forming’. On the same way, the article could allow the responsible party of the AC hub to define the operating principle and minimum performance parameters.

It could be thought that grid-forming capabilities could be requested from some assets during specific periods: One offshore HVDC terminal goes out for maintenance, grid forming functionality is requested (to be enabled) to the PPM, to keep the AC hub stable.

PROPOSAL TO CLOSE THE GAP:

PPM could participate in the voltage forming task during operation. The responsible party for AC hub operation could define the periods where this functionality is requested (normal operation, post-incident, asset in maintenance). Similarly, relevant aspects regarding the control principle and performance could be agreed.

The guidelines could open the door for PEIPS to develop widespread grid forming capabilities and request the use of these advanced functionalities. This could complement article 21.2.

12.8.4. Requirements of Demand connected to an AC hub

The Demand Connection Code (European Commission, Demand Connection Code, 2016) is dealing mainly with transmission-connected demand facilities, transmission-connected distribution facilities and distribution systems. Similarly to the other codes, it does not apply for systems operating non-synchronous to the Synchronous Areas. However, they serve as a starting point that allows to shed light on potential future requirements for an offshore AC hub.

In AC hubs, it is reasonable to assume that demand will have a more active participation in system balancing and stability. The aim of this section is to perform a gap analysis on the existing Network Connection Code – Demand Connection Code based on the actual requirements, and the specific challenges for the AC hub. This is shown in the schematic of Figure 12-20

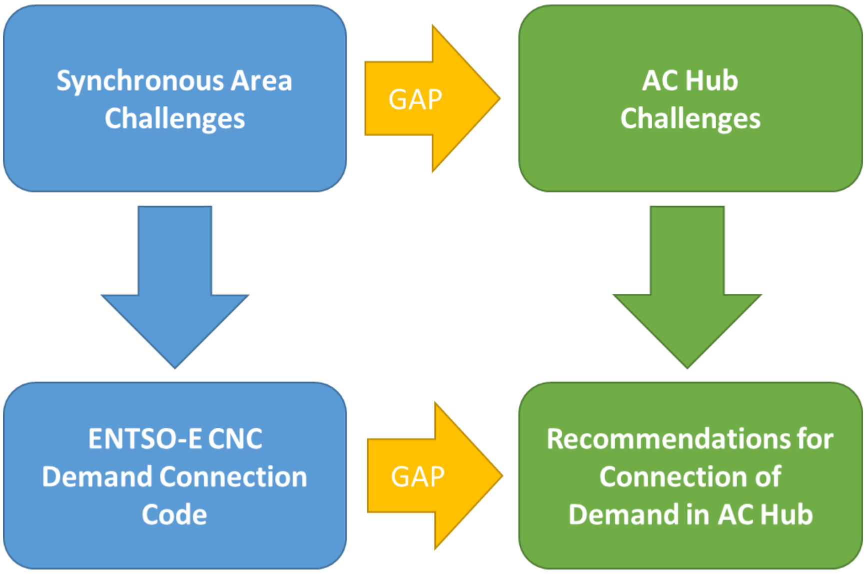


Figure 12-20: Gap Analysis on the ENTSO-E CNC RfG based on AC Hub Challenges

12.8.4.1. General Requirements

NC DCC Article No.	Article Topic	Challenges	Potential Gap
12.1 and 12.2	Frequency Ranges for Operation	Inertia and RoCoF	The recommendation needs to take into account the wider frequency capability of PPMs as well as off-nominal frequency operation.
13	General voltage requirements	Disturbance ride-through	Voltage ranges could be widened to accommodate the increased operating capabilities of converters.
14	Short-Circuit Requirements	System Strength	The article could be extended to address the challenge of system strength from the perspective of a demand facility.

16	Protection Requirements	Protection System Impact	Protection system should also cover new power system phenomena that rises due to power-electronics interactions.
19	Demand disconnection and demand reconnection	Power Balance Control during Contingency Conditions	Speed of the load disconnection systems should be improved to keep up with the dynamics of AC hubs.

Table 12-15: DCC Gap Analysis for loads connected to an AC Hub – General Requirements – Summary Table

(a) ARTICLE 12.1/12.2 – FREQUENCY RANGES

GAP DIAGNOSIS:

Classical loads may be only a small part of AC hubs. It is reasonable to expect that most loads connected to the AC hub will be power electronics interfaced loads that should allow for a wider range of operational frequencies. The gap is similar to the one on the Article 13.1 of the RfGs.

The DCC imposes very strict ranges based on the characteristics of Synchronous Areas units. Imposing these narrow operational ranges in an AC hub could result in unnecessary loss of design freedom. A minimum wider range could be useful but it may come at a cost (power-electronics interface). This cost could be small compared to the potential benefits that could arise from design and operation freedom.

PROPOSAL TO CLOSE THE GAP:

Frequency ranges could be agreed on a project-specific way. A wider range of typical values for operation close to 50 Hz could be suggested. This suggestion shall be coordinated with the same one affecting the connection of generating units.

Recommendations on frequency ranges for operation of loads an AC hub should take into account the more flexible operating capabilities of PEIPS. The possibility of agreeing frequency operating ranges in a project-specific way should be allowed as it could enable non-conventional design solutions, such as off nominal operation.

(b) ARTICLE 13 – GENERAL VOLTAGE RANGES

GAP DIAGNOSIS:

This article covers connection of systems from 110 kV. Below this, it is up to DSOs to define the minimum voltage range characteristics.

Wider voltage envelopes are expected from loads. as converters are capable to work within a wider voltage envelope. However, the impact on cost should be first investigated through cost-benefit analyses.

A load-specific LVRT profile could be useful if its desired to limit the disconnection of loads during faults. However, this is more relevant for the reliability of supply of the load rather than the stability of the AC hub, as the excess power could be rapidly curtailed/reduced.

PROPOSAL TO CLOSE THE GAP:

Voltage ranges could be agreed on a project-specific way. A wider range of typical values for operation could be suggested. This should be subject to additional studies to ensure that the increased voltage range does not result in increased cost (e.g. insulation or converter oversizing).

(c) ARTICLE 14 – SHORT-CIRCUIT REQUIREMENTS

GAP DIAGNOSIS:

Article covers maximum and minimum short-circuit levels at the connection point. Short-circuit current is one of the metrics used to measure system strength, but the article focuses on withstanding faults and short-circuit contribution of the demand.

The article could be extended to address the challenge of system strength from the perspective of a demand facility.

PROPOSAL TO CLOSE THE GAP:

The requirement could be extended to recommend acceptable levels of minimum system strength. However, this poses a challenge regarding measuring system strength, as fault current or even short-circuit ratio may not be fully suited for 100% converter system. It is recommended to invest efforts in clarifying the treatment of grid forming converters in system strength and how this interacts with the requirements of loads, as the classic metrics of Short-Circuit Ratio (SCR) or even newer ones of Effective Short Circuit Ratio (eSCR) (Miller, 2020) may not be directly applicable.

Short-circuit requirements from the perspective of withstanding faults remain similar in AC hubs. However how system strength is treated is totally different. New guidelines could be proposed in acceptable system strength values. However this requires research on identifying suitable system strength metrics that correctly capture the behaviour of grid-forming inverters.

(d) ARTICLE 16 – PROTECTION REQUIREMENTS

GAP DIAGNOSIS:

Article covers typical protection concerns used in power systems (over/under frequency and voltage). However, the protection system of loads connected to the AC hub could be extended to cover new phenomena that will arise in a high-penetration PEIPS system. It is reasonable to think that power-electronics connected load could play a role in system instabilities and therefore, suitable protection systems could be envisaged.

PROPOSAL TO CLOSE THE GAP:

For converter-interfaced loads, recommendations on new protection system that disconnect loads when a system instability is detected could be considered. Detecting and disconnecting the load is especially relevant when the load is participating in the system instability.

It is recommended to ensure that the protection systems of loads covers the scope of new type of instabilities driven by power electronics interfaces.

(e) ARTICLE 19 – DEMAND DISCONNECTION AND DEMAND RECONNECTION

GAP DIAGNOSIS:

Assuming that load disconnection will play an important role in the AC hub seems reasonable, as there will be less control resources than in conventional Synchronous Areas.

The article makes reference to classical UFLS/UVLS schemes that measure frequency and voltage in the terminals. In an AC hub, the actuation may not depend on frequency (as this could depend on the grid forming strategy) and could be initiated by a centralized control.

Ranges and parametrization of the functionality may be modified to better suit the specific AC hub dynamics. Operating times for remote triggering by a centralized control could be recommended.

PROPOSAL TO CLOSE THE GAP:

Requirements could be adapted to increase flexibility on how a load disconnection scheme could operate, for example, by allowing the triggering via centralized control.

Recommended times for actuation and frequency/voltage adjustability ranges could be agreed on a project-specific basis, allowing more flexibility than actual requirements.

Increase flexibility in the recommendation by allowing new kinds of actuation mechanisms and configuration parameters. Overall, speed of the load disconnection systems should be improved to keep up with the dynamics of AC hubs.

12.8.5. Requirements for Remote-end HVDC converter

This section covers the gap analysis for the requirements identified as most relevant for remote-end HVDC converters in AC hubs. The section highlights any points that might need to be harmonized or adjusted in case a remote-end HVDC converters is connected to an AC hub.

As indicated in Article 46 of the HVDC NC, the requirements 11 to 39 also apply to remote-end HVDC converter stations. In addition to the above, the HVDC NC defines Articles 47 to 50, which apply specifically on remote-end HVDC converters.

12.8.5.1. Active power control and frequency support

NC HVDC Article No.	Article Topic	Challenges	Potential Gap
11.1	Frequency ranges	Inertia and RoCoF	It is proposed to decouple the frequency range requirements of remote-end HVDC converters from the onshore ones. A wider frequency range as discussed in Section 12.8.3.2(a) could be considered.
13.3	Remedial control actions	Disturbance ride-through Power balance control during contingency conditions	Remedial actions taken at the remote-end HVDC converter station to ensure the stability of the AC hub might have to be considered.

15	Frequency Sensitive Modes	Inertia and RoCoF	Frequency support of the AC hub may become necessary.
17	Maximum loss of active power	Disturbance ride-through Power balance control during contingency conditions	Extension of this requirement to AC hubs should be considered.

Table 12-16 : Gap analysis for remote-end converters - Active power control and frequency support

(a) Article 11.1 – Frequency ranges

GAP DIAGNOSIS:

Frequency ranges covered in Article 11.1 are more suitable for conventional AC systems or offshore AC platforms where the frequency can be tightly controlled by one grid forming converter (i.e. one remote-end HVDC converter). In AC hubs, it will be necessary to coordinate several grid forming converters and the system might be subject to more frequent and larger frequency variations. Using the same requirements as for the synchronous AC systems can decrease the flexibility of operation of an AC hub.

Similarly, this gap has been detected for Generators and Demand connecting to the AC hub.

PROPOSAL TO CLOSE THE GAP:

It is proposed to decouple the frequency range requirements of remote-end HVDC converters from the onshore ones.

A wider range as discussed in Section 7.3.2.1 could be considered. However, further investigation is required in order to establish more specific requirements for an AC hub. In addition, a common set of requirements for remote-end HVDC converters could facilitate the extension to AC hubs.

(b) Article 13.3 – Remedial control actions

GAP DIAGNOSIS:

Potential remedial actions foreseen by a TSO would mainly aim at ensuring the stability and security of the onshore AC system. However, the security and stability of the AC hub can be of major importance, since its outage could have severe consequences for the HVDC systems connected to it and the adjacent AC areas. This importance is expected to increase as more equipment is connected to AC hubs, not to mention load and therefore specific reliability requirements.

PROPOSAL TO CLOSE THE GAP:

Remedial actions taken at the remote-end HVDC converter station to ensure the stability of the AC hub might have to be considered. These could include, for example, the ramp-up or ramp-down of power in the HVDC link following a pre-specified event in the AC hub.

Remedial actions to stabilize the AC hub should be considered and coordinated between the relevant TSO and/or non-TSO operators

(c) Article 15 – Frequency sensitive Modes

GAP DIAGNOSIS:

The proposed requirements and settings are well-suited for supporting the frequencies of Synchronous Areas. However, it is unclear whether frequency support is considered bi-directional in the HVDC NC, i.e. from the offshore system towards the AC system and vice-versa. Operating the remote-end HVDC converter in one of the frequency sensitive modes may be required to ensure correct operation of the AC hub, especially after a contingency. In addition, the specified setting, e.g. the requirement $s_1 \geq 0.1\%$ (which is inversely proportional to the permanent frequency deviation), might prove insufficient in an AC hub where a big power change has to be shared between fewer units. Instead, different ranges may need to be specified.

PROPOSAL TO CLOSE THE GAP:

The requirements on frequency sensitive modes for remote-end HVDC converters should be decoupled from the ones for onshore converters. Frequency support of the AC hub may become necessary. Nevertheless, this requires further investigation in order to establish specific requirements.

Frequency sensitive modes to support the AC hub frequency should be considered. This may require that the adjacent AC systems and interlinked HVDC systems transiently adjust their power to ensure the AC hub frequency stays within limits.

(d) Article 17 – Maximum loss of active power

GAP DIAGNOSIS:

The article concerns specifically the maximum loss of power injection in a synchronous area. The case of the AC hub is not discussed.

PROPOSAL TO CLOSE THE GAP:

The outage of one of the HVDC links connected to the AC hub could lead to loss of stability if, for example, the remaining HVDC links cannot evacuate the power produced in the AC hub.

Extension of this requirement for onshore AC systems to AC hubs should be considered.

12.8.5.2. Reactive power and voltage support

NC HVDC Article No.	Article Topic	Challenges	Potential Gap
48.1(a)	Reactive power and voltage requirements	Forming the voltage Providing system strength	Harmonization of voltage ranges offshore. Coordination between relevant operators and additional requirements on AC hub.

Table 12-17 : Gap analysis for remote-end converters – Reactive power and voltage support

(a) Article 48.1(a) – Reactive power and voltage requirements

GAP DIAGNOSIS:

This article defines the voltage ranges and time periods for which a remote-end HVDC should remain connected. The case of an AC hub was not in the scope of the current HVDC NC. The HVDC NC (European Commission, 2016) offers some flexibility for the minimum time period of operation for high voltages, as shown for example in Figure 12-21.

Currently, there is no established framework regarding the ownership and operation of an AC hub. However, it is expected that an AC hub will be an offshore connection point for several different PPMs connected to different TSOs or non-TSO operators. Coordination between them will be essential for its correct operation and having different sets of requirements would increase the complexity and pose operational challenges.

Reactive power and voltage requirements referred to in Article 48

Voltage range	Time period for operation
0,85 pu-0,90 pu	60 minutes
0,90 pu-1,10 pu	Unlimited
1,10 pu-1,12 pu	Unlimited, unless specified otherwise by the relevant system operator, in coordination with the relevant TSO.
1,12 pu-1,15 pu	To be specified by the relevant system operator, in coordination with the relevant TSO.

Figure 12-21: Minimal time periods for which a remote-end HVDC converter station shall be capable of operating for different voltages deviating from a reference 1 pu value without disconnecting from the network where the voltage base for pu values is from 110 kV to (not including) 300 kV

PROPOSAL TO CLOSE THE GAP:

It would be reasonable to harmonize these requirements among the various TSOs or other operators at the AC offshore point. Since the offshore AC hub is decoupled from the other AC systems, this is expected to have limited impact on the stability of the onshore AC system, while facilitating the future connection of the offshore point to an AC hub. Otherwise, the issue can most probably be resolved with increased coordination among the TSOs, which would lead to additional requirements on the AC hub. Wider voltage ranges could be considered subject to cost-benefit analyses.

Harmonization of voltage ranges at the offshore PoC should be considered. Coordination between relevant operators and additional requirements on AC hub will be critical.

12.8.5.1. *AC hub control and stability*

NC HVDC Article No.	Article Topic	Challenges	Potential Gap
N/A	Grid Forming Operation	Forming the voltage Providing system strength	Each remote-end converter should provide grid forming capabilities, if its technology allows it. If not, special control schemes should be put in place to support the rest of the grid forming equipment.
N/A	Coordination of remote-end converters in AC hub	Power balance control during contingency conditions Adverse system interactions Disturbance ride-through	A hierarchical control structure is needed to coordinate the remote-end converters. Its functionalities have to be defined and coordinated with the HVDC and onshore AC systems

Table 12-18 : Gap analysis for remote-end converters: AC hub control and stability

(a) Grid forming operation

GAP DIAGNOSIS:

The HVDC NC does not explicitly specify grid-forming requirements for the remote-end HVDC converter. To the authors' understanding this has the advantage that it does not exclude any converter technologies that might not be able to provide this capability. However, given the expected size of future AC hubs (in the order of several GW), grid forming capability will be crucial for the AC hub stability.

PROPOSAL TO CLOSE THE GAP:

Each remote-end HVDC converter connected to the AC hub should be able to operate in grid-forming mode, if requested, and if its technology allows this mode of operation.

If the converter technology does not allow such functionality, then it should provide other control functionalities in order to support the AC hub. These functionalities have already been included in the HVDC NC (articles 11 to 39 also apply on remote-end HVDC converters). However, it is unclear whether the settings defined for onshore HVDC control systems also apply offshore.

Each remote-end converter should provide grid forming capabilities, if its technology allows it. If not, special control schemes should be put in place to support the rest of the grid forming equipment.

(b) Coordination of remote-end converters in ac hub

GAP DIAGNOSIS:

In current point-to-point HVDC connections, the remote-end HVDC converter is the only grid-forming converter connected to the offshore platform. Instead, in case of an AC hub, it is expected that there will be more than one remote-end converters operating in grid forming mode, as shown in Figure 12-4. The coordination of several grid forming converters operating in parallel is not a trivial issue and has been the subject of research in the recent years.

PROPOSAL TO CLOSE THE GAP:

For the AC hub to operate correctly, a hierarchical control structure will most probably be needed to coordinate the remote-end HVDC converters. Each remote-end HVDC station should be able to receive commands and operating point changes from an AC hub controller. The task of the AC hub controller would be to coordinate the HVDC links connected to it. Its design is not in the scope of this work but a (non-exhaustive) list of functionalities is provided below:

Collection of frequency measurements from the onshore locations and adjustment of production of DC PPMs to provide the support where it is requested.

Adjustment of setpoints of remote-end HVDC converter to satisfy a desired power flow or power exchange between Synchronous Areas.

Supervision of the AC hub and correction of any violations after disturbances.

Setting up these functionalities will have to also consider constraints of the HVDC systems and of the onshore AC systems connected to the AC hub.

The Multi-DC project (Multi-DC project, n.d.) has investigated the need for such coordinating control schemes.

A hierarchical control structure is needed to coordinate the remote-end converters. Its functionalities have to be defined and coordinated with the HVDC and onshore AC systems

12.8.5.1. Information exchange and coordination

NC HVDC Article No.	Article Topic	Challenges	Potential Gap
51.1, 54.1 & 54.4	Interface and Simulation models	Simulation models Adverse system interactions	Extension of conclusions Section 12.6.8 to interlinked HVDC systems must be considered Real-time replicas should be considered to de-risk potential adverse interactions.

Table 12-19 : Gap analysis for remote-end converters – Information exchange and coordination

(a) Articles 51.1, 54.1 & 54.4: Interface and Simulation models

GAP DIAGNOSIS:

Coordination on the AC hub is critical for its reliable operation. The articles 51.1, 54.1 and 54.4, discussed in section 12.6.8, refer to exchange of information and coordination inside the same HVDC system. In the case of an AC hub, several HVDC converters from different HVDC systems will have to be coordinated.

PROPOSAL TO CLOSE THE GAP:

As a result, the conclusions of Section 12.6.8 are also extended to interlinked HVDC systems. Effort should be put into developing good simulation models and resolving potential Intellectual Property (IP) issues that can arise and complicate the operation of an AC hub. This becomes especially important when adverse interactions or other issues are observed and adjustment to the equipment (e.g. control retuning) has to be performed. In addition, the use of real-time replicas should be considered in order to limit the risk of inadvertent interactions when connecting a new HVDC converter to an AC hub.

Extension of conclusions Section 5.8 to interlinked HVDC systems must be considered.

Real-time replicas should be considered to decrease the risk of potential adverse interactions.

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