Grid-forming functional requirements for HVDC converter stations and DC-connected power park modules in multi-terminal multi-vendor HVDC systems

InterOPERA

Enabling multi-vendor HVDC grids

ABOUT INTEROPERA:

The InterOPERA project will define technical frameworks and standards for electricity transmission and accelerate the integration of renewable energy. Ensuring that HVDC systems, HVDC transmission systems or HVDC components from different suppliers can work together – making them "interoperable"- is a top priority to accelerate Europe's energy transition.

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Grid-forming functional requirements for HVDC converter stations and DC-connected power park modules (PPMs) in multi-terminal multi-vendor HVDC systems

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InterOPERA
Enabling multi-vendor HVDC grids

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Abbreviations and definitions

AC	Alternating current
BESS	Battery energy storage system
DC	Direct current
FRT	Fault ride-through
FSM	Frequency sensitive mode
GFL	Grid-following
GFM	Grid-forming
HIL	Hardware-in-the-loop
HVDC	High voltage direct current
MT	Multi-terminal
NC	Network code
PE	Power electronics
PEID	Power electronics interfaced device
POC	Point of connection
PPM	Power park module
RfG	Regulations for generators
RoCoF	Rate of change of frequency
SCR	Short circuit ratio
SSCI	Sub-synchronous control interaction
SSTI	Sub-synchronous torsional interaction
TSO	Transmission system operator
WTG	Wind turbine generator

The definitions in this report are based on the COMMISSION REGULATION (EU) 2016/1447 of 26 August 2016, establishing a network code on requirements for grid connection of high voltage direct current (HVDC) systems and direct current (DC)-connected power park modules (PPMs) (NC HVDC).

- '**Connection point**' means the AC interface at a synchronous area at which the power-generating module, demand facility, distribution system or HVDC system is connected to a transmission system, offshore network, distribution system, including closed distribution systems, or HVDC system, as identified in the connection agreement. The connection point is also typically referred to as the point of connection (POC).
- '**HVDC converter station**' means a part of an HVDC system which consists of one or more HVDC converter units (converting AC voltage to DC voltage or vice versa) which are installed in a single location together with buildings, reactors, filters, reactive power devices, control, monitoring, protective, measuring, and auxiliary equipment.
- '**HVDC system**' means an electrical power system which transfers energy in the form of high-voltage direct current between two or more alternating current (AC) buses and comprises at least two HVDC converter stations with DC transmission lines or cables between the HVDC converter stations.
- **'HVDC interface point'** means a point at which HVDC equipment is connected to an AC network, at which technical specifications affecting the performance of the equipment can be prescribed.
- '**DC-connected power park module'** means a power park module that is connected via one or more HVDC interface points to one or more HVDC systems.
- '**Relevant TSO'** means the TSO in whose control area a power-generating module, a demand facility, a distribution system or a HVDC system is or will be connected to the network at any voltage level.

- '**Synchronous area**' means 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.
- '**Island operation**' means the independent operation of a whole network or part of a network that is isolated after being disconnected from the interconnected system, having at least one power-generating module or HVDC system supplying power to this network and controlling the frequency and voltage.

In addition, the following definitions are used in the context of this report.

- '**Onshore HVDC converter station**' means an HVDC converter station which is synchronously connected to a synchronous area.
- '**Remote-end HVDC converter station'** means an HVDC converter station which is not synchronously connected to any synchronous area; in this task, it specifically means the HVDC converter station (typically located offshore) which the DC-connected PPMs are connected to, as shown in Figure 1 below.
- **'Isolated AC network'** means an AC network which is not part of a synchronous area, which is connected to a synchronous area via one or more HVDC systems.
- '**DC connection point**' means the interface at which the HVDC converter station is connected to the DC circuit in a HVDC system.
- **'GFM converter'** is used as a common terminology for either HVDC converter stations, remote-end HVDC converter stations or DC connected PPMs which are in GFM control mode and fulfill the GFM functional requirements as defined in the document.
- '**Operating limits**' means the voltage, current and energy limits (i.e., the submodules' voltage limits) that apply to converter units in HVDC systems and DC-connected PPMs.
- '**V/f control**' refers to the case where the HVDC converter station is the single component in an isolated AC network for generating, controlling and maintaining the AC voltage and frequency. In the context of DC-connected PPMs, this control mode is used mostly for offshore stations, where the wind turbines are in conventional GFL control (see definition of GFL control).
- '**Vdc control**' refers to the case where the HVDC converter is responsible for controlling and maintaining the DC voltage and ensuring that the desired DC voltage reference is reached in steady-state conditions (integral control). This is also sometimes referred to as direct voltage control, DVC.
- '**Vdc droop control**' refers to a purely proportional and fast change of DC voltage based on the changes in the active power exchange. The gain or droop of this controller can vary based on the DC voltage range in multi-terminal system.
- '**GFL control**' refers to the conventional grid-following or non-grid-forming control of a converter, where active (P) and reactive (Q) power exchange with the AC grid are controlled directly through controlling the active and reactive currents using current controllers. In GFL control, the converter acts as a controlled current source in parallel to an impedance and does not provide a notable inherent response to changes in the phase, frequency, and voltage amplitude. A support of AC grid during such disturbances in GFL mode is typically provided by changing the converter setpoints based on measurement values.
- '**Standalone operation**' refers to the operation scenario of an HVDC converter station or power-generating module, where the HVDC converter station or power-generating module is the only voltage source generating and controlling the AC voltage and frequency stably in acceptable ranges

for the AC grid. Standalone operation is differentiated from island operation by the number of voltage sources in the system, where in standalone operation the HVDC converter station or the power-generating module in question is the only voltage source while in island operation there could be multiple voltage sources in the system. Standalone operation can be triggered by the loss of the last voltage source in the rest of the AC grid. For example, for an onshore HVDC converter station in GFM control, it is the only voltage source in the onshore AC network supplying load together with GFL PPMs if any. The onshore HVDC converter station can get power supply from its DC-side. Another example is, for a remote-end HVDC converter station in GFM control or V/f control, it is the only voltage source in the offshore AC network transferring power from GFL PPMs to the DC circuit. The definition can also apply to a DC-connected PPM if it is in GFM control. In the case, it generates and controls the voltage and frequency in the offshore AC network and the connected remote-end HVDC converter station is in neither V/f nor GFM control. Besides, the PPM is considered as a whole and the only voltage source, although actual GFM controls are implemented at a number of wind turbines.

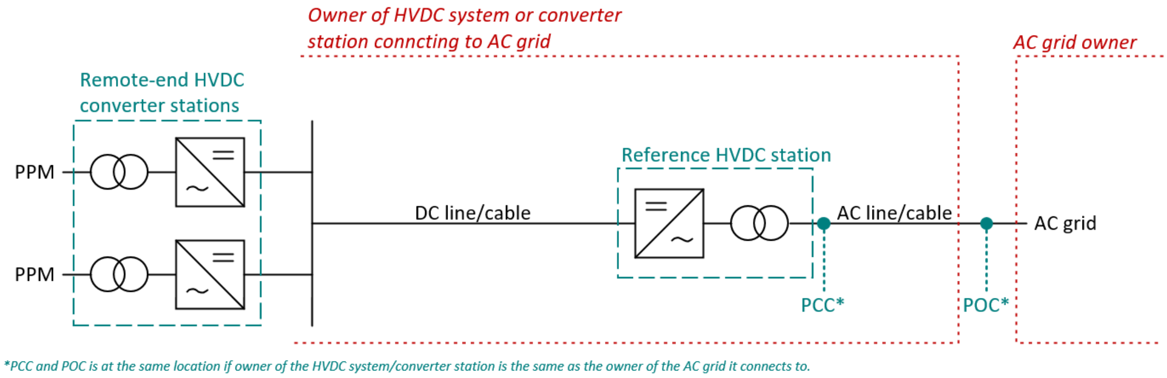

Figure 1. HVDC definitions as per NC HVDC.

Executive summary

By year 2050, 300 GW offshore wind power will be deployed in the EU to meet its climate target. One way of integrating such large amount of offshore wind power is via multi-terminal HVDC systems. The main objective of InterOPERA is to achieve mutual compatibility and interoperability by design among different subsystems from different vendors. Likewise, it is crucial that the multi-terminal HVDC systems assist in solving some of the challenges of the power electronic based power system as laid out by ENTSO-E [1].

Specifically, it is in Task 2.4 of InterOPERA (hereinafter referred to as 'T2.4' for brevity) that the topic of grid forming (GFM) capabilities to enable robust system integration is addressed. The main objectives of T2.4 are detailed in Objective 5 of the InterOPERA project, and involves:

- Specification of GFM functional requirements for onshore HVDC converter stations which can enable synthetic inertia support to the onshore AC system via the multi-terminal multi-vendor HVDC system.
- Specification of GFM functional requirements for DC-connected PPMs which can enable them to ride-through a temporary blocking of the remote-end HVDC converter station and hence increase the reliability of offshore wind power transmission.

This document is the deliverable from T2.4, named Deliverable 2.2 (hereinafter referred to as 'D2.2') as defined in the InterOPERA project. D2.2 contains GFM functional requirements which are formulated for three types of subsystems in the HVDC system:

- HVDC converter stations with an AC synchronous area connection point.
- DC-connected PPMs, e.g. PPMs connected to an isolated AC network.
- Remote-end HVDC converter stations operating in an isolated AC network.

D2.2 consists of three parts, corresponding to the three subtasks defined in T2.4 (hereinafter referred to as 'T2.4.1', 'T2.4.2', and 'T2.4.3', respectively). Part I summarizes the work from T2.4.1 and provides a literature review on the state-of-the-art of connection requirements for GFM control. This part consists of Chapter 1 and Appendix 1. Chapter 1 summarizes the main take-aways from the literature review, while Appendix 1 includes detailed summaries for each reference. Part II summarizes the work from T2.4.2, in which GFM functionality is defined and its application in a multi-vendor multi-terminal HVDC system for large-scale offshore wind power integration is discussed. This part consists of Chapter 2, 3, 4 and Appendix 2. Part III summarizes the work from T2.4.3, where in Chapter 5 the final GFM functional requirements are formulated for onshore and remote-end HVDC converter stations and DC-connected PPMs. In addition, corresponding recommendations to the European Network Code for HVDC are provided in Chapter 6 together with a comparison between the proposed GFM requirements within this document and the proposed GFM control article published by EG CROS in December 2023 [34].

The GFM functional requirements proposed in D2.2 could be applicable to many different power electronic devices. However, the multi-vendor multi-terminal HVDC system relevant aspect comes from:

- Establishing a common understanding of definitions and nomenclature with respect to GFM control across all stakeholders of the multi-vendor multi-terminal HVDC system.
- Creating a common understanding of how the behavior of GFM control dynamically couples the AC and DC connection points of the multi-terminal HVDC system.

- Establishing interdependencies between the DC and AC interface functionalities of the multi-terminal HVDC system.
- Ensuring that GFM control and DC voltage control is coordinated and that DC system security constraints are considered in the GFM control.

The main outcomes and conclusions from D2.2. are:

- Through the state-of-the-art review performed with publicly available literature early year 2023 it is found that the National Grid GBGF-I [7][8], the VDE FNN guidelines [3] and associated Cigré recommendation [4], OSMOSE project [9] and UNIFI specifications [10] are the most detailed and suitable for alignment of GFM functional requirements within the InterOPERA project.
- It is also found that none of the existing publicly available literature on the topic of GFM functional requirements addresses GFM functional requirements specifically for HVDC converters and DC connected PPMs in multi-terminal HVDC systems.
- The GFM functional requirements proposed in D2.2 are based on the voltage source behind an impedance definition, which is found to be the most prominent functional definition by the industry state-of-the-art.
- The GFM functionality of the voltage source behind an impedance is proposedly divided into 5 mandatory core functionalities, optional functionalities and withstand capabilities as shown in Table 1. These functionalities are further detailed in the document.
- It is proposed that the GFM converter shall fulfil the requirements if it is in normal operation, i.e., operating within its current, voltage and energy limits. If the GFM converter is in withstand operation, i.e., any of its current, voltage and energy limits are reached, the GFM converter shall preserve its GFM capability whenever possible, while maintaining stable operation and staying connected to the grid.

Table 1. Mandatory and optional GFM control functions and withstand capabilities as proposed in InterOPERA D.2.2.

Mandatory Functions	Optional Functions	Withstand Capabilities
Self-synchronization	Black start	Maximum step change of SCR at POC
Phase jump active power	Sink for voltage unbalances	Maximum phase jump
Inertial active power	Sink for harmonics	Maximum RoCoF
Positive damping power		Temporary islanding of PPMs
Inherent reactive power		

- The functional requirements for GFM control are defined equal for HVDC converter stations and DC connected PPMs, unless it is explicitly stated that the specific requirement only applies to one or the other. It is recommended that the dynamic performance requirements should be specified individually for each GFM converter type.
- For multi-terminal multi-vendor HVDC systems it is important to acknowledge that the HVDC converter primarily is an energy converting device, and that any transient active power associated with GFM control requires energy transfer in and out of the DC system and appropriate coordination with the DC voltage control scheme.
- It is proposed that all HVDC converter stations shall have GFM control functionality and Vdc droop control functionality and that it shall be possible to have these activated simultaneously.

- Under certain conditions, active power contribution (phase jump, inertial and positive damping active power) from the GFM controller to the AC grid can be limited, for example, due to DC voltage levels being outside acceptable limits. In such conditions, self-synchronization and inherent reactive power contribution may still be available. A set of minimum capabilities to be considered for GFM performance requirements is proposed for HVDC converter stations that have DC voltage control duty in an HVDC system.
- It is proposed that the GFM control of HVDC converters shall be limited by the DC voltage ranges and thresholds specified in the DC connection point of the HVDC converter.
    - GFM functionality shall be unlimited within the normal DC voltage range.
    - GFM functionality shall be gradually reduced when entering the alert DC voltage range.
- The Vdc droop control function and DC voltage ranges shall follow the requirements stipulated in D2.1 of InterOPERA [31]
- Remote-end HVDC converter stations can either be specified as classical V/f control converters or GFM converters. A remote-end HVDC converter that is specified as a GFM converter can be tuned to have very low inertial active power and will display very similar dynamic characteristics as a V/f converter.
- The capability of remote-end HVDC converters and DC connected PPMs to operate in parallel with other remote-end HVDC converters and DC connected PPMs is specified, and it is suggested that remote-end HVDC converters are specified as GFM converters instead of the classical V/f control as soon as it is required that they operate in parallel with other HVDC VSC converters.
- The functionality of a DC connected PPM to withstand a temporary islanding by self-synchronizing to ride-through a blocking of the remote-end HVDC converter station is specified in order to improve the overall operational robustness and availability of the power generation in the system.
- To relate the GFM functional requirements directly to multi-vendor multi-terminal HVDC systems, four use cases of applying GFM control are discussed in detail with different control operations assigned for different components as shown in Table 2 below. Use case 3 and 4 involves GFM control from the DC connected PPMs.

Table 2. Use cases of GFM control assignment in a multi-terminal multi-vendor HVDC system.

	Control modes assigned					
	Remote-end HVDC converter station		**HVDC converter station**		**DC-connected PPM**	
	AC/DC 1	AC/DC 2	AC/DC 3	AC/DC 4	PPM 1	PPM 2
1	V/f	V/f	GFM	V_{dc}	GFL	GFL
2	V/f	V/f	GFM-V_{dc} droop	GFM-V_{dc} droop	GFL	GFL
3	V_{dc} droop	V_{dc} droop	GFM	GFM	GFM	GFM
4	GFM-V_{dc} droop	GFM-V_{dc} droop	GFM-V_{dc} droop	GFM-V_{dc} droop	GFM	GFM

To sum up, by accomplishing the formulation of detailed functional requirements of GFM control for a multi-terminal multi-vendor HVDC system, the work in T2.4 and this report D2.2 contribute to advancing the realization of GFM control in real-life multi-terminal multi-vendor HVDC systems, which provides enhanced support to the stability of the onshore AC system and helps further integration of offshore wind energy.

Part I

Subtask 2.4.1

Literature review on available standards and grid connection code requirements on GFM control

1 Chapter 1: Literature review

Main take-aways from the literature review are listed in Section 1.2 in the chapter, while the detailed summaries for each reference are attached in Appendix 1: Literature review.

1.1 Introduction

InterOPERA is developing technical solutions to enable and demonstrate multi-terminal multi-vendor HVDC systems to support the green transition and electrification of the energy sector.

In order to integrate multi-terminal HVDC systems into the power system two key aspects must be addressed:

- How can a multi-terminal HVDC system be stabilized when connected to the power system, and further.
- How can the multi-terminal HVDC system help improve the stability of its neighboring components and the improve the overall power system strength?

To answer the above, the power system industry is widely looking into the application of the grid-forming control of power electronic devices which in general is considered as an enabler for the large-scale integration of power electronic devices in the power system.

Hence, as is defined in the Interoperability Workstream by ENTSO-E, T&D-Europe and WindEurope, developing functional requirements for grid-forming control which are applicable to multi-terminal multi-vendor HVDC systems is essential for a successful roll out of the technology.

As part of InterOPERA Task 2.4, named *Functional requirements for grid-forming control for multi-terminal multi-vendor HVDC systems and DC connected power park modules*, the InterOPERA consortium seeks to:

- Align the grid-forming definition between stakeholders, being TSOs, HVDC OEMs and wind power industry to secure multi-vendor interoperability.
- Align the overall goal, concepts and expectations to grid-forming functionalities in the context of multi-terminal multi-vendor HVDC systems for wind power integration.
- Formulate grid-forming functional requirements that are equally understood and accepted by all partners.

In order to achieve this goal, the InterOPERA consortium has formulated task 2.4.1 which involves a literature review of the latest industrial research and development of connection requirements for grid-forming control.

The intention of the literature review is to achieve the following:

- **Holistic industry view:** Secure alignment between the requirements to be developed in InterOPERA against existing or ongoing work in the industry.
- **Speed:** To make sure that the requirements are developed as efficiently as possible by building on what has already been built.
- **Multi-terminal specific details:** To search for gaps and details which may be different for multi-terminal HVDC systems compared to other applications of grid-forming control.

The InterOPERA consortium has decided to focus on literature which presents industrial work by system operators, system owners and OEMs to ensure that technology to fulfill the functional requirements is practically implementable while fulfilling the system needs. This means that novel ideas and concepts for grid-forming from academia are not prioritized.

The literature review presented in this document was produced by InterOPERA partners by:

- Gathering and prioritizing available literature on functional requirements
- Reading and active discussing of literature in groups with representation of HVDC OEMs, wind industry and TSOs
- Internal knowledge sharing, discussion and drafting of summaries.

1.2 Main take-aways

This section aims to summarize the main takeaways from the literature review.

1. As for the definition of grid-forming control, most literature use controlled voltage source behavior as the core in the definition, for example, "internal voltage source behind an impedance" (or "creating system voltage") [1][5][6][7][8] and "internal voltage phasor that is constant or nearly constant in the sub-transient to transient time frame" [10][25] or "slow-changing" [8]. The new EU Connection Network Codes is also expected to use this as a basis [2].
2. As for the expected capabilities of grid-forming control, some literature divides such capabilities into two groups, for example, mandatory and optional capabilities in [5], universal and additional performance requirements in [10]. Furthermore, these capabilities could be divided into groups based on operational conditions, for instance, non-disturbed and disturbed grid conditions in [2], normal and abnormal operational conditions in [10].
3. Some of the capabilities required for GFM converters in the literature can also be delivered by grid-following (GFL) converters, although these two types of converters have different controls and may differ in performance when delivering the services.
4. The difference between GFM and GFL control can be distinguished in their behavior following a grid disturbance in voltage magnitude, phase angle, frequency etc. Hence, the capabilities in such disturbed grid conditions formulated in the literature are the most inherent capabilities from GFM control. In non-disturbed conditions there are also critical capabilities from GFM control, for example, to create an AC voltage.
5. In disturbed grid conditions, certain capabilities from GFM control are further detailed at different timescales. For example, control objectives are focused differently on sub-transient timescales (roughly 0~5 cycles after a disturbance) and transient timescales (tens of cycles) [10]. In addition, the active power response following a disturbance is separated into different components (active phase jump power, active inertia power, active damping power etc.) in [7] to differentiate active power contributions based on characteristics from GFM control with different time constants.
6. An important thing to keep in mind is that converters may only achieve such GFM capabilities before reaching their current limits. Whether they can still be considered as operating in normal GFM mode after reaching current-limiting condition, and what the performance requirements should be in such a situation, need to be discussed further in detail. Thus, GFM capabilities in disturbed grid conditions need to be formulated in both before and after reaching current limits.

7. Post-disturbance period, which means the transitional period following a disturbance being cleared until getting back to normal operation, could also be considered as part of the disturbed grid conditions. Certain behavior in this period could also be required from GFM converters.
8. The following GFM capabilities are well aligned among the most literature:
    - Self-synchronization
    - Phase jump active power
    - Inertia response active power
    - Fast fault current injection / inherent reactive power response
9. However, different opinions are observed in different literature on the following capabilities:
    - Sinking of voltage unbalances
    - Harmonics cancellation
    - Fast frequency response
10. As mentioned above, some GFM capabilities described in the literature can also be provided by GFL control. Therefore, different capabilities may have different prioritization. For instance, it is stated that harmonics cancellation has a lower priority compared to those capabilities used during contingencies, which results in a lower priority in allocation of available headroom [1].
11. Most literature formulates the GFM capabilities respecting the hardware current limitations of the converters, giving no need for an oversized design to fulfill the requirements.
12. Black-start capability could be seen as a pure GFM capability that cannot be fulfilled by GFL converters, but in most literature, it is not included in the package of GFM capabilities. At most it is considered "optional" in some literature [5][10]. The reason is that black-start service may require additional hardware, design and functionalities that may incur extra cost and need special coordination with power system operators. It has also been decided that black-start capability is out of the scope for Task 2.4 in InterOPERA.
13. The UNIFI specifications [10] are intended to cover all GFM applications including but not limited to energy storage, solar PV, wind turbines, HVDC, STATCOM, UPS, fuel cells, or other yet to be invented technologies, but most other literature focus on battery systems [9].
14. It is worth noting that in any power electronic converter based GFM control, the coordination between the GFM control and the DC voltage control is critical for the stable operation of the system and fulfilling expected services at the same time [9][22].
15. Specifications on modeling and compliance testing are important parts of the GFM functional requirements to be formulated, since they help vendors understand the requirements and make it transparent on how to fulfill the requirements. Some literature gives introduction on this [1][3][8].
16. Most literature only provides high-level qualitative instead of quantitative specifications on GFM capabilities. Some quantitative specifications are provided in [7][8], but they can be too restrictive to some extent, as the requirements should only specify the AC side performance instead of detailed control schemes implemented in converters [10][25]. Task 2.4 in InterOPERA strives to formulate exhaustive specifications, which means quantitative in some cases, for GFM functional requirements in a multi-terminal HVDC system, but meanwhile retain the freedom for vendors to design their own GFM control schemes.
17. In general, active participants involved in Task 2.4 think the GFM specifications developed by National Grid ESO [7][8] are most detailed and worth aligning towards, while some others have also been found useful, in particular the FNN guidelines [3], OSMOSE project [9] and UNIFI specifications [10].

18. As mentioned in the introduction, none of the existing literature on the topic has mentioned GFM in multi-terminal HVDC connections and the deliverable of InterOPERA Task 2.4 would be the very first document on this topic.

Part II

Subtask 2.4.2

Definition of grid-forming control concepts and control hierarchy for MT HVDC applications

2 Chapter 2: Definition of GFM functionality for HVDC converters and DC-connected PPMs

Part II describes the conceptual application of grid forming control (GFM control) in multi-vendor HVDC systems with multi-terminal topology defined as part of Task 2.4.2 of InterOPERA. Firstly, GFM functionalities are defined in accordance with the state-of-the art outlined in Part I Task 2.4.1. Secondly, the impacts of GFM control in HVDC systems are described and discussed, and lastly various control mode configurations and scenarios for GFM in HVDC systems are described. The statements and descriptions in Part II, being Chapter 2,3 and 4, is not requirement wording, but intended to provide background information, examples and explanations leading to the functional requirements in Part III Chapter 5 and Chapter 6. The intention of any example provided in Part II is never to imply preference or requirement for a specific solution, but simply to discuss and elaborate with the purpose of creating a mutual understanding.

2.1 System needs: Why is GFM control required?

The ENTSO-E technical report *High Penetration of Power Electronic Interfaced Power Sources and the Potential Contribution of Grid Forming Converters (HPoPEIPS)* [1], outlines the challenges of the power electronics (PE) dominated power system associated with high penetration of converter-interfaced power park modules (PPMs) and HVDC systems. Moreover, from this report it is shown that GFM technical requirements are linked to future system needs as a means to ensure power system stability. Therefore, a separate analysis and discussion on the system need for GFM converters is not repeated here. The ENTSO-E report outlines several challenges being ranked by their expected severity as listed and quoted below [1]:

1. Decrease of total system inertia in a synchronous area;
2. Resonances due to power electronics and cables;
3. Reduction of transient stability margins;
4. Missing or wrong participation of PE-connected generators and loads in frequency containment;
5. Loss of devices in the context of fault-ride-through (FRT) capability;
6. Lack of adequate reactive power support;
7. Introduction of new power oscillations and/or reduced damping of existing power oscillations;
8. Excess of reactive power;
9. Voltage dip-induced frequency dip;
10. Altered static and dynamic dependence of loads;

The ENTSO-E report then defines a new class of PPMs and HVDC systems, which has the seven quoted functionalities below [1]:

1. Creating system voltage
2. Contributing to fault level (within the first cycle following a fault)
3. Contributing to total system inertia (limited by energy storage capacity)

4. Supports system survival to allow effective operation of low frequency demand disconnection (the effectiveness of LFDD reduces when the frequency changes are faster and larger)
5. Controls act to prevent adverse control interactions (control interactions between converter controllers may occur in weak grid conditions)
6. Acts as a sink to counter harmonics & inter-harmonics in system voltage
7. Acts as a sink to counter unbalance in system voltage

As part of InterOPERA and the interoperability work stream it is essential to develop GFM functional requirements for HVDC systems and DC-connected PPMs such that they can contribute positively to solve the challenges outlined by ENTSO-E and comply with the capabilities listed above.

2.2 Gap in the literature: Coordination of GFM control between converters in an HVDC system

In Task 2.4.1, a literature review was carried out on the state-of-the-art of functional requirements for GFM converters. A summary report was delivered and is presented in Part I of this document.

The report summarizes the latest technical requirements for GFM converters formulated by different organizations worldwide. Some literature [2] specifies requirements on HVDC converter stations, but only a single converter station is discussed, without mentioning the remote-end HVDC converter station, seeing the effect of such requirements at system level and discussing where or how the active power required for the GFM functionality should come from. Most literature up to date focuses on single converters instead of large interconnected systems. No literature addresses multi-vendor HVDC systems.

The main goal of Task 2.4 is to specify functional requirements to GFM at the connection points of the HVDC system to the AC synchronous area in order to support the system integration and overall system strength. Thus, GFM functionalities are primarily targeting the interface of the HVDC system to the AC synchronous area, with a focus on their impact on the operation of the whole HVDC system. However, as GFM control involves fast energy transferring in and out of the HVDC system, the associated impact on the dynamic active power balance must be coordinated across the entirety of the multi-terminal HVDC system. Thus, the GFM functional requirements should involve references to the DC connection point, where thresholds must be maintained as specified in order to not compromise the DC system security.

Consequently, in order to secure the full control chain required for GFM in multi-terminal multi-vendor HVDC systems, and enable GFM support from the DC connected PPMs, the GFM functionality must be specified at all interfaces between the relevant subsystems in the multi-terminal HVDC system. Thus, in Task 2.4 of InterOPERA, GFM functional requirements are not only specified at the AC synchronous area connection point, but also at the isolated offshore AC connection point, where the DC connected PPM and the remote-end HVDC station are coupled.

Hence, with respect to GFM functional requirements for multi-terminal multi-vendor HVDC systems for large-scale renewable energy integration, the gap is in functional requirements for:

- HVDC converters (typically onshore) in the connection point (AC) as well as DC connection point.
- Remote-end HVDC converters (typically offshore) at the HVDC interface point as well as the DC connection point.
- DC connected PPMs in the HVDC interface point.

2.3 Multi-vendor interoperability aspect of GFM control

As to be described in further detail in Chapter 3, GFM control involves a fast dynamic coupling between the AC connection point and DC circuit of the HVDC system, where energy is exchanged and transients in DC voltage and AC active power may occur across the HVDC system.

Depending on the requirements and parameters selected, the GFM control may involve less or more energy exchanged between the AC network and DC circuit of the HVDC system.

For a single-vendor multi-terminal HVDC project, in which the whole HVDC system in the project is provided by the same vendor, the boundary of responsibility lies at the connection point between the HVDC system owner and the relevant system operator of the onshore AC grid. In such case, the relevant TSO only specifies the GFM functional requirements at the connection point for the HVDC system, while the DC grid and interdependencies between the AC power and the DC side control could be considered an internal problem where everything is coordinated and solved by that single-vendor.

However, for a multi-vendor project, in which different converter stations in the HVDC system are provided by different vendors, there will be responsibility boundaries not only at the connection point, but also at the DC side in the HVDC system (defined as "DC connection point" in the report).

Thus, GFM control of multi-terminal multi-vendor HVDC systems needs an alignment of functional requirements, detailed specifications with parameter settings and a coordination of AC and DC voltage control and protection schemes, careful control tuning across all HVDC converter stations and DC-connected PPMs as a coordinated response is needed.

Consequently, the *multi-vendor multi-terminal* specific aspect of the GFM functional requirements presented in this document involves:

- Establishing a common understanding of definitions and nomenclature with respect to GFM control across all stakeholders of the multi-vendor multi-terminal HVDC system, also including the DC connected PPMs.
- Creating a common understanding of how the behavior of GFM control dynamically couples the AC and DC interfaces of the multi-terminal HVDC system.
- Establishing interdependencies between the DC side and AC side functionalities of the multi-terminal HVDC system.
- Ensuring that DC system security constraints are considered in GFM control.

In the following sections, the GFM functionality is defined and discussed for multi-terminal HVDC systems in general, without addressing detailed requirements at different connection points (AC or DC) in a multi-vendor set-up, which will be discussed and delivered in Chapter 5.

2.4 Common understanding: Voltage source behavior

Based on the state-of-the-art development and the ongoing discussions on the amendment of the European connection network codes (NC RfG and NC HVDC) that provides the legal basis for all functional and detailed specifications of HVDC system and vendors entering in the European energy market, an effort of agreeing on a definition of GFM functionality is made in the context of InterOPERA, as part of the work of defining functional requirements. It should be mentioned that this effort is made with a focus on reaching a common understanding of such functionality among the project partners.

The agreed proposal is to define the GFM functionality as the inherent behavior of an HVDC system or DC-connected PPM to act as a controlled voltage source behind an impedance, following the definition of the ENTSO-E technical group work HPoPEIPS [1]. The voltage source behavior at the connection point of a HVDC converter station or DC-connected PPM shall be maintained as long as the HVDC system or the PPM is within the operating limits. This voltage-source behavior means that the HVDC converter station and/or the PPM shall maintain its internal voltage phasor nearly constant in the first cycles following a disturbance, while slowly changing its internal values to adapt to the post-disturbance conditions. During this timeframe and as long as the voltage and current limits of the HVDC system and DC-connected PPM are not reached, the HVDC converter station and/or the PPM shall resist changes in the grid voltage magnitude and phase angle by an exchange of immediate power, which has mainly an active component during phase angle changes and mainly a reactive component during changes in the voltage magnitude.

The functionality of a controlled voltage source behind an impedance shall apply under normal operating conditions and immediately after a grid disturbance. If operating limits of the HVDC converter station are exceeded, or the HVDC converter station is disturbed causing the HVDC system or DC-connected PPMs to move outside the normal operating range, the HVDC system or DC-connected PPM is allowed to change its voltage source characteristics and limit the GFM functionality in order to protect the converter and avoid tripping. This is referred to as the withstand operation of the converter in terms of GFM functionality. The normal operation and withstand operation are further detailed below.

2.4.1 Inherent functionality and immediate response

In the voltage source behind an impedance definition above, the GFM control is described as an *inherent* control capability with an *immediate* power response. This terminology is used throughout this report and the functional requirements presented in Chapter 5 and Chapter 6. Within this document, inherent GFM functionality means that the functionality does not rely on external controllers or measurements, and that the power output is delivered immediately due to voltage phase angle changes or voltage magnitude as per relationship in Equation 1 and shown in Figure 2. Some literature prefer to use the terminology *natural* instead of inherent, but the intention and meaning is the same. Immediately means that the response must be near-instantaneous, but with a reasonable tolerance for control delay. Some references such as the GBGF-I quantifies a tolerance of 5 ms when assessing the performance [7], but this limit has not been adopted in the requirement text in this document due to its difficulty in evaluation.

$$P = \frac{E_s V_g}{Z} \sin\theta \quad \text{where} \quad \theta = \theta_s - \theta_g \qquad \textit{Equation 1}$$

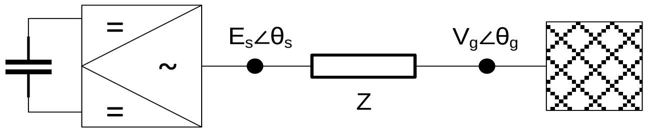

Figure 2. Power electronic converter as a voltage source behind an impedance Z.

2.4.2 Normal operation

Normal operation is defined as the period where the HVDC system or DC-connected PPM is within its operating limits. This includes the time-dependent voltage and frequency limits specified in the NC HVDC [26]. Within its operating limits, the HVDC system or DC-connected PPM may be exposed to disturbances to voltage magnitude, angle, or frequency at its connection point to which it must react as a slow-changing voltage source behind an impedance. GFM functionality discussed in the report mainly applies when the HVDC system or DC-connected PPM is in this mode of operation.

2.4.3 Withstand operation

Withstand operation is defined as the operation of the HVDC converter station or DC-connected PPM when any of its operating limits is reached. In withstand operation the GFM converter shall preserve its GFM capability whenever possible, while maintaining stable operation and staying connected to the grid. The GFM converter is not required to act as slow-changing voltage source behind an impedance when in withstand operation. The GFM converter is only allowed to disconnect from the grid if the time-dependent voltage and frequency limits specified in the NC HVDC are exceeded [26].

2.4.4 Transition between normal and withstand operation

The HVDC converter station or DC-connected PPM may adapt its voltage-source characteristics when changing from normal operation to withstand operation. The transition between normal operation and withstand operation shall be as seamless and continuous as possible[1] considering the characteristics and severity of the event disturbing the converter into withstand operation.

2.5 Grid-forming functionality

NC HVDC is the European regulation that establishes the legal basis for defining technical requirements that HVDC systems and DC-connected PPMs shall fulfill, in order to enter the European energy market. Hence, the GFM functional requirements shall be seen as an additional set of requirements on top of the already existing connection requirements that are defined in the NC HVDC. That said, in defining the functional requirement for GFM HVDC system and DC-connected PPM, one should not duplicate already existing requirements but rather add functionality exclusive to GFM.

[1] It has been discussed within InterOPERA T2.4 to explicitly state that no change in control mode from GFM to GFL is allowed when transitioning to withstand operation. However, it is argued by OEMs that this is over-specification which goes beyond describing a functionality. Instead it is prefered to focus on specifying the required performance and behaviour when transitioning from normal to withstand operation.

As described in Section 2.4, GFM behavior is understood as the behavior of an HVDC system or DC-connected PPM as a voltage source behind an impedance. However, with the aim to further detail GFM functional requirements and more importantly to make it quantifiable and measurable, the state-of-the-art literature largely agrees to sub-divide the voltage source behavior down to different distinguishable functionalities in response to different types of grid disturbances, which can be measured quantitatively on a timescale. In InterOPERA this detailing of the voltage-source behavior is adapted in order to derive the functional requirements for GFM control, which is needed for InterOPERA Objective 5: *Develop grid-forming control features, in support of onshore AC system*.

The literature largely agrees to the definitions of GFM functionalities derived from the voltage-source definition, but minor deviations in the terminology used and disagreements exist. The agreements and disagreements are listed in the Task 2.4.1 work in Part I.

In InterOPERA it is decided to propose five sub-divided mandatory functions which together encompass the voltage-source behind an impedance behavior. Besides these, there are three optional functions and withstand capabilities included as well for the GFM functionality. The functions are shown in Table 3 and elaborated in the following sections.

Note that the functionality to act as a sink for voltage unbalances and sink for harmonics has been purposely defined as optional functions in InterOPERA, although they are listed in the ENTSO-E report [1] as important functions of the new class of power electronics. The reason is that sinking voltage unbalances and harmonics have been deemed as not unique to GFM control alone and hence out of scope of demonstrating GFM control by multi-terminal multi-vendor systems in InterOPERA.

Table 3. GFM functionality at the connection point of HVDC systems.

	MANDATORY FUNCTIONS	OPTIONAL* FUNCTIONS	WITHSTAND CAPABILITIES
1	Self-synchronization	Black start	Maximum step change of SCR at POC[2]
2	Phase jump active power	Sink for voltage unbalances	Maximum phase jump
3	Inertial active power	Sink for harmonics[3]	Maximum RoCoF
4	Inherent reactive power		Temporary islanding of PPMs
5	Positive damping power		

*=GFM converter may have additional capability to support the black start process; GFM converter may have dedicated control loops to act as a sink for harmonics and unbalance in system voltage.

In the following sections, detailed elaboration is provided for the GFM functions listed in Table 3. The GFM functions are only expected from the HVDC system or DC-connected PPM when it is in normal mode, i.e., the operating limits are not reached. For simplicity, this assumption is not repeated in the following sections.

[2] It is acknowledged that classical SCR is a poor system strength indicator in power electronic based power systems, and it could be considered to formulate this requirement more broadly as *system strength step change* to allow for other methods and indicators to be applied.

[3] Although an important capability for power electronics in the power system as described in [1] the capability of GFM converters to act as a sink for harmonics is not described or specified further within the document as it is deemed as not being uniquely related to GFM control.

The methodology for measuring and calculating active and reactive power related to compliance testing of the core GFM functions as described in Section 2.5.1 to Section 2.5.5, shall be coordinated by the relevant system operator and the HVDC OEM(s) and owners of DC-connected PPMs. Applicable standards such as the IEC 61400-21-1 should be considered.

2.5.1 Self-synchronization

Self-synchronization is the capability of a GFM converter to be capable of generating and controlling an open circuit three phase AC voltage of a given frequency and voltage magnitude and synchronizing with the rest of the AC grid independently from other generation sources.

Self-synchronization does not refer to the operation of closing an AC breaker between two live buses, for example, in the process of connecting a live GFM converter to a live AC bus from open to closed circuit.

Self-synchronization capability enables an HVDC converter station with GFM functionality to be capable of standalone operation, where the electrical island can either be a small power system with a few buses and units, or a larger portion of a synchronous area. With a sufficient DC source available, the HVDC converter station in standalone operation shall be able to supply its own ancillary load and other connected loads, together with other grid-following (GFL) PPMs if any. An example is provided in Section 9.1 in the appendix to illustrate the behavior of a GFM converter getting into standalone operation and the difference from a simple GFL converter facing the loss of the last voltage source in the rest of the AC grid.

Self-synchronization capability enables an HVDC converter station with GFM functionality to be able to synchronize and operate stably with other power-generating modules in the grid when it is not subject to large disturbances[4]. These modules include both conventional synchronous generators and PPMs (either GFM or GFL).

Self-synchronization capability alone does not qualify the converter as a GFM converter, and a GFL converter could by enhancement be designed to have this functionality as well. Thus, for the converter to be fully qualified as a GFM converter it must additionally have the capabilities described in the following sections.

2.5.2 Phase jump active power

An HVDC system or DC-connected PPM with GFM functionality shall be capable of maintaining its internal voltage phase angle nearly constant at its pre-disturbance level (can slowly change) for a given time duration (in ms) when exposed to phase angle jumps at the connection point, as long as their operating limits are not violated. This will lead to an inherent active power response of the converter to the phase angle jump, where its peak magnitude depends mainly on the phase jump angle and the impedance between the internal voltage source and the grid voltage at the connection point.

The output of the phase jump active power is an inherent capability of the GFM converter to respond immediately to changes in the phase angle of the grid voltage.

[4] It needs to be further investigated whether there is a risk of loss of synchronization of the GFM converter to the rest of the AC grid when the converter is at certain operating setpoints and under certain extremely severe grid conditions, like low SCR, even without being subject to large disturbances.

Example:

Considering a GFM converter connected to an external grid as previously shown in Figure 2 in Section 2.4.1. The impedance Z encompasses the converter impedance, including physical, virtual and/or equivalent control impedances, filter impedance and any impedance from transformers between the converter and the connection point.

Equation 1 from Section 2.4.1. show the classical power angle equation which expresses that the active power output is proportional to the voltage angle difference between internal voltage source angle θ_s, and the grid voltage angle θ_g. A negative jump in the grid voltage angle θ_g, will lead to an increase in the power angle θ as long as the internal source angle θ_s remains nearly constant for a predefined time period, and thus lead to an increase in active power output, which is referred to here as phase jump active power. Similarly, an instant positive jump in grid voltage phase angle θ_g will lead to a transient reduction of the power angle θ and thus negative phase jump power. Figure 3 illustrates the GFM transient response to negative and positive phase jumps, leading to positive and negative phase jump active powers. As shown in Figure 3, the phase jump active power returns to the pre-disturbance value according to the dynamics of the GFM control.

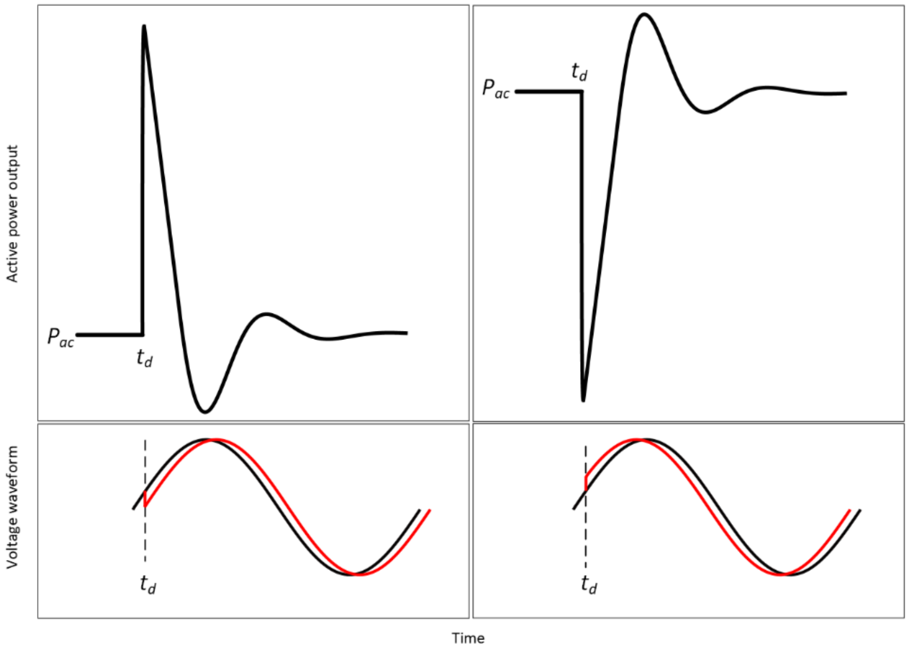

Figure 3. GFM phase jump active power response to negative (left) and positive (right) phase jumps in grid voltage ϑ_g (In the voltage waveforms, the red curve is the grid voltage while the black one is the internal voltage of the GFM unit).

2.5.3 Inertial active power

The injection or absorption of inertial active power is an inherent capability of a GFM converter to respond inherently to changes in the grid frequency without any reliance on frequency estimation. The amount of power is proportional to the RoCoF.

An HVDC converter station or DC-connected PPM with GFM functionality shall be capable of injecting or absorbing inertial active power to or from the AC network following the changes in frequency.

The injection or absorption of inertial active power in response to a frequency ramp typically requires more energy transmitted through the HVDC converter in comparison to a phase jump, due to the larger duration of the active power support.

The maximum amount of energy in MWs that is injected or withdrawn from the HVDC system at its connection point shall be defined by the relevant system operator, and in agreement with the HVDC OEM, using rated RoCoF withstand capability as defined in Art.12 of NC HVDC and Art. 13 of NC RfG in case of the DC connected PPMs.

2.5.4 Inherent reactive power

A GFM converter shall be capable of inherently injecting or absorbing reactive power to or from the AC network, when there is a change in the difference of the magnitudes between the grid voltage at POC and the internal voltage of the GFM converter.

The injection or absorption of inherent reactive power is an inherent capability of a GFM unit to respond immediately to changes in the magnitude of grid voltage.

The GFM converter shall comply with the inherent reactive power response as long as the converter is within the normal voltage and frequency operating range as specified in network codes, as well as within its own hardware limitations.

Some literature from the state-of-the-art review in Section 1.2 distinguish and differentiate inherent reactive power capability from fast fault current injection of GFM converters. However, from InterOPERA T2.4 it is proposed to consider these as equal capabilities and combine them under the inherent reactive power definition, as both relate to the immediate current injection to a change of voltage magnitude in the connection point. The problem of current limitation and transient stability during faults is addressed by the withstand operation requirements in Section 2.4.3.

2.5.5 Positive damping power

The GFM converter shall be able to provide positive damping to system oscillations in the sub-synchronous range [27].

In general, the damping capability of GFM converters can roughly be divided into two different categories:

1. The inherent[5] *electromechanical* power swing damping and its equivalent damping coefficient D
2. The capability to damp various electrical resonances, torsional interactions, or controller interactions.

The capabilities listed under Item 2 are not unique to GFM control and may equally be delivered by GFL converters as well as GFM converters and may involve external controllers and measurements.

Considering a synchronous generator (SG) as an analogy to understand the difference of Item 1 and Item 2, the SG has damper windings, which provide an inherent positive damping power, and at the same time the synchronous generator may or may not have a power system stabilizer (PSS), which is a dedicated control function which is specifically tuned to damp a certain oscillatory phenomenon.

[5] Inherent implies that the functionality is achieved without reliance on external measurement or higher level control loops

Both Item 1 and Item 2 may lead to positive damping of oscillations in the sub-synchronous range, but the inherent power swing damping capability is mainly associated with the damping of electromechanical dynamics. For a classical SG the PSS is also used to damp electromechanical modes, but it can be designed and tuned more freely than the inherent damping which is a physical property. For a GFM converter any strictly inherent damping capability is highly dependent on the GFM control implementation and other design dependencies. Hence, by requiring a high positive damping strictly in the form of *inherent* GFM damping functionality, one may dictate the control implementation in a way that may or may not be beneficial to the overall functionality of the GFM converter and the actual system needs.

Thus, in InterOPERA T2.4 it is proposed to not specify whether the positive damping shall be inherent in the GFM control structure or not, but instead propose that the owner or relevant TSO focus on specifying the dynamic performance requirements to suit the system specific needs for damping.

The necessary active power response of the positive damping functionality and the resonances which are damped depends on the project specific tuning of the controls and shall be coordinated with the relevant system operator. This function can only be achieved if it is not contradicting other grid supporting functions which may be required.

The impedance response of the GFM converter or other industry accepted methods can be used to quantify its participation on the damping of sub-synchronous oscillations [11].

3 Chapter 3: Application of GFM functionality in multi-terminal multi-vendor HVDC systems

This section describes the influence of applying GFM control to multi-terminal multi-vendor HVDC systems with DC-connected PPMs, focusing on the following exchanges in and out of the DC circuit caused by GFM actions:

1) Phase jump active power.
2) Inertial active power.

Positive damping power in response to sub-synchronous oscillations is equally an important GFM function. However, its quantification and demonstration require detailed frequency domain analysis, and for this reason it has been left out of the conceptual description. However, it is emphasized that the provision of positive damping capability is considered a mandatory grid-forming requirement in InterOPERA.

The other non-grid forming functionalities identified in the literature survey of Task 2.4.1 are equally important for the integration of HVDC systems but are deemed as not being multi-terminal HVDC specific, and not specific for the multi-vendor demonstration in InterOPERA.

3.1 GFM control impact on DC voltage

Several of the state-of-the-art sources, such as the OSMOSE project [9], describe the application of GFM control for battery energy storage systems (BESS) where energy is exchanged quickly between the AC system and a BESS. The advantage of the GFM BESS is that the energy source or sink required for GFM functionalities such as phase jump active power and inertial active power is integrated together with the converter that is interfacing the AC grid.

A misconception that may occur is that significant GFM functionality can be delivered by charging and discharging of capacitance within converters and cables with the state-of-the-art technology today. However, the energy stored within the submodules of the standard HVDC converter station and the DC cable alone is too limited to provide significant phase jump active power or inertial active power while maintaining the DC voltage within an acceptable range if there is no other energy source. Consequently, the immediate energy for grid-forming functions of a HVDC converter station must be delivered by one or several other active power sources connected to the same HVDC system. These sources could be another AC synchronous area, DC-connected PPMs or other devices considering future scenarios and applications.

Robust control and stability of the DC voltage is essential for system security and multi-vendor interoperability in multi-terminal HVDC system. The power flows in continuous operation are controlled by coordinated DC voltage control where set points are calculated and provided by a centralized DC grid controller. This typically involves DC voltage droop control (which can be piecewise linear functions), and protective devices such as dynamic braking systems (DBS) with DC choppers which will react to over-voltages under large disturbances.

When the converter stations of an HVDC system are designed with GFM capabilities at the connection point and delivers phase jump active power and inertial active power, the necessary energy is extracted from or injected to the DC side of the HVDC converter station.

Figure 4 shows a point-to-point HVDC-VSC converter with GFM control at the converter station connected to Network 1. The HVDC converter station connected at Network 2 is in grid-following Vdc control. Figure 5 shows the converter response to a positive and a negative 30° phase jump at t = 5 s. The converter is operated at 50 % power rating prior to the phase jump.

In the case of the negative phase jump, the transient phase jump active power peaks close to 100 % power rating, but without exceeding the limit, while the DC voltage drops to 0.92 p.u. due to the energy extraction from the DC link. The magnitude of the phase jump depends on the impedance of the AC network.

In case of the positive phase jump, the transient phase jump power reduces the active power output close to 0 % power rating, while the DC voltage rises above 1.08 p.u. due to energy being injected into the DC link.

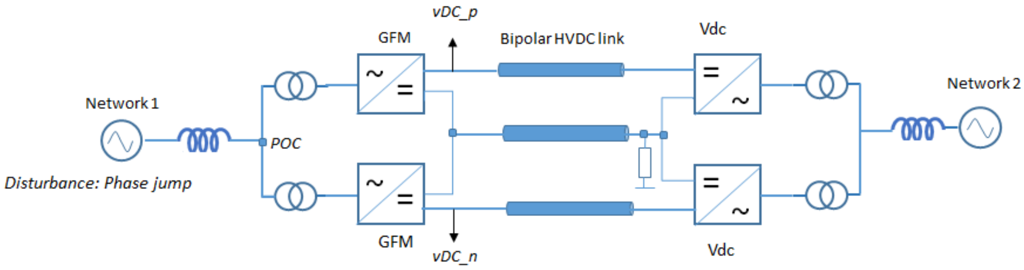

Figure 4 Point-to-point HVDC system with GFM functionality at the connection point in the Network 1.

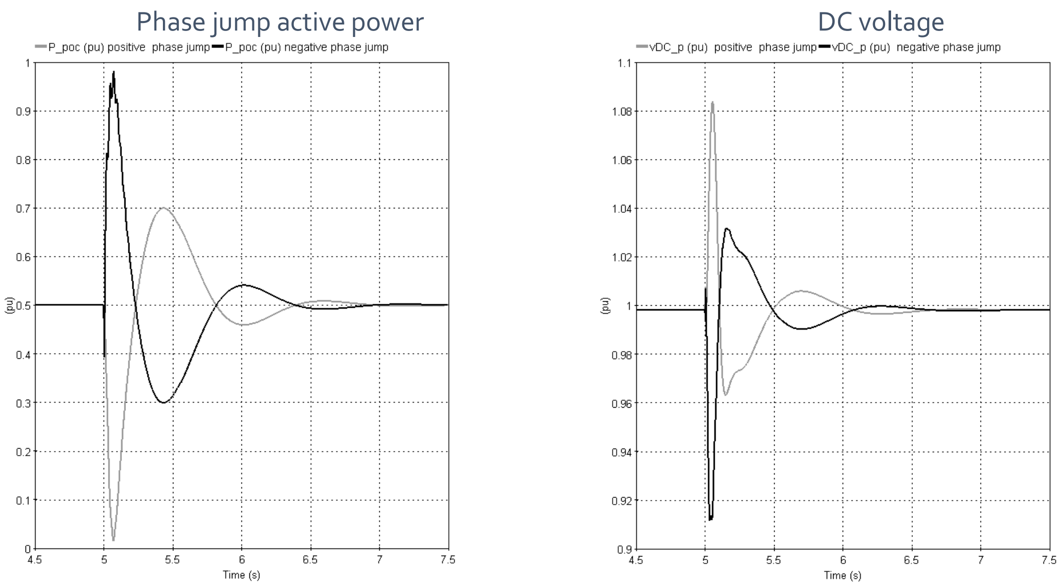

Figure 5. GFM HVDC-VSC response to positive and negative phase jumps.

Simulation conditions:

- Initial active power at POC: 0.5 pu (2GW base power)
- DC voltage: ±525 kV
- SCR=2.5 at POC (GFM side)
- Disturbance: phase jump: +/- 30° at t=5s

Energy is injected to or absorbed from the DC system to fulfill the GFM functionality on the AC side, which brings disturbances to the DC voltage. Since the DC grid voltage needs to be maintained within certain operational limits, grid-forming services shall be carefully coordinated with the applied DC voltage control concept.

Additional simulations are provided in Appendix 1 showing how GFM functionality responding to changes in frequency and AC voltage magnitude impacts the DC voltage.

3.2 Coordination of GFM and DC voltage control

One option for converter station control modes and their designation in a multi-terminal HVDC system without GFM functionality for large-scale offshore wind power integration would be as shown in Figure 6. Here the remote-end (offshore) HVDC converters are in fixed V/f control mode, the DC-connected PPMs are in GFL control mode and the onshore HVDC converters are in V_{dc} droop control mode. This is a robust active power control chain, as active power imbalances occurring due to variations in wind power generation get transferred and distributed to the two onshore areas purely by local controls and without communication between subsystems.

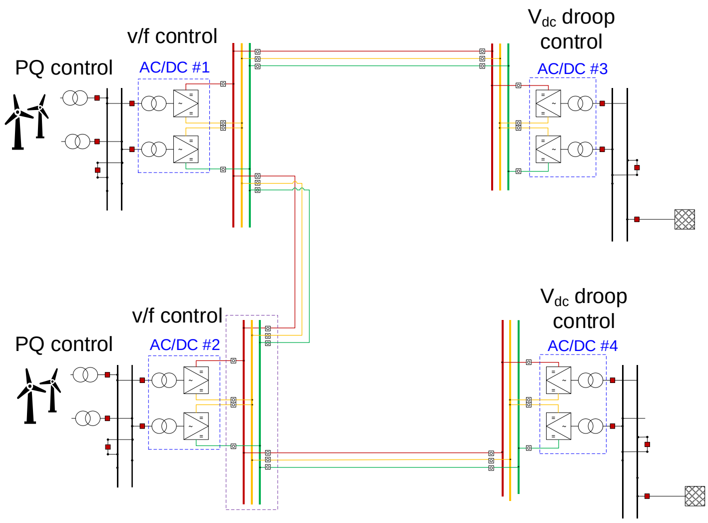

Figure 6. Four terminal HVDC system for wind power integration with offshore V/f control and onshore Vdc droop control.

The fixed AC voltage and frequency control at the remote end HVDC stations transfers any power imbalances to the DC grid, this results in an increase or decrease is DC voltage, and the onshore V_{dc} droop control transfers the power to/from the onshore AC grid. Thus, when desiring to apply GFM control in multi-terminal HVDC grids for wind power integration it is important to consider how the GFM functionalities interacts with the power balancing controls and how the balance can be maintained for the purpose of robustness.

This implies that the onshore HVDC converters shall have a control mode, which enables V_{dc} droop control and GFM control functionality simultaneously, but with respect to the energy balance constraints described in Section 3.1.

However, for the purpose of InterOPERA Task 2.4 the objective is to formulate functional requirements and not specify solutions, and as such any discussion of control implementation is only to provide examples and explanation.

3.2.1 The GFM and Vdc droop control functionality

If requested by the relevant TSO, HVDC converter stations that are part of a multi-terminal multi-vendor HVDC system, are expected to be able to contribute to the continuous DC voltage control for energy balancing. The requirements for continuous DC voltage control are specified in Deliverable D2.1 of InterOPERA [31].

The functional requirement proposed in InterOPERA T2.4 is that HVDC stations in multi-terminal HVDC grids shall have a:

1) GFM control mode which enables the mandatory functionalities listed in Table 3, and a
2) Vdc droop control mode which fulfills the requirements stipulated in InterOPERA D2.1 [31]

The GFM and Vdc droop control functionality shall be capable of being activated on the HVDC converter station simultaneously. This simultaneous GFM and Vdc droop control is referred to as GFM-Vdc droop control functionality in this document, where the name emphasizes the requirement of simultaneous operation without implying any method of implementation. It is important to note, that simultaneous does not imply the contradicting control of AC power and DC voltage at the same time instant but is referring to the capability to provide a GFM functionality while satisfying a constraining DC voltage controlling capability for robust multi-terminal DC grid control.

For remote-end HVDC converters the GFM-Vdc droop functionality also implies compliance with all the requirements that are standard to v/f controlling HVDC converter stations for offshore wind power integration.

3.2.2 Limitations of simultaneous GFM and Vdc control

As introduced in Section 3.1 GFM functionalities which involve fast energy exchange in and out of the HVDC converter will lead to transient disturbances of the DC voltage at the DC connection point of the HVDC converter station. It is mainly the phase jump active power, inertial active power and positive damping power functionalities that are expected to impact the DC voltage significantly. The magnitude and dynamic characteristics of the DC voltage disturbance, depends on the dynamic performance required of the GFM control by the relevant TSO, the strength of the AC network and the amount and properties of DC controlling converters in the DC grid.

If a HVDC converter is not configured for any type of DC voltage control contribution, it may be designed for high phase jump active power, high inertial active power and high positive damping, assuming that other subsystems in the HVDC system is designed to control the DC voltage sufficiently.

On the other hand, if a HVDC converter station is designated to contribute to DC voltage control, there are consequential constraints imposed on the possible dynamic performance of the GFM control functionalities.

In order to coordinate GFM control and DC voltage control capabilities there are two main considerations to unfold:

1) Respecting DC voltage operational boundaries
2) The impact of dynamic performance requirements and converter tuning

3.2.3 Respecting DC voltage operational boundaries

As described in Deliverable D2.1 [31] the DC voltage at the DC connection points in the multi-terminal HVDC system must be kept within specified ranges to ensure control and stability of the DC system. Figure 7 defines three ranges of DC voltage for DC voltage droop control. The range between U_{dc1} and U_{dc2} is the normal operation range, the range between U_{dc1} and U_{dc4} is the lower alert state and the range between U_{dc2} and U_{dc3} is the upper alert state. Below U_{dc4} and above U_{dc3} is the emergency state[6].

An important aspect of GFM control of HVDC converter stations in multi-terminal HVDC systems is, that the energy transfer in and out of the converter due to GFM control shall be constrained to maintain the integrity of the DC voltage by respecting the DC voltage operational ranges: Normal, alert and emergency.

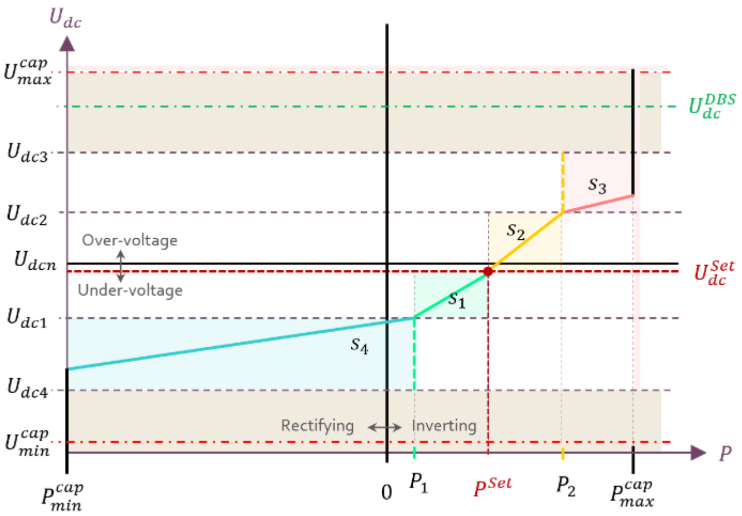

Figure 7. DC voltage states and thresholds for continuous control as defined in InterOPERA D2.1 [31]. The range between U_{dc1} and U_{dc2} is the normal operation range. The range between U_{dc1} and U_{dc4} is the lower alert state. The range between U_{dc2} and U_{dc3} is the upper alert state. Below U_{dc4} and above U_{dc3} is the emergency state.

Similar to AC current limitation during withstand operation the GFM control of HVDC converter stations shall have a DC voltage limiting function which can constrain the GFM functionality within a specified DC voltage range.

Table 4 show DC voltage ranges and the required limitation of phase jump power, inertial active power and positive damping power depending on the DC voltage measured. In the normal DC voltage range the active power available for GFM control shall be unlimited by the DC voltage.

[6] Task 2.1 and the continuous control subtask is still ongoing at the time of finalizing Task 2.4 grid-forming functional requirements, and the DC connection point requirements may change. However, the GFM constraints defined at the DC connection point shall follow the final definitions of D2.1, which may overrule what is stated within D2.2.

In the alert DC voltage range the active power available for GFM control should be limited proportionally to the DC voltage deviation from the normal DC voltage range. In the emergency DC voltage range the active power available for GFM control shall be limited to zero.

Table 4. HVDC station GFM control active power response limiting according to DC voltage operation

		GFM control active power response		
State	Range	Phase jump active power	Inertial active power	Positive damping power
Normal DC voltage	$U_{dc1} < U < U_{dc2}$	Unlimited	Unlimited	Unlimited
Alert DC voltage	$U_{dc4} < U < U_{dc1}$ or $U_{dc3} > U > U_{dc2}$	Proportionally reduced	Proportionally reduced	Proportionally reduced
Emergency DC voltage	$U < U_{dc4}$ or $U > U_{dc3}$	Zero	Zero	Zero

Figure 8 is an illustration of how the power available for the GFM functionality could be limited according to the measured DC voltage. In the left example of Figure 8 the limit on active power is linear from 100 % to 0 % in the range from U_{dc2} to U_{dc3}. However, the properties of the V_{dc}/P_{GFM} characteristic could also shaped with different gradients as illustrated in the right example of Figure 8. The characteristic could also be asymmetrical for over- and under DC voltage. It is the responsibility of the relevant TSO to specify the characteristics of the DC voltage limiting function of the GFM control in coordination with the HVDC OEM. In practice the proportional or linear limitation of the GFM control as a function of the DC voltage as it is exemplified in Figure 8 is challenging to achieve. This is due to the required inherent response of the GFM control, which implies that there is very limited time to react and control the active power response according to the DC voltage deviation. Consequently, the requirement for proportionality cannot be guaranteed in every case and a considerable tolerance should be accepted as the main priority is to maintain DC voltage stability.

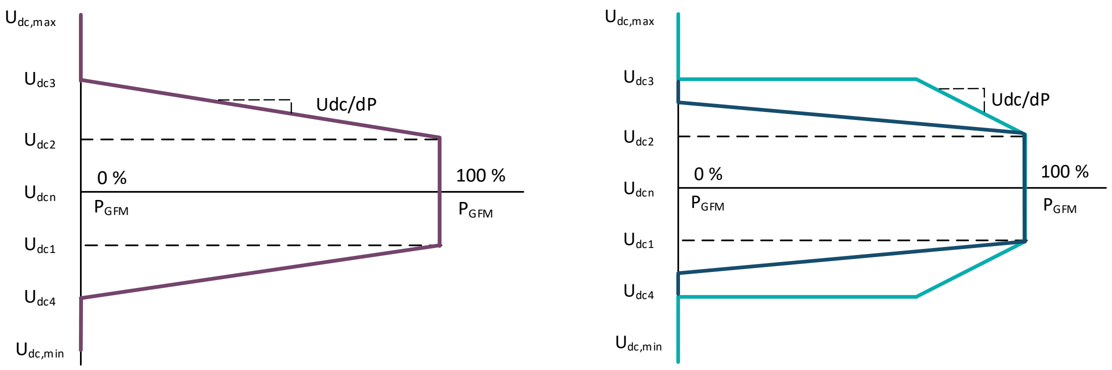

Figure 8. Concept of GFM active power response limiting due to DC voltage constraints

Another consideration is to allow the GFM control to disturb the DC voltage to the limits of the alert range, U_{dc3} and U_{dc4}, unconstrained for a short time duration. This implies that the DC voltage limiting function of the GFM control should have a time duration dependency, t_{dclim}, which enables that the DC voltage can be disturbed transiently into the alert range due to GFM control action, without any limitation due to DC voltage if the DC voltage recovers within t_{dclim}. However, whether this functionality is feasible considering its impact on the overall performance of the HVDC system is not evident at this novel stage of formulating DC connection point requirements for the GFM control of HVDC converter stations.

3.2.4 Impact of dynamic performance requirements and converter tuning

The dynamic performance requirements imposed on the GFM control of the HVDC converter by the relevant TSO or project developer, and the consequential design and tuning by the HVDC OEM, will directly impact the DC voltage control and stability of the DC grid.

If the GFM converter is designed for high active phase jump power or high inertial active power, the dynamic characteristics of the disturbance imposed on the DC voltage in the DC connection point of converter is different compared to the converter is designed for low active phase jump power or low inertial active power. High phase jump power design will lead to larger transient DC voltage jumps in positive or negative direction, and similarly will a high inertial active power design lead to more energy being transferred to or from the DC grid when the converter is exposed to frequency changes, which impacts the DC voltage in the DC connection point of the converter.

If the DC grid has several other DC voltage controlling nodes, which are capable of swiftly balancing the energy being transferred in and out of the DC grid due to GFM control, the DC voltage may not be disturbed close to the alert or emergency range when significant phase jump power or inertial active power action is taking place. On the other hand, if there is limited DC voltage controlling capability across the DC grid, even low phase jump active power or inertial active power responses may lead to reaching the DC voltage limits discussed in Section 3.2.3.

Thus, it can be generally stated, that the disturbance imposed on the DC voltage due to GFM control at any HVDC station in the DC grid, depends on

1) The tuning of the GFM control itself,
2) the strength of the AC network which the GFM converter is connected to, and
3) the dynamic capability of all other DC sources in the DC grid to supply or extract the energy imbalance seen as a DC voltage deviation.

One important aspect is that there will be both physical time constants in the DC voltage change across the DC grid depending on lengths and capacitance of the DC lines, and time constants and delays in DC voltage measurement and DC voltage control response at all the DC connection points in the DC grid.

The phase jump power response is a fast transient event with a steep AC power gradient, whereas the inertial active power is slower, depending on the RoCoF in the connection point of the GFM converter. Thus, the DC voltage dynamics across the DC grid will be different for the two GFM control events.

Table 5 is an attempt at roughly outlining which capability of phase jump power and inertial active power can be expected depending the extend a given HVDC station in GFM control mode has to contribute to V_{dc} control and the DC controlling capability of other DC sources in the system.

The key message is, that if a GFM HVDC converter station has to contribute to V_{dc} droop control in a HVDC system with *weak* or few other DC controlling sources, the dynamic performance requirements for active power associated GFM functionalities must be adjusted accordingly. If the HVDC converter station would be required to deliver high phase jump power or inertial active power in such a DC grid, the DC voltage risk being pushed to the alert and emergency limits frequently in operation, which may compromise the integrity of the DC system. Additionally, the desired GFM performance would likely not be achieved, as the response would become limited due to the DC voltage constraints as described in Table 4.

Consequently, the coordination between GFM control and DC voltage control would be poorly designed, as frequent large disturbances would be imposed on the DC system without achieving the desired GFM performance.

Table 5. Expected GFM functionality of a HVDC station depending on the Vdc control duty and other DC controlling sources in the DC grid.

		HVDC station GFM control active power functionality	
V_{dc} control duty of the HVDC station	DC control capability of other DC sources in the system *	Phase jump power capability	Inertial active power capability
None	High	High	High
None	Low	Medium	Low
V_{dc} droop	High	Medium / High	Medium / High
V_{dc} droop	Low	Low	Very limited
V_{dc}	-	Very limited **	Very limited

* Refers to the DC control capability of the HVDC system combined. This is a combination of the amount of DC control contributing stations in the HVDC system, the dynamic performance characteristics of the DC voltage control of those stations and the operating point of the HVDC stations.

** The GFM capability of the HVDC converter station being in V_{dc} control mode is expected to be very limited. Any inherent AC current response due to phase jumps will likely be limited to just keeping the stability of the converter in weak grid operation.

3.2.5 Minimum GFM capability for HVDC converters with Vdc droop control duty

As introduced in Section 3.2.4 it is not recommended to impose the same dynamic performance requirements for GFM control on HVDC stations with V_{dc} control duty as HVDC stations that does not have V_{dc} control duty.

As discussed, the achievable performance is likely to be very system and project dependent, where the GFM capabilities of one HVDC station in the multi-terminal multi-vendor HVDC system depends on the DC controlling capability of the system combined.

In general, it can be said, that the main objective of GFM control of a HVDC converter station with Vdc droop control duty is to improve the converters capability to integrate into weak AC networks without compromising the control and stability of the DC grid. Thus, the HVDC converter station with DC voltage control duty's capability to improve the system strength for other devices in the AC network may be limited depending on the characteristics of the DC grid behind it and the capabilities of other subsystems in the DC grid.

Table 6 lists the mandatory GFM functions for HVDC converters in general, and the minimum capability which should be considered when formulating performance requirements for HVDC converters with V_{dc} droop control duty.

Table 6. Minimum GFM capability of HVDC converters with Vdc droop control duty

Mandatory GFM Functions	Minimum capability of GFM converters with V_{dc} control duty
Self-synchronization	Full capability required. Shall be able to survive disconnection of last other voltage source unit in the system as per standalone definition
Phase jump active power	Low capability. Phase jump power mainly for self-stabilization and not improving overall system strength. Evaluated in low SCR connection.
Inertial active power	Low / zero capability. Relevant TSO specifies equivalent inertia constant H derived from RoCoF test. Could be close to zero equivalent H.
Positive damping power	Capability depends on type of oscillatory phenomena. Limited to damping of resonances that does not require significant active power response from the GFM control.
Inherent reactive power	Capability required

3.2.6 Re-tuning of GFM control capability after commissioning

During the lifetime of the HVDC converter station or PPM the overall system characteristics and system needs are likely to change. This could either be changes within the multi-terminal multi-vendor system, where the DC controlling capabilities are significantly increased or decreased, or at the AC interfaces of the HVDC system where system parameters such as inertia levels may be changing in an unanticipated way. For this reason, TSOs consider it beneficial to be able to take the GFM converter out of service and update the main parameters relevant for the GFM control performance if needed. This would be implemented by the HVDC OEM or PPM owner upon request from the system operator. However, the GFM control parameters cannot be updated without considering the full converter design and other possible scenarios, as the change may impact multiple critical design parameters and scenarios that are not uniquely related to GFM control. As such, a full design verification is needed, and the compliance studies must be reassessed with the new set of parameters.

Thus, within InterOPERA Task 2.4 the feasibility of stipulating a requirement to be able to update the GFM control parameters after commissioning has been discussed. The conclusion is that currently there is no consensus between TSOs and OEMs whether this requirement is reasonable or not, and as a consequence it has been decided to not include it in the general requirements introduced in Chapter 5 and Chapter 6.

A project specific solution may be, that the relevant TSO requests two sets of GFM control parameters upfront from the project beginning, such that OEMs can take it into account during the project design and execution phases and studies all the way to commissioning, knowing that it will lead to a significant scope increase in design, testing and studies.

3.3 V/f control of remote-end HVDC converter stations

Today point-to-point HVDC VSC technology is a mature solution for connecting offshore wind power to the transmission grid over long distances. Here the state-of-the-art solution is that the offshore HVDC converter, also referred to as remote-end HVDC converter, generates the AC voltage waveform to which the DC connected PPM synchronizes. This control mode is typically referred to as voltage-frequency control, or V/f control, and the converter controls are designed to keep the AC voltage and frequency constant within the design limitations of the converter. This functionality of the remote-end HVDC converter corresponds to the self-synchronizing capability of GFM converters defined in Section 2.5.1. However, there is a misalignment in the industry whether the classical V/f control of remote-end HVDC should be categorized as GFM control or not. The remote-end V/f control typically doesn't involve any electromechanical dynamics associated with the implementation of power-based synchronization and the swing-equation from the initial definitions of GFM control, as this is unnecessary or even undesired for the operation of a purely power electronic based offshore grid for wind power integration. Thus, as such the V/f control typically doesn't align with the full grid-forming definition as outlined in the state-of-the-art reviewed in Chapter 1 and described in Section 2.5. On the other hand, the V/f control is *forming* the AC voltage and frequency of the offshore grid, as without it there would not be a system voltage for components to synchronize to. Thus, a difference in perception and opinion appears.

There is a recent suggestion [28] to define the remote-end V/f control as "Grid-leading" control and differentiate this from GFM control by the difference in source characteristics and application as shown in Table 7. Another proposal which has been discussed within InterOPERA is to divide GFM control into synchronous GFM control and asynchronous GFM control, where V/f control would fit into the asynchronous GFM control definition.

Table 7. Literature [28] suggested distinction between GFM control and remote-end V/f control, named grid-leading control.

	Grid-leading control	Grid-forming control
Type of source	Fixed voltage source	Controlled voltage source behind an impedance
Application	Islanded grids with single-voltage source	Interconnected and islanded systems with multiple sources

However, to avoid misunderstanding and introduction of novel definitions, it is decided within InterOPERA to keep with the naming convention of *V/f control* to describe the behavior of HVDC VSC converters operating an isolated AC grid but without all 5 combined GFM functionalities listed in this document. For example, the V/f control converter may fulfill the self-synchronization requirements, but not inertial active power.

Table 8 roughly compares the functionality of V/f control remote-end HVDC converters and GFM remote-end HVDC converters. The message is that the functionality of a V/f control converter is very similar to a GFM control converter that is designed with very limited active inertial power or phase jump power, and where the main purpose of the converter is to generate a voltage and frequency for the isolated AC system and transmit the power generated.

Thus, the proposal is that a remote-end HVDC station can either be specified as a v/f control converter or a GFM converter, and this choice is made by the relevant TSO or system developer from the project beginning.

The GFM converter shall fulfill the same basic functionalities as v/f control converters as per NC HVDC, but with the additional GFM functionalities proposed within this document. If there are any conflicts in requirements between the existing version of the NC HVDC and the GFM requirements proposed, the relevant TSO shall state the priority. As the NC HVDC is amended and updated to include GFM control and multi-terminal HVDC systems [34], it is expected that the potential conflicts in existing requirements and new will be resolved as the requirements and solutions mature.

The remote-end HVDC station specified as a GFM converter may have better ability to operate in parallel with other voltage source converters in the isolated AC system, and as outlined in Section 3.4 if a V/f converter has P/f and Q/v droops for parallel operation, it may as well be specified as GFM converter rather than a V/f control converter.

Table 8. Distinction between v/f control remote end HVDC converters and GFM control remote end HVDC converters.

v/f control remote-end HVDC	Grid-forming control of remote-end HVDC
Fulfills the requirements for frequency control as per NC HVDC Article 47 Fulfills the requirements for voltage control as per NC HVDC Article 22. Has similar functionality as the Self-synchronization capability specified for GFM converters. May operate in parallel with other v/f converters or GFM converters if P/f and Q/v droops are added (see discussion in Section 3.4)	Is able to fulfill the same basic requirements and functionalities as the v/f control remote-end HVDC station. Has the minimum capabilities listed in Table 6. Is able to operate in parallel with other GFM converters in the isolated AC system.

3.4 Parallel operation of remote-end HVDC converters

An important functionality for future multi-terminal HVDC grids for large scale wind power integration is the ability to operate remote-end HVDC converters in parallel on the AC side. System operators and PPM owners desire the operational flexibility to be able to AC interconnect the remote systems for optimization purposes, maintenance, or unplanned outages.

Figure 9 show a HVDC system topology, where the HVDC converters are interconnected on the AC side. It could either be a single pair of bi-pole converters that are interconnected on the AC side, or all four remote-end HVDC converters that are interconnected by a line or bus.

In this case, each HVDC VSC need to have the functionality to operate in parallel with other AC voltage sources. This can be solved by introducing adjustable droop functionality for both voltage and frequency control, and the HVDC converter stations will no longer be displaying the so-called *fixed* voltage source behavior associated with V/f control mode. This could be P/f and Q/V droops which would be beneficial for the AC connection of several offshore converters as well as for the split AC busbar on the same converter station.

The remote-end HVDC converter stations operating in parallel with voltage and frequency droop control functionality will by design display very similar characteristics as GFM converters with the functionalities defined in Section 2.5, and may very well be defined as GFM control as recent working groups suggest [32][33].

Thus, rather than using the terminology *V/f control with droop for parallel operation*, the GFM control terminology and definition could be applied in this case instead.

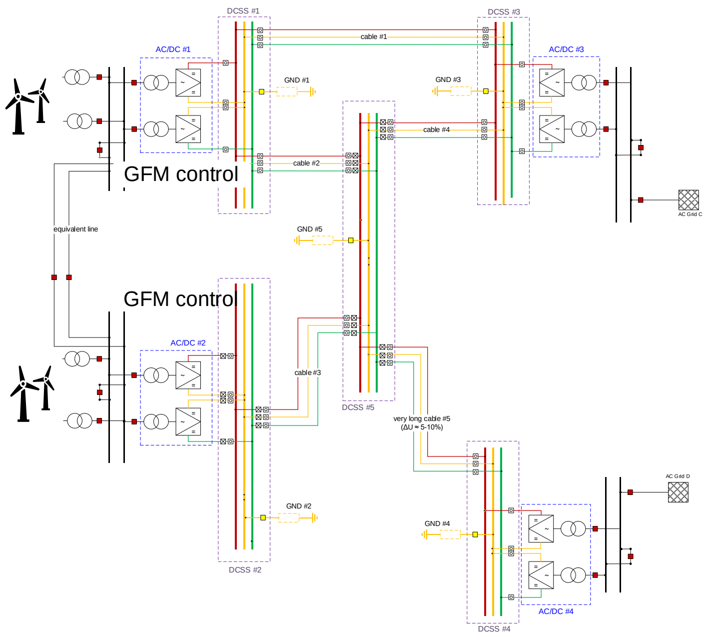

Figure 9. Illustration of parallel operation of V/f controlling remote-end HVDC converters.

Parallel operation of remote-end HVDC converters becomes a multi-vendor AC interoperability problem, as interconnection on the AC side may lead to adverse interactions between the parallel HVDC converters as well as PPMs. For stable operation the remote-end GFM must be carefully tuned.

Another aspect is an emphasized system operator responsibility in the isolated AC system when multiple remote-end HVDC converters operate in parallel. In case of an unplanned spontaneous outage of an HVDC cable or converter station, there may be an excess of power infeed from the offshore wind power, which cannot be transmitted due to insufficient capacity. This may lead to overloading of the remaining remote-end HVDC converter stations and risk of instability in the isolated AC system, unless the necessary wind power is ramped down or disconnected sufficiently fast while excess power may have to be handled by chopper systems. When there are multiple vendors in the form of HVDC OEMs and PPM owners and OEMs, the relevant system operator must coordinate and take responsibility of ensuring system security in the isolated AC system.

If each HVDC VSC is operating its own islanded offshore grid in fixed V/f control mode, the AC interactions are limited to one HVDC VSC and one PPM.

As part of the InterOPERA Task 2.4 objective, the goal is to standardize the functional requirements to remote-end V/f control, or remote-end GFM control as suggested, of HVDC VSC and to improve the capability for parallel operation with reduced multi-vendor interoperability risk.

Functional requirements for remote-end HVDC control:

1. The remote-end HVDC converters shall be capable of operating in AC parallel connection with other remote-end HVDC converters in an isolated AC system.
2. Parallel operation is defined as connection to the same AC bus, with very small impedance in between.
3. The reference values for voltage and frequency shall be externally adjustable
4. The remote-end HVDC station control shall have adjustable droop coefficients for voltage and frequency.
5. Parallel operation with other remote-end HVDC converters shall not lead to adverse control interactions.
6. Parallel operation with other remote-end HVDC converter stations shall not lead to undamped resonances.
7. The remote-end HVDC converters should limit any changes in control mode during transients to avoid the excitation of adverse interactions.
8. Voltage and frequency droop functions should respond in a similar timescale to avoid unnecessary interactions or oscillations.

3.5 Temporary islanding: FRT of DC-connected PPMs due to HVDC converter blocking

In most HVDC system applications for large-scale offshore renewable integration, the power park modules rely on the remote-end HVDC converters to generate an AC voltage source for the PPMs to synchronize to. However, due to various probable causes, there is a risk that the HVDC converter loses controllability and is unable to generate a reliable AC voltage source for the offshore grid. These causes could be temporary HVDC control system malfunction or blocking of the HVDC converter switching due to faults in the DC grid. This loss of controllability of the remote-end HVDC converter station is within this document defined as *fault-ride-through* (FRT) as seen from the DC connected PPM and refers to the absence of a stable voltage and frequency reference for the PPM.

The FRT can comprise unstable AC voltage, frequency or phase angle but also temporary islanding, caused by inhibition of switching and opening of AC breakers in the HVDC station. In any of these cases, and in particular if the disturbance is short term temporary, it is desirable that the PPM does not trip, which would require re-energization and can compromise the security of supply and loss of revenue. Thus, it is desirable that the DC connected PPMs have the capability of withstanding and riding through an event, where the AC voltage generated by the HVDC converter is disrupted temporarily.

This has been formulated in InterOPERA objective 5, where the goal is to demonstrate the capability of DC connected PPMs to ride-through a blocking of the HVDC converter of up to 300 ms. This implies that the DC connected PPM shall not trip when faced with the particular case of temporary islanding, seen as a high impedance fault, being able to self-synchronize and remain energized until normal HVDC converter operation and voltage is restored.

The blocking of the remote-end HVDC converter and temporary islanding may in some cases be identified as a three-phase fault by the DC connected PPMs, where the LV-FRT function will react. This does not guarantee resynchronization of the PPMs in every case and can be an extra challenge, as additional control interactions are in place, especially with grid-following control.

The FRT requirement may or may not indirectly impose the need for grid-forming control of the PPM modules. However, this is to be explored as part of the grid-forming demonstration in WP2 and WP3 of InterOPERA for Objective 5. It is essential that the requirement focuses on the functional requirement to ride through the event and not on the implementation or solution space.

With regards to the exact functional formulation of this ride-through capability of the DC-connected PPMs it is suggested to adapt a similar wording used in Section 5.10.4 of TenneTs system needs and functions for DC-connected PPMs [35]. The proposed requirement text then becomes "*DC-connected PPMs shall be capable of riding-through HVDC converter blocking by self-synchronizing with stable and smooth transition towards and from island mode of system operation (islanding), without interruption, in a continuous manner".*

With respect to the time duration of this capability, it is stated as part of InterOPERA Objective 5, that 300 ms ride-through capability is the goal of demonstration. However, in Section 7.3.1 of TenneTs grid forming control study requirements [36] a minimum time-duration of 150 ms has since been stipulated, which is half of the Objective 5 target. Thus, it is proposed that 150 ms is the minimum design criteria within InterOPERA, while is shall be explored if 300 ms can be achieved feasibly without enforcing significant cost on the PPMs in the form of energy-storage or other additional investment.

4 Chapter 4: Use cases of GFM control in HVDC systems

GFM control can be applied in multiple ways in HVDC systems. This section introduces conceptual examples of how grid-forming control could be considered in multi-terminal multi-vendor HVDC systems for wind power integration. The focus is on describing the overall control chain when grid-forming performance is expected and the interdependencies between the subsystems in the multi-terminal system in order to secure stable operation.

This section will list some of the options, from which some will be selected for demonstration in InterOPERA Work Package 3. The concepts that are to be demonstrated in accordance with the InterOPERA Objective 5 are:

1) GFM by an onshore HVDC converter with support from another synchronous area
2) GFM by an onshore HVDC converter with support from DC-connected PPMs
3) Temporary islanding of DC connected PPMs due to HVDC converter blocking[7]
4) Parallel operation of remote-end HVDC converter stations

In order to illustrate the grid-forming concepts in multi-terminal HVDC systems the following cases will take basis in the topology shown in Figure 10. The topology corresponds to the demonstrator Step E as proposed by Task 3.1 in WP3 of InterOPERA and consists of 2 offshore converter terminals AC/DC #1 and AC/DC #2, and 2 onshore converter terminals AC/DC #3 and AC/DC #4.

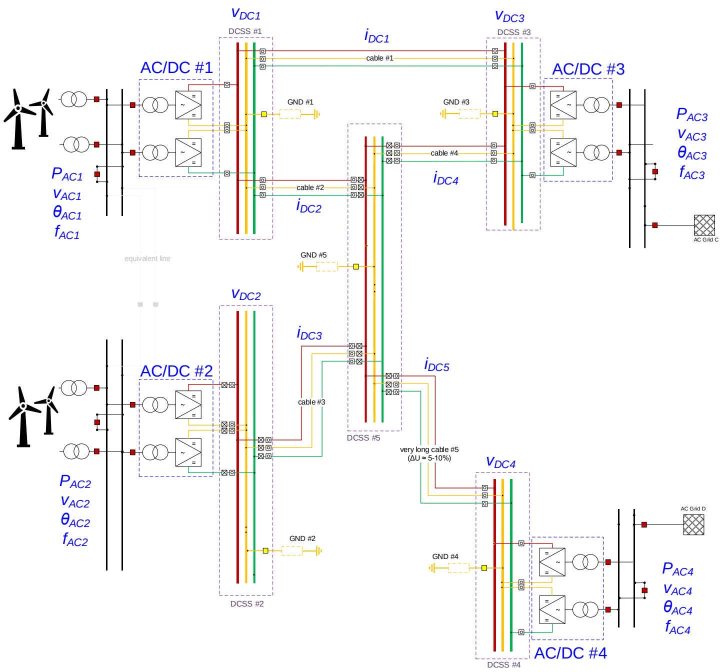

Figure 10. Four terminal HVDC system based on WP3.1 Step E.

[7] Refered to as DC FRT capability of DC-connected PPMs in the InterOPERA grant agreement.

4.1 Control chain options for HVDC stations being part of a multi-terminal multi-vendor HVDC system

The importance of coordinating the active power control chain with DC voltage control and grid-forming is discussed in Section 3.1. In this section different configurations of control options across a multi-terminal HVDC systems are discussed, with the aim to support the understanding, and be used as reference for the split of the technical requirements between AC and DC side especially among the HVDC converter stations, remote-end HVDC station and DC connected PPMs.

Based on this, different options can be defined for how DC voltage control and grid-forming can be coordinated. This control coordination can be seen as a coordination of different functions that each HVDC converter station has including modes of operation in conjugation with the selection of default parameters from a given range.

The control configurations are listed in Table 9. The HVDC converters are labelled according to the station numbers in Figure 10.

- Concept #1 and Concept #2 is without GFM support from the DC connected PPMs
- Concept #3 and Concept #4 is with GFM support from the DC connected PPMs

In each case listed in Table 9 the GFM performance that can be achieved in the HVDC converter station connection point to the synchronous area is expected to be different. The difference is expected to be most significant associated with high active power transfer, being phase jump power, inertial active power or positive damping power.

In Concept 1 high inertial active power can be achieved at AC/DC#3, as the other synchronous area acts as source for the GFM power while AC/DC#4 keeps the DC voltage constant.

In Concept 2 less inertial active power is expected to be achievable than in Concept 1, as both onshore HVDC converter stations, AC/DC #3 and #4 share the duty of Vdc droop control.

In Concept 3 the inertial active power achievable highly depends on the capability of the DC connected PPMs and the energy margin available in either upwards or downwards direction.

In Concept 4 the GFM functionality as well as the Vdc droop control duty is shared among all HVDC converter stations. The inertial active power that can be achieved at AC/DC #3 depends on what can be delivered by the DC connected PPMs and by the AC grid at AC/DC #4 before reaching any DC voltage limits. The more power can be delivered by the DC connected PPMs, the lower is the risk of reaching limits at the DC connection point at AC/DC #4.

Concept 4 can be varied in several ways depending on the GFM performance requirements in either of the AC connection points, AC/DC #3 or AC/DC #4. By adjusting the droop coefficient either onshore HVDC converter can be changed to be a near constant Vdc node, while the other onshore HVDC station can be designed with high phase jump active power and inertial active power. This flexibility in the overall design may alleviate the performance requirements for the GFM control of the DC connected PPMs in Concept 4.

Table 9. Control chain concepts for stable operation in an HVDC system with a 4-terminal topology.

	Control modes assigned					
	Remote-end HVDC converter station		HVDC converter station		DC-connected PPM	
	AC/DC #1	AC/DC #2	AC/DC #3	AC/DC #4	PPM #1	PPM #2
#1	V/f	V/f	GFM	V_{dc}	GFL	GFL
#2	V/f	V/f	GFM-V_{dc} droop	GFM-V_{dc} droop	GFL	GFL
#3	V_{dc} droop	V_{dc} droop	GFM	GFM	GFM	GFM
#4	GFM-V_{dc} droop	GFM-V_{dc} droop	GFM-V_{dc} droop	GFM-V_{dc} droop	GFM	GFM

4.2 Concept #1: GFM with support from another synchronous area

In this control chain concept one onshore HVDC converter (AC/DC #3) is in normal GFM control operation, and the other (AC/DC #4) is in Vdc control mode. The remote-end HVDC converters are in the conventional V/f control mode and the PPMs are in GFL control mode. AC/DC #3 can be tuned with high inertia active power response and damping, as the other synchronous area interfaced by AC/DC #4 is assumed to always support the other area. Remote-end HVDC converters are in V/f control and DC-connected PPMs are in GFL control.

This concept is relatively easy to demonstrate, but the real project application of it is hard to imagine as it requires that one area is willing to support the other, unless one AC grid is significantly weaker than the other AC grid, justifying the one-sided support.

4.3 Concept #2: GFM and Vdc droop control of onshore HVDC converters

In this control chain concept both onshore HVDC converters, AC/DC #3 and #4, are grid-forming operation with minimum capabilities as described in Section 3.2, with the purpose of being able to operate in a low short-circuit ratio grid and remain stable, but without providing high inertia for the power system. AC/DC #3 and #4 also have the duty of V_{dc} droop control. For robust V_{dc} droop control, the converters are tuned to have very low inertia response, and the fast transient active power exchange between AC/DC #3 and #4 is expected to be low. The GFM control is designed to limit the active power according to the DC voltage ranges specified in in accordance with InterOPERA D2.2 [31] The remote-end HVDC converters are in V/f control mode and the PPMs are in GFL control mode.

4.4 Concept #3: Offshore GFM by DC-connected PPMs to support the onshore system

In this control chain concept, the DC-connected PPMs have the full functionality and responsibility of creating the AC voltage in the isolated offshore grid. The remote-end HVDC converter station instead has primary duty of DC voltage control and are configured in V_{dc} droop control. This is a fundamental difference from the conventional control chain for offshore renewable energy integration with HVDC VSC as introduced in the beginning of Section 3.2. This concept should relief the onshore HVDC converters AC/DC #3 and #4 from the V_{dc} control duty, such that they can be configured with full GFM control, including significant inertial response. However, this control chain is considered very novel and not fully developed. Firstly, it relies on the offshore PPMs to be grid-forming and provide a stiff voltage source for the remote-end HVDC converter station to synchronize to. This may cause the need to work in curtailed operation or apply energy storage devices. Secondly the active power flow coordination between HVDC and DC PMMs needs to be reworked and may rely on additional communication in opposition to the conventional control chain, which is even more challenging in a multi-vendor setup.

Without energy storage the DC-connected PPMs will have to operate at a lower active power set point than the available wind power, in order to leave an energy margin for GFM control actions resulting in a fast active power increase. This could be negative voltage angle jumps in the onshore network which through the control chain will lead to positive active phase jump power provided by the DC PPM. On the other hand, negative phase jump power can always be delivered without storage as long as the PPM is producing active power, but the performance may be limited by the electrical and mechanical design constraints of the WTGs.

Description of the assumed behaviour during onshore negative AC voltage phase jumps:

When there is a negative phase jump in the grid voltage at PoC in the upper synchronous area, the AC/DC #3 shall deliver positive phase jump active power to the grid. The delivery of phase jump active power shall fulfill the following requirements.

1) The phase jump active power shall be delivered inherently following the phase jump in the grid voltage.
2) The amount of delivered phase jump active power depends on the amount of phase jump in the grid voltage, however, the delivered active power need not make the total power output exceed the over-current capability of the HVDC converter. After reaching the hardware limit, the converter shall maintain the maximum current output when relevant and stay connected to the grid.

The extraction of extra power from the HVDC grid will induce a decrease in the DC voltage. In such case, HVDC converter #1 and #2 are responsible for regulating the DC voltage back to the normal value. To recover the DC voltage, the HVDC converters and cables need to be charged and the energy comes from the offshore PPMs.

The extraction of energy from the PPMs is seen as a negative phase jump at the AC PoC which WTGs are connected to. In this case, the WTGs in GFM mode and react to the phase jump automatically. They will deliver phase jump active power to the AC side of offshore HVDC converters #1 and #2.

The delivery of the phase jump active power shall fulfill the following requirements:

1) The phase jump active power shall be delivered inherently following the phase jump in the voltage at AC PoC.
2) The amount of delivered phase jump active power depends on the amount of phase jump in the voltage, however, the delivered active power need not make the total power output exceed the

over-current capability and mechanical constraints of the WTG converters. After reaching the hardware limit, the WTGs shall maintain the maximum current output when it is relevant and stay connected to the grid. Besides, the WTGs operate in de-loading mode in such case. Therefore, depending on the operating point, the amount of delivered phase jump active power need not make the total power output exceed the available maximum power from the WTGs.

The HVDC converter #4 may also react based on the active power deviation seen at its terminal, since it is also in GFM control mode.

Description of the assumed behaviour during onshore positive AC voltage phase jumps

When there is a positive phase jump in the grid voltage at PoC in the upper synchronous area, the HVDC converter #3 shall absorb phase jump active power from the grid. The absorption of phase jump active power shall fulfill the following requirements.

1) The phase jump active power shall be absorbed inherently following the phase jump in the grid voltage.
2) The amount of absorbed phase jump active power depends on the magnitude of phase jump in the grid voltage. The absorption of active power will lead to a decrease in the total power output from the HVDC converter station #3 to the onshore AC synchronous area. Depending on the positive phase jump magnitude, a transient negative total power output from the HVDC converter #3 may result (transient power reversal).

The injection of extra power to the DC grid will induce an increase in the DC voltage. In such case, HVDC converter #1 and #2 are responsible for regulating the DC voltage back to the normal value. To recover the DC voltage, the HVDC cables need to be discharged.

This will be done by the DC-connected PPMs which will reduce their active power output in response to the increasing phase angle in the offshore AC grid.

The HVDC converter #4 may also react based on the active power deviation seen at its terminal, since it is also in GFM control mode.

Description of the assumed behaviour in response to a fast frequency decrease in the onshore system

When there is a frequency drop event, this could be a -2 Hz/s RoCoF in the upper synchronous area, the HVDC converter #3 shall deliver positive inertial active power to the onshore AC grid. The delivery of inertial active power shall fulfill the following requirements.

1) The inertial active power shall be delivered immediately following the frequency change in the grid.
2) The amount of delivered inertial active power is proportional to the RoCoF. The delivery of the active power will lead to an increase in the total power output from the HVDC converter #3 to the onshore AC synchronous area, however, the delivered active power need not make the total power output exceed the over-current capability of the HVDC converter. After reaching the hardware limit, the converter shall maintain the maximum current output when relevant and stay connected to the grid.

The extraction of extra power from the HVDC grid will Induce a decrease In the DC voltage. In such case, HVDC converter #1 and #2 are responsible for regulating the DC voltage back to the normal value. To recover the DC voltage, the HVDC cables need to be charged and the energy comes from the offshore AC system which sees a fast load increase at the AC PoC which WTGs are connected to. In this case, the WTGs operate in GFM mode and react to the load change automatically. The temporary power imbalance between the mechanical power input and electrical power output (load) will induce a frequency drop in the offshore AC grid where the PPMs are. In such case the WTGs will deliver inertial active power to the AC side of offshore HVDC converters #1 and #2. The delivery of the inertial active power shall fulfill the following requirements.

1) The inertial active power shall be delivered immediately following the load increase at AC PoC.
2) The amount of delivered inertial active power is proportional to the RoCoF in the offshore AC grid, however, the delivered active power need not make the total power output exceed the over-current capability of the WTG converters. After reaching the hardware limit, the WTGs shall maintain the maximum current output and stay connected to the grid. Besides, the WTGs operate in de-loading mode in such case. Therefore, depending on the operating point, the amount of delivered inertial active power need not make the total power output exceed the available maximum power from the WTGs.

The HVDC converter #4 may also react based on the active power deviation seen at its terminal, since it is also in GFM control mode.

Description of the assumed behaviour in response to a fast frequency increase in the onshore system

When there is a frequency increase, this could be a 2 Hz/s RoCoF in the upper synchronous area, the HVDC converter #3 shall absorb inertial active power from the onshore AC grid. The absorption of inertial active power shall fulfill the following requirements.

1) The inertial active power shall be absorbed immediately following the frequency increase.
2) The amount of absorbed inertial active power is proportional to the RoCoF in the onshore AC grid. The absorption of active power will lead to a decrease in the total power output from the HVDC converter #3 to the onshore AC synchronous area.

The injection of extra power to the HVDC grid will induce an increase in the DC voltage. In such a case, HVDC converter 1 and 2 are responsible for regulating the DC voltage back to the normal value. To recover the DC voltage, the HVDC cables need to be discharged.

This will be done by the DC connected PPMs which will reduce their active power output in response to the decrease in load in the offshore AC grid.

The HVDC converter #4 may also react based on the active power deviation seen at its terminal, since it is also in GFM control mode.

System security risks to address:

It is evident that there are close interactions between realizing AC-side GFM functionalities and DC-side functionalities at the same time. The following are some challenges and possible risks that may occur from the interactions.

- The exchange of power as a result of fulfilling GFM functionalities with the onshore AC system has an influence on the DC voltage.

- Positive AC voltage phase jump leading to an increase in DC voltage risk activation of DC choppers/ DBS that may be installed on the DC side
- Grid-forming will lead to a significant increase in the dynamic active power coupling between the onshore AC system and the offshore AC system through the MTDC system, which may lead to an increase in interaction risks. Thus, a dilemma appears where TSOs want grid-forming to stabilize the onshore AC system, but at the consequence of potentially lower robustness of the offshore system. The risk of interaction issues due to GFM control should be studied and mitigated carefully.
- In cases where multiple PPMs, potentially from multiple developers and OEMs, are connected at the remote-end, the coordination of the GFM responsibility between the PPMs is critical to limit the risk of system security compromising events, similarly, a single PPM typically consists of multiple WTGs distributed over a larger geographical area where the internal coordination between GFM and GFL control is critical.

It Is very Important to have proper system level design coordination to avoid risks from conducting AC-side GFM functionalities to fulfilling DC-side functionalities.

4.5 Concept #4: Distributed GFM control for HVDC stations and DC connected PPMs

Another way to utilize GFM capability from DC-connected PPMs to support the onshore grid is by distributing the grid-forming control across multiple or even all converters in the multi-terminal HVDC system. In this case all HVDC converter stations are configured in GFM-V_{dc} droop control mode, remote-end HVDC stations as well as onshore HVDC stations. The DC connected PPMs are similar in GFM control mode. The onshore and remote-end AC systems will be tightly coupled together and disturbances in AC phase angle onshore in AC/DC #3 will distribute as disturbances in AC phase angle at all other AC interfaces at AC/DC #1, #2 and #4 due to the grid-forming action in the form of phase jump active power. The DC-connected PPMs are grid-forming and will contribute to the phase jump power as long as it is within their operating limits. At full wind speed they will be able to deliver high negative phase jump power in response to positive voltage phase jumps. If GFM contribution is required at full wind speed, an energy reserve is necessary in order to deliver transient active power increases. However, from a system security perspective and depending on the application it may not be necessary nor feasible that PPMs contribute in the positive active power direction when operated at maximum wind speed. This illustrates the benefits of defining the GFM performance requirements asymmetrically for the positive and negative power directions.

The system and control chain behavior are similar to that of Concept #3, except that the onshore converter AC/DC #4 is expected to contribute and react to the disturbance in DC voltage due to the GFM-V_{dc} droop control functionality.

Part III

Subtask 2.4.3

Formulation of basic functional requirements for grid-forming control

5 Chapter 5: Proposed GFM functional requirements

This chapter presents the functional requirements for GFM control proposed by InterOPERA. The requirements are tabulated in Table 10. Considering a multi-terminal multi-vendor HVDC system scenario, the GFM functional requirements in this chapter are formulated at the HVDC converter station level (onshore HVDC converter stations and remote-end HVDC converter stations) and in the HVDC interface point for the DC connected PPMs. For simplicity, the term 'GFM converter' is used to represent an onshore HVDC converter station, an offshore HVDC converter station, or a DC-connected PPM in the context when any of them has GFM functionality.

The requirements are structured in the following groups and order:

A. General GFM requirements for HVDC converter stations and DC connected PPMs
B. Withstand requirements of GFM converters
C. Requirements specific for HVDC converter stations including remote-end HVDC converters
D. Requirements specific for DC connected PPMs
E. Requirements for self-synchronization functionality
F. Requirements for phase jump active power functionality
G. Requirements for inertial active power functionality
H. Requirements for inherent reactive power functionality
I. Requirements for positive damping power functionality
J. Optional requirement: Black-start functionality
K. Optional requirement: Sink for voltage unbalances functionality

Within the scope of work in InterOPERA, no dedicated oversizing of hardware or additional energy storage elements is required to deliberately fulfill the GFM functional requirements specified in this chapter. The sizing of relevant hardware may be the same as in the case where GFM functionality is not required.

For demonstration purposes of the functionalities a power margin may have to be reserved for the GFM control in some scenarios, e.g. operating the HVDC converter station below rated power for demonstrating an increase in power output due to GFM control or operating the offshore wind power plants in a curtailed operation below the available wind power.

It is worth noting that the requirements should be considered as three separate sets of requirements for the three types of subsystems (onshore HVDC converter stations, remote-end HVDC converter stations, and DC-connected PPMs). For each set of requirements, it is assumed that the subsystem this set applies to is in GFM control, while the other subsystems in the same HVDC system could have any control mode as long as they together make the whole HVDC system operationally feasible and stable.

Typically, the remote-end (offshore) HVDC converter station is in v/f control when connecting with DC-connected PPMs in previous and ongoing projects. However, the proposal presented for remote-end HVDC converter stations is that these can either be specified as v/f control converters or GFM control converters, and that it is up to the relevant TSO or system developer to specify the designated control mode for the specific remote-end HVDC station.

The v/f control mode is a proven and mature solution for isolated AC networks, while GFM control of remote-end HVDC systems is less mature, but may be beneficial for larger isolated AC systems with parallel operation of voltage source converters. Thus, whether the converter should be specified as v/f control converter or GFM control converter depends on the project goals and system characteristics.

Besides, in this chapter the focus is on GFM functional requirements at subsystem level (HVDC converter station or PPM), instead of operational regimes at the combined HVDC system level. This means that the source or sink of the power that is exchanged in fulfilling the GFM functionality is not addressed in this chapter, as this is more of an operational concern. It is a precondition that the source or sink of the power related with GFM functions is handled properly at operational level. Assuming the relevant power or energy is dispatchable, this chapter focuses on how the power or energy should be utilized to fulfil the GFM functionality.

For a DC-connected PPM, the GFM control is implemented at each WTG instead of at the power park controller. Hence, the expected GFM response in the requirements is the collective GFM responses from all the WTGs in the PPM but measured in the HVDC interface point (offshore AC POC).

The GFM functional requirements in this chapter are focusing on the characteristics of GFM converters in HVDC systems. However, it is important to emphasize that GFM functional requirements are not the only requirements applicable for grid connection under the network codes. Any GFM converter is expected to equally fulfill the requirements under the network codes, which the state-of-the-art GFL converters fulfill today. The existing network codes cover several other important aspects which are equally important as GFM functional requirements. As a basis, the GFM converter should fulfill every requirement in the NC HVDC that also applies to GFL converters today. However, a concern may be that while functional requirements mature and grid-codes develop, conflicts between the more novel GFM requirements and the existing grid code requirements may appear. In these cases, it is suggested that the relevant TSO takes the responsibility in deciding which requirement has priority.

A general remark for multi-terminal multi-vendor HVDC systems is that providing GFM functionality from the HVDC system has a lower priority compared to maintaining the DC voltage stability of the HVDC system. Hence, providing GFM functionality is constrained by DC voltage limits, which is reflected in the requirements.

5.1 Functional GFM control requirements

Table 10 lists the final functional requirements proposed in Task 2.4 of InterOPERA. In addition to the requirement text itself, there may be a supporting text with suggestions for performance criteria, evaluation method or suggestions for demonstration. This text appears in the third column if anything is suggested. The utilization of the demonstrator in WP3 of InterOPERA to further exhaust the GFM functional requirements is further discussed in Section 5.2.

Table 10. Final functional requirements for GFM control for HVDC converter stations and DC connected PPMs.

ID no.	Requirement text	Proposal for performance criteria and evaluation methods in InterOPERA
General GFM requirements for HVDC converter stations and DC connected PPMs		
A.1	The GFM converter shall behave as a controllable voltage source in series with an impedance (Thévenin equivalent). More specifically, it shall be able to maintain its internal voltage phasor nearly constant (can slowly change) in the first few milliseconds following a disturbance in the phase angle, frequency, or amplitude of the grid voltage.	-
A.2	The GFM converter shall fulfil the functional requirements Group D to Group H throughout the whole active power operating range if it is in normal operation, i.e., operating within its current, voltage and energy limits. It is a precondition for the functional requirements in Group D to H that the GFM converter is in normal operation. To avoid repetition, this precondition is not repeated in the following paragraphs.	-
A.3	If in withstand operation, i.e., any of its current, voltage and energy limits is reached, the GFM converter shall preserve its GFM capability whenever possible, while maintaining stable operation and staying connected to the grid. The GFM converter is only allowed to disconnect from the grid if the withstand limits and time-dependent voltage and frequency limits specified in the NC HVDC are exceeded [26].	-
A.4	The GFM converter may adapt its voltage-source characteristics when changing from normal operation to withstand operation. The transition between normal operation and withstand operation shall be as seamless and continuous as possible considering the characteristics and severity of the event disturbing the converter into withstand operation	-
A.5	The functional requirements in Group I (black-start) and Group J (sink for voltage unbalance) are non-mandatory optional GFM functionality for the GFM converter. They may be requested by the relevant TSO in agreement with the GFM converter OEM or PPM owner.	Black-start and sink for voltage unbalance not included in InterOPERA demonstration.
A.6	The GFM converter shall select GFM control mode only as directed by the relevant TSO.	To be decided within WP3 in preparation for the demonstrator.
A.7	The priority ranking between GFM control and other HVDC system control and protection parameters, shall be agreed between the relevant TSO and the HVDC system owner.	Proposed to follow the priority ranking in the EG CROS report: 1. network system and HVDC system protection 2. grid forming capability 3. active power control for emergency assistance 4. automatic remedial actions 5. FSM, LFSM O/U 6. power gradient constraint

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<table>
<tr><td>A.8</td><td>For design and compliance testing of GFM control the relevant TSO defines the performance requirements for compliance testing of the GFM converter.
1) Performance requirements shall be formulated individually for onshore HVDC converter stations, remote-end HVDC converter stations and DC connected PPMs.
2) Performance requirements shall be formulated for each of the GFM control functionalities:
• Group D: Self-synchronization
• Group E: Phase jump active power
• Group F: Inertial active power
• Group G: Inherent reactive power
• Group H: Positive damping power</td><td>Performance requirements should be carefully considered for HVDC converter stations with DC voltage control duty and DC connected PPMs. Here the minimum requirements described in Section 3.2.5 should be considered.</td></tr>
<tr><td>A.9</td><td>The GFM converter shall be able to share active and reactive power loads with other power-generating modules in the system using the principle of droop similar to the operation of conventional synchronous generators. Here, droop is not meant to signify the type of GFM control to be implemented but rather implies the proportional characteristic in the sharing of power and the property of coordination and cooperation with other power-generating modules that the GFM converter shall possess.</td><td>-</td></tr>
<tr><td>A.10</td><td>The GFM converter shall be able to operate stably in weak and strong grid conditions. The relevant TSO shall specify the minimum and maximum short-circuit level and X/R ratio in the point of connection. Other relevant data may be provided in order to define the operational boundaries in the connection point in agreement between the GFM converter owner and the relevant TSO.</td><td>Network equivalent data as per WP3 of InterOPERA</td></tr>
<tr><td>A.11</td><td>The HVDC converter station and DC connected PPM shall be capable of operating in parallel with other HVDC converter station and/or DC connected PPMs in the isolated AC grid. This requirement is not limited to GFM converters but applies to all HVDC converters and DC connected PPMs.
1. The reference values for generating voltage and frequency shall be externally adjustable.
2. The parallel operating converters shall have adjustable droop coefficients for voltage and frequency.
3. Parallel operation with other HVDC converters and/or DC connected PPMs shall not lead to adverse control interactions.
4. Parallel operation with other HVDC converters and/or DC connected PPMs shall not lead to undamped resonances.
5. HVDC converters and/or DC connected PPMs should limit any changes in control mode during transients to avoid the excitation of adverse interactions.
6. The voltage and frequency droop functions should respond in a similar timescale to avoid unnecessary interactions or oscillations</td><td>This capability can be verified by demonstrating interconnection between remote-end HVDC converter station #1 and remote-end HVDC converter station #2 as shown in Figure 9 in Section 3.4 in the absence of adverse control interactions.

P-f droop, Q-V droop, ramp-rates should be open and adjustable.</td></tr>
</table>

Withstand requirements of GFM converters		
B.1	The GFM converter shall fulfill the general withstand requirements for GFM and GFL converters as required in the NC HVDC and its national implementation. If there is any conflict between the NC HVDC and the withstand requirements specified in B.2, B.3 and B.4 the NC HVDC shall have priority	
B.2	The GFM converter shall be able to withstand a maximum phase jump at the point of connection or HVDC interface point as specified by the relevant TSO. The relevant TSO may specify the maximum phase jump in a range from 10° to 45°, where the GFM converter shall remain connected and maintain synchronism with the AC grid. The maximum phase jump withstand shall be specified individually for onshore HVDC converters, remote-end HVDC converters and DC connected PPMs. Post-disturbance power oscillations shall be sufficiently damped. The pre-disturbance conditions (such as GFM converter operating point and SCR) shall be defined by the relevant TSO.	Synchronous area connected HVDC converter station: 30 ° ([8]) DC connected PPM: ≥ 10 ° Remote-end HVDC converter station: ≥ 10 °
B.3	The GFM converter shall be able to stay connected to the connection point or HVDC interface point and operate stably when subject to frequency changes with RoCoF as specified by the relevant TSO. The RoCoF withstand shall be specified individually for onshore HVDC converters, remote-end HVDC converters and DC connected PPMs. 1. The specified RoCoFs together with their corresponding durations are considered non-consecutive in the requirement. It means that for compliance, each of the RoCoFs together with their corresponding durations is tested separately with a waiting period in between each test, where the next test is not applied before the frequency gets back to 50 Hz and the GFM converter reaches a steady state at its pre-defined power setpoints. 2. The relevant TSO and the GFM converter owner shall agree on the estimation method of frequency and calculation method of RoCoF in specific projects. If RoCoF is used for loss of mains protection of the GFM converter, the RoCoF threshold in the protection shall be set at higher values than the ones specified above.	Synchronous area connected HVDC converter station: ± 5 Hz/s over a period of 0.25 s ± 2.5 Hz/s over a period of 0.5 s ± 1.25 Hz/s over a period of 2 s DC connected PPM: ± 2 Hz/s over a period of 1 s Remote-end HVDC converter station: ± 2 Hz/s over a period of 1 s (The values are aligned with the EG CROS report [34])
B.4	The GFM converter shall be able to withstand sudden large changes in the grid impedance, which lead to step changes of SCR at its point of connection and maintain stable operation without blocking or tripping. Depending on the magnitude of any given SCR step, the TSO shall specify if the GFM unit is allowed to shift from previous power levels after the SCR change as long as it stays connected to the grid and operates stably.	For synchronous area connected HVDC converter stations the SCR step shall go from SCR_{min} to SCR_{max} and from SCR_{max} to SCR_{min} values according to the WP3 demonstrator specifications.

[8] The default value for onshore HVDC converters is suggested to be 30° in accordance with the FNN guideline [3], while the maximum phase jump can be lower in the isolated AC system offshore for the DC connected PPMs and remote-end HVDC.

	The range of SCR step changes shall be specified by the relevant TSO and shall be coordinated with Requirement B.2 such that it does not lead to a larger change in voltage phase angle than the maximum phase jump withstand capability specified in Requirement B.2. Another system strength indicator than SCR may be applied in agreement between the relevant TSO and the GFM converter owner. The relevant TSO and the GFM converter owner may agree to utilize phase jump testing to show compliance with the SCR step change requirement instead.	SCRmin should be within the limit that guarantees the transfer of pre-disturbance active power.
Specific requirements for HVDC converter stations including remote-end HVDC converters		
C.1	For compliance verification either by simulation or tests the expected GFM response from the HVDC converter station in an HVDC system is evaluated at both the AC and DC connection point of the HVDC converter station.	
C.2	The HVDC converter station shall be configurable to have GFM control and Vdc droop control mode activated simultaneously. 1. The GFM functionality of the HVDC converter station shall be coordinated with the DC voltage control scheme and DC voltage ranges of the HVDC system as specified by the relevant TSO. 2. The GFM HVDC converter station with Vdc droop control receives its DC voltage reference and droop gains externally for different DC voltage regions	Vdc droop control mode shall fulfill the requirements stipulated in InterOPERA D2.1 [31]
C.3	The GFM functionality of HVDC converter stations shall be limited by DC voltage ranges as specified by the relevant TSO. The applicable DC voltage limits could be project specific[9] and determined in agreement between the relevant TSO and the GFM converter OEM. 1. The GFM functionality shall be unconstrained by the DC voltage within the normal operation range defined by the lower DC voltage threshold value Udc1 and the upper DC voltage threshold value Udc2 or as otherwise defined by the relevant TSO. 2. When continuously exceeding the normal operation limits and entering the limited operating range, between the lower limits Udc1 and Udc4, and the upper limits Udc2 and Udc3, the active power response associated with GFM control shall be limited proportional to the deviation in DC voltage in order to contain the DC voltage. The limitation of the GFM active power shall be seamless.	DC voltage ranges as specified in D2.1 [31]. Normal, alert and emergency state definitions as specified in D2.1 [31]. The limiting of GFM should be proportional according to Figure 8 in Section 3.2.3 whenever possible.
C.4	The relevant TSO may specify a time-duration, t_{dclim}, in which the GFM action shall be allowed to transiently disturb the DC voltage at the DC connection point to the upper and lower thresholds, Udc3 and Udc4 without limiting the GFM power due to DC voltage constraints	The feasibility of this requirement is suggested to be further investigated and determined as part of WP3 of InterOPERA. A value of t_{dclim} equal to 100 ms is considered for exploration.

[9] As multi-terminal multi-vendor HVDC systems standardize DC voltage ranges and limits could be generally specified.

C.5	When in standalone operation as specified in Requirement D.1, the HVDC converter is not required to have the Vdc control function activated at the same time. The HVDC converter may have Vdc droop control function under the condition that there are other DC voltage controlling HVDC stations in the HVDC system.	
C.6	The GFM converter by itself shall not cause undamped oscillations at its DC or AC connection points due to the GFM functionality.	DC voltage oscillations induced by the GFM functionality could be characterized by propagation to the offshore AC grid using the InterOPERA demonstrator.
	Requirements specific for DC connected PPMs	
D.1	For DC connected PPM compliance verification by means of tests or simulation of the GFM control shall be done and evaluated at the PPMs connection point in the isolated AC grid (HVDC interface point).	-
D.2	DC-connected PPMs are exempt from functional requirement Group I – Positive damping power. Although exempt from the capability to deliver positive damping power, DC connected PPMs are not allowed to cause significant undamped power oscillations in the isolated AC system. The requirements to power oscillation damping shall follow the NC HVDC or its national implementation.	-
D.3	DC-connected PPMs shall be capable of riding-through HVDC converter blocking by self-synchronizing with stable and smooth transition towards and from island mode of system operation (islanding), without interruption, in a continuous manner. The relevant TSO shall specify a minimum time-duration of which the DC-connected PPM is able to ride-through.	Evaluated by HVDC converter blocking test. As per InterOPERA objective 5 the goal is to achieve 300 ms FRT capability which will be explored as part of the demonstrator. The minimum requirement is 150 ms as required in Section 7.3.1 of [36].
	Requirements for self-synchronization functionality	
E.1	The GFM converter shall be capable of standalone operation (when the last voltage source in the rest of the AC grid is lost), in which the frequency and voltage shall comply with those specified in Article 'X and Y' respectively in Commission Regulation (EU) 2016/1447 [26] or by the relevant TSO at national level, where applicable. 'X and Y' are '11 and 18', '47 and 48', or '39 and 40' respectively for an onshore HVDC converter station, a remote-end HVDC converter station, or a DC-connected PPM.	Evaluated by loss of the voltage source test as per FNN guideline [3]
E.2	In standalone operation, the voltage amplitude and frequency reference of the GFM converter shall be allowed to be controllable by the relevant TSO. This only applies to the onshore and remote-end HVDC converter stations.	-
E.3	When either to be connected to an isolated AC network or to be connected to a synchronous area, the GFM converter shall be able to synchronize to the AC network after the breakers are	Preconditions for synchronization to consider: ΔV < 10 %

	closed. The synchronization shall not impose perturbations on the system that lead to violations of frequency and voltage limits specified by the relevant TSO. The synchronization shall not cause tripping or blocking of any HVDC converter station or DC-connected PPM if any. The relevant TSO and the GFM converter owner shall agree on the specifications of suitable preconditions for the connection and synchronization procedure, for example, maximum differences in voltage amplitudes, phase angles between the grid voltage and the converter station terminal voltage. The relevant TSO and the GFM converter owner shall also agree on the synchronization method used in the synchronization procedure.	$\Delta f < 0.1$ Hz $\Delta\theta < 10°$
E.4	In grid-connected operation, the GFM converter shall be able to synchronize and operate stably with other power-generating modules, reactive power compensation devices and different types of loads in the system. The power-generating modules include both synchronous generators and power park modules (either GFM or GFL).	-
E.5	Interactions between the GFM converter and other GFM converters in the system shall not amplify the fluctuation of phase angle and cause instability. This shall be verified by means of a study in agreement with the relevant TSO and the GFM converter OEM and owner.	-
	Requirements for phase jump active power functionality	
F.1	The GFM converter shall be able to inherently inject or absorb phase jump active power to or from the AC grid in response to voltage phase angle changes at the point of connection or HVDC interface point, if the phase angle changes do not exceed the maximum values specified in withstand requirement B.3	-
F.2	The start of injection or absorption of the phase jump active power shall be immediate following the phase angle change. Further details shall be agreed between the relevant TSO and the GFM converter OEM and owner at the design phase of specific projects. For example, how much change in power is considered as the start of action in the phase jump active power, and measurement and calculation methods for active power.	Minimum 10 ° positive and negative phase jump suggested for performance evaluation. The GFM converter can be operated below P_{max} in order to reserve a power and energy margin for demonstration of the functionality. This could be at 50 % of P_{max}.
	Requirements for inertial active power functionality	
G.1	The GFM converter shall be able to inherently inject or absorb inertial active power to or from the AC grid in response to frequency changes in the grid, if the RoCoF does not exceed the maximum values specified in Section J. The start of injection or absorption of the inertial active power shall be immediate following the frequency change.	-
G.2	The performance and evaluation criteria for inertial active power shall be specified by the relevant TSO.	Maximum inertial active power test according to RoCoF values stipulated in Requirement B.3.

	For the purposes of compliance verification of inertial active power, the amount of inertial active power is calculated and shall be proportional to the average RoCoF. 1. The time duration of the RoCoF test shall follow the NC HVDC or its national implementation. 2. The maximum inertial active power shall be evaluated at the maximum RoCoF withstand value according to Article 12 of the NC HVDC or its national implementation. 3. The relevant TSO and GFM converter owner shall coordinate the measurement and calculation method of for active power. 4. If not specified by the NC HVDC or its national implementation the relevant TSO and the GFM converter owner and associated OEM shall agree on the estimation method of frequency and calculation method of RoCoF. 5. The relevant TSO may specify a minimum equivalent inertia constant H which should be derived from a RoCoF test.	Equivalent inertia constant derived from RoCoF test applying a fixed slow RoCoF (linear operation domain of the GFM) can be done in order to estimate the equivalent inertia using the expression: RoCoF=(Fo*DP)/(2*H*Srated) HVDC converters with Vdc control duty are not expected to have high inertial active power as per minimum capabilities in Section 3.2.5 The GFM converter can be operated below Pmax in order to reserve a power and energy margin for demonstration of the functionality. This could be at 50 % of Pmax. For DC connected PPMs this means operation below maximum power point, with an energy buffer, for the purpose of demonstrating the capability.
G.3	When the frequency change has stopped the active power operating point of the GFM converter shall be able to return to its pre-disturbance value if there is no change in its setpoint.	-
	Requirements for inherent reactive power functionality	
H.1	The GFM converter shall be able to inherently inject or absorb reactive power to or from the AC grid in response to amplitude changes in the grid voltage, if the voltage amplitude does not exceed the ranges and corresponding periods for operation specified in NC HVDC Article 'X' [26]. 'X' is '18', '48', or '39' respectively for an onshore HVDC converter station, a remote-end HVDC converter station, or a DC-connected PPM.	-
H.2	The start of injection or absorption of the inherent reactive power shall be immediate following the amplitude change of the voltage. Further details shall be agreed between the relevant TSO and the GFM converter owner. For example, how much change in power is considered as the start of action in the inherent reactive power, and measurement and calculation methods for reactive power.	Evaluated by voltage step test in the connection point from 1 p.u. to 1.1 p.u. and from 1 p.u. to 0.9 p.u. The inherent reactive power response will be proportional to the sum of the internal impedance and the physical impedance. The reactive power magnitude required could be specified in coordination with U-Q/Pmax-

		profile of Article 20 of the NC HVDC.
H.3	The injection or absorption of the inherent reactive power shall not rely on voltage measurements and changes of reactive power/current setpoints in the controls.	-
	Requirements for positive damping power functionality	
I.1	The GFM converter shall be able to provide positive damping of sub-synchronous frequency oscillations at the point the point of connection or HVDC interface point. Especially for sub-synchronous torsional interaction (SSTI), the GFM converter shall not adversely impact the damping of SSTI.	-
I.2	The start of provision of the positive damping power shall be immediate following the appearance of the sub-synchronous oscillations. Further details shall be agreed between the relevant TSO and the GFM converter owner at the design phase of specific projects. For example, how much change in power is considered as the start of action in the positive damping power, and measurement and calculation methods for power.	-
I.3	The GFM unit shall not introduce any new unstable oscillatory modes into the AC grid.	-
I.4	The method of evaluating the damping capability of the GFM unit shall follow Article 29 of the NC HVDC and its national implementation. If nothing is specified, the method shall be agreed between the relevant TSO and the GFM converter owner[10].	-
	Optional GFM requirement: Black start	
J.1	With an adequate energy source the GFM converter shall have the capability of energizing and restoring a passive or islanded network to which it is connected and controlling and maintaining the AC frequency and voltage of the AC grid within the ranges specified in Article 'X and Y' respectively in Commission Regulation (EU) 2016/1447 [26] or by the relevant TSO at national level, where applicable. 'X and Y' are '11 and 18', '47 and 48', or '39 and 40' respectively for an onshore HVDC converter station, a remote-end HVDC converter station, or a DC-connected PPM. This can be achieved either using GFM or V/f control mode. This decision must be made by agreement between the relevant TSO and the GFM converter OEM or owner. A seamless transition from V/f to GFM shall be ensured if V/f is used.	Not evaluated in InterOPERA
J.2	The GFM converter shall be capable of energizing all conventional power system equipment such as but not limited to transformers, overhead lines, cables and AC filters. Likewise, the GFM converter shall be capable of energizing auxiliary equipment and synchronizing with system supporting devices such as FACTS or synchronous condensers. The relevant TSO and the GFM converter owner shall agree on the capability and	Not evaluated in InterOPERA

[10] The damping capability can be evaluated by different methods [30], like frequency-domain analysis of the converter input impedance (harmonic impedance), time-domain impedance scan, and the approach of Network Frequency Perturbation (NFP) combined with a Nichols Chart [7], etc.

	availability of the black start function and the operational procedure.	
J.3	The GFM converter owner shall determine and provide any additional control implementations and equipment such as diesel back-up, batteries, etc. that are needed to be able to carry out black start.	Not evaluated in InterOPERA
J.4	In the black start process, the GFM converter shall have sufficient capability to handle and supply inrush currents during the energization of transformers and distribution feeders and starting auxiliary motors of conventional power plants, if any. Other inrush current mitigation methods could be accepted as well in agreement with the relevant TSO.	Not evaluated in InterOPERA
J.5	It shall be possible to adjust the frequency in the local AC grid between 47 and 52 Hz during the black start, which will be used to adapt the frequency before synchronization to another AC network.	Not evaluated in InterOPERA
J.6	The black start shall be possible to be performed remotely without presence of personnel in any of the HVDC converter stations or DC-connected PPMs in the HVDC system.	Not evaluated in InterOPERA
Optional GFM requirement: Sink for voltage unbalances		
K.1	The GFM converter shall not oppose or prevent the flow of negative sequence currents for voltage unbalances at the point of connection or HVDC interface point.	Not evaluated in InterOPERA
K.2	Within its total current capability and negative sequence current capability, the GFM converter shall be able to permit the flow of negative sequence current to reduce the voltage unbalance factor [29] no larger than 2% measured at the connection point or HVDC interface point. The relevant TSO and GFM converter owner shall agree on the details of measurement.	Not evaluated in InterOPERA
K.3	The negative sequence current capability of the GFM converter shall be sufficient to meet the load characteristics at the connection point and be determined by project-specific studies in agreement with the relevant TSO. If the provision of negative sequence current reaches an amount that introduces stress on the converter, reduction or limitation of the amount could be allowed in agreement with the relevant TSO.	Not evaluated in InterOPERA
K.4	In case of asymmetrical faults, the GFM converter shall be able to maintain a balanced internal voltage within its operating limits (only positive sequence voltage is controlled) and negative sequence current is allowed to flow. The negative sequence current shall meet relevant protection requirements specified by the relevant TSO.	Not evaluated in InterOPERA

5.2 Utilizing the InterOPERA demonstrator for feedback and iteration

As per InterOPERA objective 5, the goal is to push the state-of-the art by demonstrating grid-forming capabilities of multi-terminal multi-vendor HVDC systems with DC connected PPMs.

This section discus the application of the GFM functional requirements within the interoperability work stream in InterOPERA, specifically in WP2 and WP3. This involves:

1. Utilizing the demonstrator for exploration and learning
2. Detailing of the functional requirements for multi-vendor multi-terminal HVDC system under demonstration

As outlined in the literature study presented in Part I, the publicly available information on GFM control in multi-terminal HVDC systems and DC connected PPMs is very scarce or non-existent.

In InterOPERA Task 2.4 functional requirements have been formulated based on the GFM functional requirements that are being formulated widely in the industry for multiple different applications, such as battery storage systems and AC connected generation, in combination with the experience of the HVDC OEMs, wind power OEMS and developers and TSOs in order to make it as multi-vendor multi-terminal HVDC specific as possible.

However, it is challenging to predict if the GFM functional requirements outlined in Section 5.1 are sufficient or appropriate without the experience and feedback from real implementation of those requirements.

One particular challenge is that several of the functional requirements stipulated in Section 5.1 are so called *non-exhaustive* functional requirements meaning that they require further detailing in order to clarify the required performance. This is often expressed in statements such as "specified by the relevant TSO in coordination with HVDC or PPM owner", giving the freedom to make an either project specific or national detailing of the requirement.

However, for the control and protection solution for the demonstrator in InterOPERA, these non-exhaustive requirements need to be detailed further.

This will either be by providing details, agreements or quantifications to the functional requirements or indicating that a particular variable needs exploration or sensitivity analysis through the offline or real-time simulations that are to be carried out with the models representing the control and protection solutions.

This iteration comes with pre-design in deliverable D3.2, detailing of the functional requirements in deliverable D3.3 and finally the implemented solutions in offline EMT models in deliverable D3.4 and the control and protection replicas in Deliverable D3.5. This process is illustrated in Figure 11.

When the HVDC OEMs and wind power OEMs receives the GFM functional requirements from D2.2. they will be processed into design and implementation of compliant solutions.

If the functional requirements stipulated in Chapter 5 are either unclear, not detailed enough, too restrictive, not feasible or any other issue that may arise in the process of implementing solutions, the GFM functional requirements needs to be iterated and improved in order to reach a sufficient level of quality in the functional requirements.

Thus, some update to the material in D2.2 is expected before reaching the detailed GFM functional requirements in InterOPERA and, finally, the proposal for new articles in the network code for HVDC and DC connected PPMs in deliverable D2.5.

This direct feedback and iteration opportunity between functional requirements and vendor implementation and solution is the real strength of the interoperability work stream and demonstrator of the InterOPERA project.

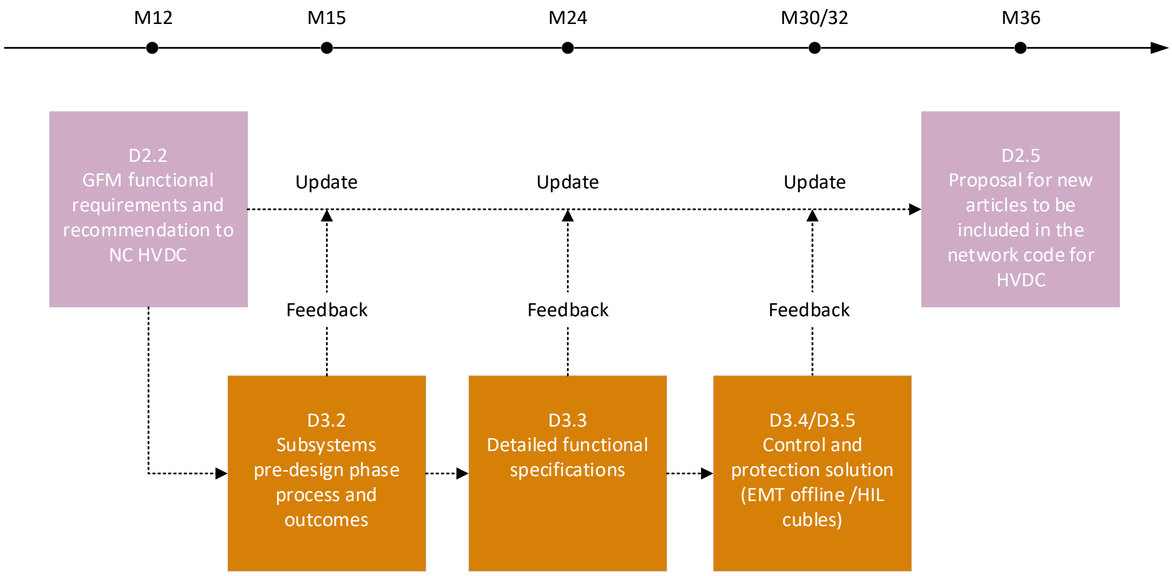

Figure 11. Feedback and iteration between GFM functional requirements from WP2 and the learning process of developing detailed specifications and control and protection solutions in WP3.

6 Chapter 6: Recommendations to NC HVDC on GFM control

This chapter summarizes the recommendations of GFM functionality to the European network codes on HVDC systems (NC HVDC). In December 2023, in parallel with InterOPERA Task 2.4, an expert group published a report with NC HVDC amendment suggestions including a new GFM control requirement article (Article 14) [34]. The report from the Expert Group on Connection Requirements for Offshore Systems (EG CROS) [34], has been reviewed and compared against the requirements being proposed in Deliverable D2.2 of InterOPERA.

In general, it can be stated that the content of the proposed Article 14 (Grid forming capability) in the EG CROS report aligns well with the proposed definition and functionalities elaborated in D2.2 of InterOPERA.

The fundamental similarity is that the GFM requirement is structured around specifying that the GFM converter shall behave as a slow changing voltage source behind an impedance within the current, voltage and energy limits of the GFM converter. Minor differences exist, for example the EG CROS suggests to use the terminology *natural* with respect to the GFM response, whereas D2.2 defines it as *inherent*.

With regards to definitions and terminology, the EG CROS Article 14 specifies several of the requirements directed to the *HVDC system*[11], and some requirements directed to the HVDC converter station. However, within InterOPERA all requirements are specified not on a system level, but on a sub-system level, being synchronous connected HVDC converter stations, remote-end HVDC converter stations and DC connected PPMs.

Table 11 show a comparison between the EG CROS proposed Article 14 and the GFM requirements proposed in InterOPERA D2.2. Several requirements can be directly mirrored between the documents, although differences in wording and terminology exist.

An example is that the EG CROS specifies in its Paragraph 2 of Article 14, that the HVDC converter shall have the capability to transfer to and from an island mode of operation in a continuous manner. This is a very similar requirement to the self-synchronization capability specified in D2.2.

Although similar in definitions and structure, it is recommended that the NC HVDC amendment can be expanded with additional functionalities proposed in InterOPERA D2.2.

Most evident are the requirements that are aimed at ensuring DC voltage control and stability coordination when HVDC converters are required to be in GFM control. An important requirement is the requirement of HVDC converter stations to have simultaneous activation of GFM control and Vdc droop control.

[11] NC HVDC and EG CROS: HVDC system means an electrical power system which transfers energy in the form of high voltage direct current between two or more Alternating Current (AC) buses and comprises at least two HVDC converter stations with DC transmission lines or cables between the HVDC converter stations.

Another aspect that can be considered is the deeper detailing of the voltage source behind an impedance behaviour with the sub-division into self-synchronization, phase jump power, inertial active power, inherent reactive power and positive damping power in order to be able to unify and exhaust performance criteria to each functionality individually which should be considered.

Some requirements proposed in Section 5.1 are considered novel and the feasibility of these requirement must be investigated and demonstrated as part of InterOPERA WP3 as described in Section 5.2 before they are adopted in the NC HVDC. Specifically, requirement C.3 and C.4 with respect to limitation of GFM control as a function of the DC voltage operational ranges.

In summary, it is recommended that that the NC HVDC amendment process considers the InterOPERA GFM functional requirements listed in Section 5.1 to prepare the GFM requirements in the NC HVDC for multi-terminal multi-vendor application with GFM support from DC connected PPMs. This involves consideration of addressing the similarities and differences highlighted in Table 11.

Table 11. Comparison between EG CROS proposed GFM Article 14 [34] and InterOPERA D2.2 functional requirements in Section 5.1.

	EG CROS proposed Article 14	InterOPERA D2.2 GFM requirements
Voltage source behind an impedance within voltage, current and energy limits	Paragraph 1	Requirement A.1, A.2, A.3
Behaviour when limits are reached	Paragraph 1.c.iv	A.3
GFM functionality in the full active power range within voltage, current and energy limits	Paragraph 3	A.2
Specifying dynamic performance requirements	Paragraph 4	A.8
Specifying withstand requirements	Not specified under Article 14 (GFM) as it follows the universal requirements in NC HVDC	Requirement Group B, aligned with NC HVDC and EG CROS but phase jump withstand and RoCoF withstand highlighted explicitly due to its close relation to GFM control.
Self-synchronization / Island mode / standalone operation	Paragraph 2	Requirement Group E and Requirement D.3 for DC connected PPMs.
Phase jump power	Paragraph 1.b.i (Not explicitly specified, but included implicitly)	Requirement Group F
Inertial power	Paragraph 5	Requirement Group G
Inherent reactive power	Paragraph 1.b.i (Not explicitly specified, but included implicitly)	Requirement Group H
Positive damping power	Not specified, but damped response is mentioned related to inertia in Paragraph 5.	Requirement Group I

Frequency response based on measurement of RoCoF	Paragraph 6 (if GFM control is not requested)	Not specified as this is not considered a GFM functionality, which is also the pre-condition in Paragraph 6 of EG CROS Article 14.
DC-connection point requirements of GFM control for HVDC converters and coordination between DC voltage control and GFM control	Not specified	Requirement Group C. However, adaptation of C.3 and C.4 should be considered based on the conclusions of WP3 of InterOPERA with respect to the feasibility of the requirements.
Requirement of simultaneous activation of GFM control and Vdc droop control for HVDC converters	Not specified	Requirement C.2
Parallel operation of remote-end HVDC converters and DC-connected PPMs	Not explicitly specified, but may be indirectly covered in the new definition of the isolated AC system and supporting requirements	Requirement A.11

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8 Appendix 1: Literature review

8.1 ENTSO-E: High Penetration of Power Electronic Interfaced Power Sources (PEIPS) and the Potential Contribution of Grid Forming Converters [1]

8.1.1 Summary

In this detailed publication [1], general concerns, motivations, functionalities, and definitions for Grid Forming are well captured. The document is extensive and also links to multiple relevant references.

Stability issues are categorized by frequency, voltage, rotor angle, converter driven and resonance stability.
The following stability challenges are listed (section 1.2), in line with the ones identified in project MIGRATE:

1. Reduction of Total System Inertia (TSI)
2. System split.
3. Lower short-circuit power levels
4. Rotor angle stability
   (new power oscillations and/or reduced damping; reduction of transient stability margins)
5. Voltage stability
   (deficient/excess reactive power sources; altered static and dynamic voltage dependence of loads)
6. Instabilities relating to fast dynamics of power converters
   (resonance due to cables, interaction between converters and with passive AC components)

As an example, EirGrid states it will need GFM type performance to retain stability for operation beyond 70% penetration of non-synchronous generation and moving its penetration capability from 70 to 95% is deemed necessary to allow a three-fold increase in wind capacity and some level of PV.

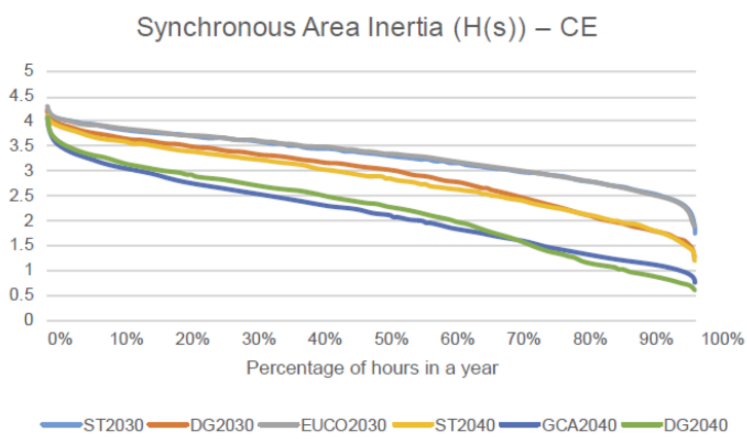


Figure 12. Synchronous Area Inertia [1]

Seven capabilities are introduced, which are termed as grid-forming if fulfilled in their entirety:

1. Creating (forming) system voltage
2. Contributing to fault level (short circuit power)
3. Contributing to total system inertia (limited by energy storage capacity and the available power rating)
4. Supporting system survival to allow effective operation of low frequency demand disconnection
5. Acting as a sink to counter any unbalance in system voltage
6. Acting as a sink to counter harmonics and inter-harmonics in system voltage
7. Preventing adverse control system interactions

It is the Class 3 PPMs that, beyond resilient operation, shall be capable of supporting the operation of the AC power system without the need to rely on synchronous generators. This class may in the future provide the above functionalities.

It is stated that these features are limited by boundaries of defined capabilities (such as short-term current carrying capacity and stored energy). Transient change to defensive converter control strategy is allowed (if it is not possible to defend the boundaries), but immediate return is required.

There is a risk associated with treating the challenges individually, as a positive contribution to one aspect may be detrimental to another. An example of this is that a pure form of synthetic inertia may be detrimental to control interactions by making these worse rather than better and has therefore not been adopted.

8.1.2 Key take-aways

Requirements for Grid Forming PEIPS are discussed in section 2.2 of the ENTSO-E document. The key remarks are summarized below in few words and in relation to the above listed capabilities:

- Create system voltage
  Definition from draft Grid Code: voltage source behind a reactance between 5Hz-1kHz
  Generally not applicable to single-phase
  Possible qualifying criteria:
  - supply linear and non-linear loads (specify THD_U at given THD_I)
  - transient active/reactive power from load steps can be fulfilled
  - capability to withstand large voltage angle changes

- Contribute to fault level
  Limited to the converter's current capacity.
  Exceeding the current limits is prohibited by modifying the voltage angle or magnitude.
  Question: should current be proportionally scaled or should active or reactive power be prioritized?

- Sink for harmonics
  Power quality is more of a concern in steady state.
  This feature should receive **lower priority** than dynamic aspects (FRT, frequency support).
  Behavior should be inductive (+ resistive for damping) limited to a set frequency (eg 2kHz).
  Proportional sharing of harmonics damping between many units is both necessary and desirable.

- Sink for unbalances
  Similar to harmonics. Also, lower priority.
  NPS and PPS current should have a similar contribution, therefore same impedance

- Contribution to inertia
  Emulating synchronous machines is familiar (time constant H) but has underdamped behavior.
  A higher level of damping reduces oscillations but also affects the rate of change of power.
  In the future it may be possible to vary the inertial and damping gains based on varying grid characteristics. Whether this would be beneficial or not is still an open question.
  GFM may still be beneficial with reduced current and energy capabilities.
  ENTSO-E memorandum 'Minimum required inertia for Continental Europe' not turned into final value.

- Prevent adverse control interaction
  One view: "a general specification, which avoids control interaction and resulting harmonic over-voltages in any situations', might be very conservative and impossible to fulfil"
  A contrary view: a Thevenin source behind an impedance with bandwidth limitation (5 Hz – 1 kHz)
  Discusses study and validation methodologies (impedance scan, RMS/EMT simulation, SiL, HiL)

It is highlighted that imposing requirements at the generator level with Network Codes guarantees the availability of functionality associated to primary control, even if market or coordinating mechanisms malfunction in critical situations, providing better system security, especially during large disturbances.

8.1.3 Discussion

Implication of GFM is assessed in sections 2.3-2.4 of the ENTSO-E document, namely for wind power plants (WPP) and HVDC installations.

WPP are subject to rigorous certification procedures and are faced with customer expectations of very high availability, reliability, and high lifetime. As a result, development costs are significant.

WPP are designed to be cost-efficient and have no significant internal storage. The mechanical drive train may be subject to strict limitations of load dynamics and may not be adequate as a storage element. When operating with maximum power point tracking, any power perturbations will also deviate the generator from its optimal point and into a subsequent "recovery period" leading to reduced overall power generation. Additional energy storage may be necessary for WPPs, which will have direct capital cost implications.

If a power reserve margin (operating below the maximum power point) is used, this is also directly detrimental to feed-in revenue and levelized cost of energy. Using this power margin could be reserved to times when PEIPS penetration is high (>70%), as system stability is exposed and market value of RE production is low.

For HVDC terminals also, only marginal energy for around one cycle can be drawn from DC capacitance. Increasing the DC capacitance in HVDC valves is very challenging due to the already very high currents. HVDC connecting different synchronous areas offer significant advantages, since inertial contribution can be shared.

Outstanding questions, from section 4:

- How can unintended islanding be avoided?
- Minimum stored energy for GFM?
- Additional current rating required for GFM?
- Useful and/or practical to have GFM only on request?

8.2 EU Connection Network Code Amendments on (RoCoF and Grid Forming) & Stability Management [2]

Summary

Presentation of the workshops on the amendments for Connection Network codes [2]. Here mainly focusing on the RfG but also referring to HVDC codes in the future. Describing requirements for PPMs of type A, B, C & D in form of mandatory, non-mandatory and non-exhaustive requirements often connected with a transition period for implementation.

Key take-aways

Requirements for Type-A PPM are mainly described here. It has to be checked if those requirements could also be seen as future GFM requirements for HVDC, as Type-A Grid Forming requirements will be the only non-mandatory ones in the future.

The relevant TSO shall have the right to request grid forming capability from type A PPM at its connection point as defined by the following paragraphs:

a. Within the power park module current limits, the power park module shall be capable of behaving at its connection point as a voltage source behind an internal impedance (Thevenin source), during the normal operating conditions (non-disturbed grid conditions) and quasi immediately after a grid disturbance (including voltage, frequency, and voltage phase angle disturbance). The Thevenin source is characterized by its voltage amplitude, voltage phase angle, frequency, and internal impedance.

b. During the first instant following a grid disturbance and while the power park module capabilities and current limits are not exceeded:

(i) the instantaneous AC voltage characteristics of the Thevenin source according to paragraph (a) shall be capable of not changing its amplitude and voltage phase angle while voltage phase angle steps or voltage magnitude steps (in positive and in negative sequence) are occurring at the connection point (grid side). The positive and the negative sequence current exchanged between the power park module (power park module side) at the connection and AC grid shall flow naturally according to grid and converter impedances.

(ii) The relevant system operator shall specify a minimum time dependent current profile for which the grid forming capability of the power park module is required.

c. During the disturbance period (voltage magnitude, frequency, and voltage phase angle disturbance) and after the first instant,

(i) The internal voltage magnitude and voltage phase angle of the power park module shall be adapted according to a predefined dynamic performance.

(ii) The power park module active and reactive current adjustment shall always respect the minimum and maximum power park module capability and current limits.

(iii) The TSO may specify additional requirements in the case that current limitation is necessary.

(iv) The power park module shall be capable of stable and seamless transition when reaching the power park module current limits, without interruption, in a continuous manner and returning to the behavior described in paragraph (b)(ii) as soon as the limitations are no more active.

d. The required energy to deliver the minimum capability in paragraph (a) to (b) shall be ensured through the whole active power operating range of power park module.

e. The required dynamic performance of the power park module for the paragraphs (a) to (d) and its associated performance parameters shall be specified by the relevant TSO.

Second section of the document addresses the RoCoF withstand capability which concerns the HVDC as well.

Causes of Frequency Change (FC) for small and high RoCoF is discussed. The large RoCoF are caused by system splits, and this is the target for requirement definition. Occurrence of these events are studied for the future according to "ENTSO-E, 'Frequency Stability in Long Term Scenarios and relevant Requirements', 3 December 2021" and that suggests in future the risk remains. The Christoph Strunk et al. "Correlation between global and local RoCoFs and their relevance for robustness requirements of generation units" WIW 5 September 2022 suggests an indicator of 1 Hz/s as a limit for split system as a design concept, while for interconnected system the RoCoF requirement definition and relaxing the RoCoF constraints.

Then ENTSOE proposal suggests in Article 13.1 - b:

- A power-generating module shall be capable of staying connected to the network and operate at rates of change of frequency up to the following values:
    - ±4,0 Hz/s over a period of 0,25 s
    - ±2,0 Hz/s over a period of 0,5 s
    - ±1,5 Hz/s over a period of 1 s
    - ±1,25 Hz/s over a period of 2 s
- Power-generating module shall be capable of staying connected to the network and operate at the sequence of rates of change of frequencies according to the following figures, which states to accept the Frequency against time profile as acceptance criterion.
- If rate-of-change-of-frequency (RoCoF) is used for protection when connection to the main grid is lost (Islanding mode), the rate-of-change of frequency threshold shall be set at a higher value.
- The power-generating module shall be capable of remaining connected to the network and continuing to operate stably when the network frequency remains within the frequency range specified in Table 2. The protection schemes shall not jeopardize frequency-ride-through performance specified in Art. 13.2.b.

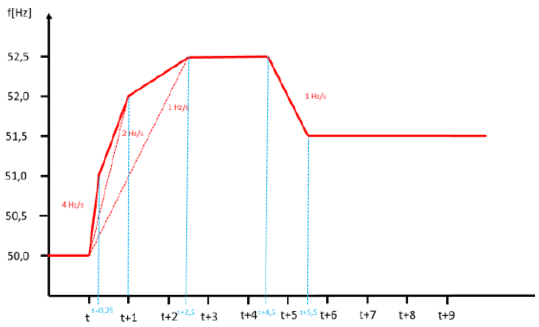


Figure 13. Overfrequency against time profiles [2]

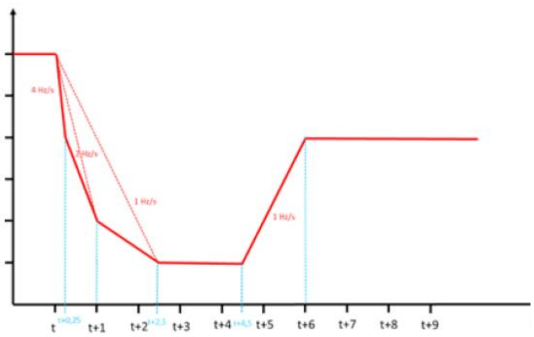


Figure 14. Underfrequency against time profiles [2]

Discussion

Ongoing process: to be updated in the next weeks/months. To be checked which requirement are really planned to apply for HVDC.

Relevant functionalities (to InterOPERA), -- although very generic -- by this requirement:

PPM grid following:

- Proper behavior of the PLL and the control, not leading to instability

PPM grid forming:

- Stability of control
- No loss of synchronism

8.3 FNN Guideline: Grid forming behavior of HVDC systems and DC-connected PPMs [3]

Summary

The FNN guideline [3] is a supplement to VDE-AR-N 4131 that aims at defining methods for verifying the two specific new requirements, i.e., the dynamic frequency/active power behavior and the dynamic voltage control without reactive current specification. The document first gives high-level generic requirements for stable system operation, design parameters for grid forming converters, and guidelines for application of grid forming including possible restrictions. The guideline continues to describe the interface between system operator and network connection owner in the procedure of verifying grid forming behavior. Lastly, methods are presented for system operators to define envelopes (upper and lower limits) around a reference behavior for the grid forming system's response to triggered events, based on given scenarios, to be used as benchmarks for the simulated behavior of the actual system. The guideline outlines test networks, test scenarios and methods for specifying the reference behavior and the validity range in order to verify the conformity of the GFM behavior. Two methods of generating reference behavior curves and three methods for deriving envelopes from these are presented.

The guideline is not intended to specify GFM control strategies and does not give any guidelines for technical implementation. It also gives an account of some key conditions which are not addressed, such as interaction between HVDC systems with DC-connected PPMs connected through PEIDs, interaction between HVDC systems and DC-connected PPMs of different manufacturers, and optimization of control functions with mutual impacts.

Key take-aways

The document defines generic system-level requirements including:

- Management of a system split with the regard of power imbalance, maximum permissible RoCoF and minimum required inertia,
- limitation of the maximum voltage drop due to grid faults similar to voltage source behind an impedance,
- ensuring controller robustness and stable operation under small and large disturbances, and
- ensuring stable operation of parallel HVDC systems and DC-connected PPMs.

Some key high-level grid forming design parameters mentioned:

- Required active power can only be provided if it is instantly available at the HVDC station.
- The required active power must be supplied by a source that is independent of the connected AC grid:
    - Can be supplied from another independent synchronous area through DC interconnectors, from rotating masses of DC-connected PPMs or from other energy storage systems.
    - HVDC systems have practically no inherent energy reserves in themselves.
- The expected grid-forming response is always meant to respect the converter current and voltage ratings and energy limitations. When the limits are reached, control actions can be carried out and grid forming behavior no longer has a priority.
- HVDC stations have almost no inherent energy reserves.
- Other system requirements such as FRT, damping torsional frequency and harmonics can restrict the grid forming behavior.

The guideline defines the test scenarios to validate the overall performance of GFM:

Scenarios to be examined for HVDC systems	Scenarios to be examined for DC-connected PPMs
▪ Phase angle step of network voltage ▪ Linear frequency change in network voltage with initial phase angle step ▪ Voltage magnitude step in network voltage ▪ Presence of a negative-sequence component in the grid ▪ Presence of harmonics ▪ Presence of subharmonics ▪ Change in the network impedance ▪ Islanding with voltage source under grid forming control ▪ Islanding with 2 DUT with voltage source under grid forming control ▪ Change in the network impedance with 2 parallel DUT	▪ Phase angle step of network voltage ▪ Linear frequency change in network voltage with initial phase angle step ▪ Voltage magnitude step in network voltage ▪ Presence of a negative-sequence component in the grid ▪ Presence of harmonics ▪ Presence of subharmonics ▪ Change in the network impedance ▪ Islanding with voltage source under grid forming control

Figure 15. Test scenarios for validation of GFM performance. [4]

Conformity verification criteria is based on time varying envelopes around the reference time varying curves. The term "undelayed" is used to characterize the instantaneous response of GFM inverters: its response would counteract the grid disturbances in phase, frequency, and amplitude. The impedance-related voltage source (voltage source behind impedance) model can be used to show this "network-stabilizing behavior".

The guideline proposes three methods to define the envelopes from the reference time varying curves. The reference time varying curves are generated with the impedance-related voltage source (non-linear effects are not considered). The TSO decides between the following methods to define the envelopes curves:

1. Time-curve up to the first peak and of the steady state (a tolerance band is defined).
2. Continuous envelope based on the simulation model with actual topology (a delta function is generated).
3. Derived envelopes based on the simulation mode of the impedance-related voltage source.

For the grid-forming behavior, the response up to the first peak is usually the area of interest.

It should be noted that this document clearly states that interaction between converters from different vendors have not been considered or investigated.

Discussion

- It is positive that a specific method of verifying compliance with requirements to grid forming is proposed.
- The methods seem reasonably simple to apply for a TSO in developing GF requirements.
- FNN guideline method makes for too strict requirements for suppliers, unknown parameters used by customer to generate the reference curves. It must be very clear to the supplier how the reference curves are generated (including all details of the models used and mathematical equations).
- The difference between the actual controller of the converter and the one used to generate the reference curve can be much greater than what the envelope is considering.
- Method for defining envelope curves is based on mathematical functions with arbitrary percentages, without physical meaning and not specific to each scenario.
- The proposed methods does not consider the practical limitations of an HVDC station such as energy limitations.

8.4 CIGRE SC B4: A transparent process to ensure appropriate and compliant grid-forming behavior for HVDC systems and FACTS – A TSO perspective [4]

Summary

The document [4] is based on verification procedure provided by the FNN guideline and discusses the test cases used to assess the dynamic performances of grid-forming controls. The paper also describes a sequence of actions of system operators and manufacturers to reach an accepted grid-forming response and the lesson learnt from initial phase of several grid-forming projects in Germany.

Key take-aways

- A sequence diagram of an application of the FNN guideline and a protentional order of actions is suggested. During the tender phase, the TSO provides a reference behavior based on a generic system design. Envelope curves are also created. The converter manufacturers compile their initial design and highlight the achieved system behavior. The agreed acceptance criteria should later be applied during the project execution phase.

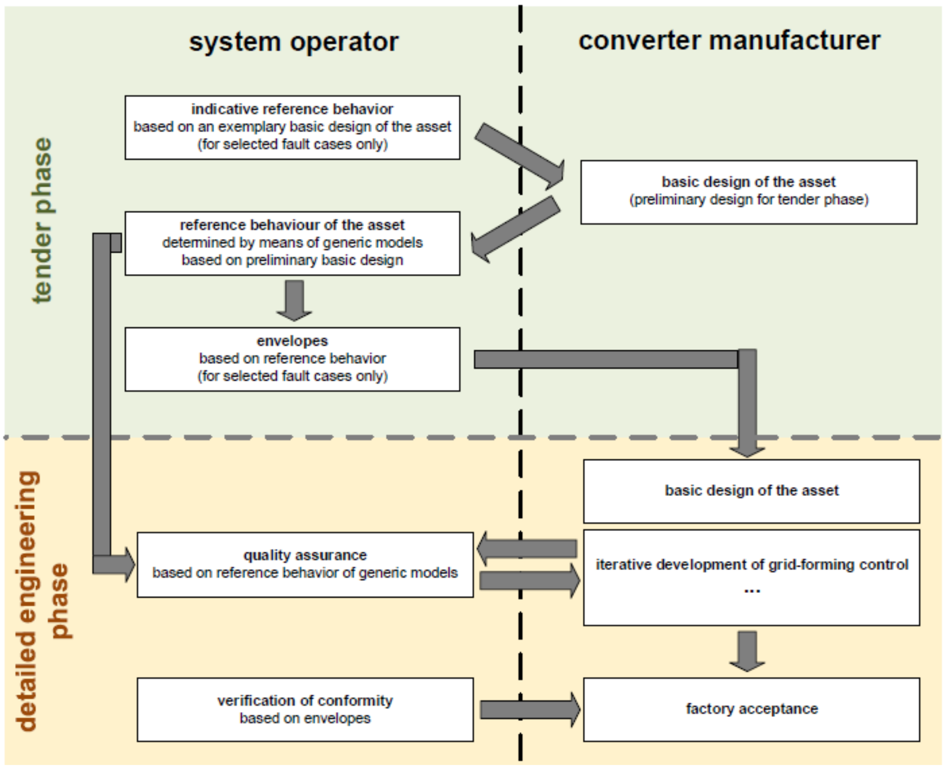


Figure 16. Sequence diagram of an application of the FNN guideline [4]

- The paper articulates the importance of using standardized calculation methods for the assessment of electrical quantities at the POC such as active and reactive power calculations in order to evaluate the GFM controls. An example of calculation method is provided in IEC 61400-21-1. The quantity assessment at the POC should be specified as accurate as possible. The authors suggest that the TSO provides a DLL file containing a component to measure and assess the electrical characteristics at the POC that will be used by all bidders for EMT simulations.
- The authors suggest creating envelope curves only for specific test scenarios and only for the quantity of interest (e.g., active power during phase jumps) and to determine each envelope curve based on signal and test specific design aspects. Example: for a symmetrical fault the reference behavior of GFM is obtained and an envelope curve is created only for the reactive current in positive sequence.

Discussion

- From a technical perspective, this document does not add anything particular to the FNN guideline.

- The main point is the sequence of actions between TSO and venders for applying the FNN guideline, in which it is shown that there should be an iterative procedure between the TSO and the vendors to reach agreements on the envelope curves.
- As the envelope curves are created using generic system design models, they do not include all the limitations of the real system. The acceptance criteria should thus agreed upon based on detailed studies considering all limitations.

8.5 German TSO Paper on Requirements for Grid-Forming Converters [5]

Summary

Joined German TSO Paper on Requirements for Grid-Forming Converters [5]. Translation of the 7 requirements for GFM from ENTSO-E in a non-exhaustive and partly non-obligatory way for the German national grid.

Key take-aways

Mandatory capabilities of grid-forming converters:

- Creating system voltage analogous to the rotor voltage of synchronous generators (voltage source behind an impedance)
- Instantaneous short-circuit current contribution (short-time range behavior)
- Provision of electrical inertia
- Preventing adverse control interaction
- Controller stability (based on operation in a virtual island)

Other characteristics of grid-forming converters that can be demanded:

- Limiting the contribution to harmonics (Sink for harmonics, especially for the 5^{th}, 7^{th}, 11^{th}, and 13^{th})
- Regulation of the negative sequence (Sink for unbalance)
- Provision of additional electrical inertia (energy reserve) by means of extended energy reserve

Optional features of grid forming inverters

- Black-start capabilities for grid-forming converters

Discussion

Paper refers to the 7 Grid Forming abilities mention in this ENTSO-E paper:

High Penetration of Power Electronic Interfaced Power Sources and the Potential Contribution of Grid Forming Converters Link

1. Creating system voltage
2. Contributing to fault level
3. Sink for harmonics
4. Sink for unbalance
5. Contribution to inertia
6. System survival to allow effective operation of Low Frequency Demand Disconnection (LFDD)
7. Preventing adverse control interactions

Here 9 Requirements are named in the German TSO Paper. 5 of them are mandatory, 3 could be demanded and 1 is considered optional. This is a first distinction from the ENTSO-E grid forming topics as prioritization in form of mandatory and non-mandatory requirements.

From the 5 mandatory one the first 4 refer directly to requirements in the ENTSO-E paper while the last one (Controller Stability) doesn't seem to refer to any specific point there. In addition, point 6. Of the ENTSO-E paper didn't seem to be directly addressed in the 4TSO paper.

Of the 3 that could be demanded all of them refer at least partly to one of the 7 requirements from the ENTSO-E paper.

The optional one is not given in the ENTSO-E paper.

As the 5 mandatory requirements are non-exhaustive and are already aligned within 4 TSO this could be one basis to draft common requirements from as a minimum basis. It has to be clarified if the ones which can be demanded, and the one optional ability could also be considered as grid forming requirement of multi-vendor hubs.

8.6 Equinor: An overview of challenges and required functionality with grid forming inverters [6]

Summary

The document [6] is a PowerPoint presentation made by Equinor listing the ENTSO-E seven topics, or challenges, related to grid forming inverters with some elaboration, discussion, and definition of requirements for each of them. The topics mentioned are:

(1) creating system voltage,
(2) contribution to [AC] fault level,
(3) contribution to inertia,
(4) system survival to allow effective load frequency demand disconnection (LFDD),
(5) sink for harmonics,
(6) unbalance and
(7) prevention of adverse control interactions.

Out of these, topics 3 and 7 are given the most focus.

It is assumed that the elaboration on each topic is based Equinor's experience from the Johan Sverdrup field where two HVDC systems from two different vendors (Siemens and Hitachi) operate in parallel as illustrated in Figure 17. The systems are +/-80 kV symmetrical monopoles with ratings of 200 MW and 100 MW respectively. The system is a 'one direction system' from shore to offshore. The Offshore system is an islanded system where the power transmitted from shore via subsea cables is fully dependent on the offshore load.

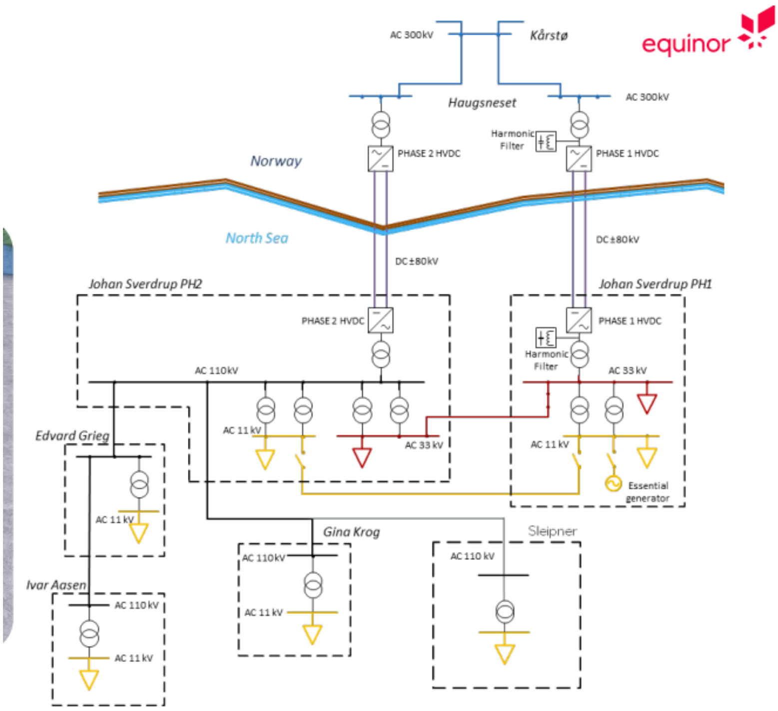


Figure 17. *Johan-Sverdrup grid topology [6]*

Key take-aways

The document considers a system in island-operation where stationary (load-flow) condition is driven by loads and aggregated current-/power-controlled converters based on the capability limits**. It argues that inherent (intrinsic) response of the converters is preferred over using external setpoints (centralized) as control strategy**. Fast reaction has the highest priority, giving preference to a single converter GFM function over a coordinated one.

The seven challenges mentioned can be interpreted as required services from a grid forming converter but are not considered to fall under the definition of functional requirements for grid forming. The following key points are considered as most relevant:

- The converter should behave like Thevenin source and impedance (voltage source behind impedance) regardless of technical implementation.
- Within the capability of the source, the voltage shall be maintained in amplitude, frequency, and phase angle independent from a load connected to the source.
- Inertial response from synchronous machines (SM) are characterized by gain and damping factors (H and D) and comprise of two responses: $P \propto \Delta\delta$ and $P \propto \Delta f$. For converters, a common "language" independent from mechanical characteristics of SMs is needed.
- Fast individual response of the inverters is preferred over a coordinated response.
- Energy for inertial response may be taken from rotating mechanical structures, headroom created for PV, or energy storage system (not implemented).
- During disturbances, frequency support should be prioritized above power quality services like harmonic dampening.
- To prevent adverse control interactions, a frequency bandwidth limitation over which the GFM controls should exhibit a Thevenin source behind an impedance behavior is advocated, to ensure stability for varying network impedance and short-circuit level. A 5 Hz – 1 kHz range is suggested.

- The presentation states that, based on studies, a spatial distribution of GF converters along the power system area is needed for large systems.

Discussion

The document seems to be generic, consists mainly of keynotes and is somewhat unsystematic in its approach when read as a standalone document (which is probably not the intention of the author), hence it is hard to grasp the full meaning by only reading the slides and some assumptions must be made.

The variety of challenges indicates that the authors are addressing converters with grid forming capabilities generally, and not grid forming functionality specifically. Some aspects will also be relevant for grid following converters. This is something that should be discussed in the working group. The key takeaways are based on an early assessment of which aspects are relevant for further work with grid forming in this task.

The presentation is much in line with other literature in this study, with maybe a few additional points that should be considered. Prioritizing frequency support above harmonic dampening (power quality services) is mentioned specifically. In general, with many requirements to grid services, a hierarchy must be defined for services that cannot be simultaneous. This hierarchy will be different for the different operating states of the DC grid (e.g., steady state, disturbance, etc.). Placing frequency support, or "inertial response", in this hierarchy is outside the scope of InterOPERA T2.4 but this fact still may be useful to keep in mind when defining grid-forming behavior in this task. Classification of GF services is an important fact which helps us to prioritize them based on likelihood of occurrence and/or on severity of consequences. Not all the cases make sense to be investigated in detail.

8.7 Minimum Specification Required for Provision of GB Grid Forming (GBGF-I) Capability [7]

Summary

National Grid co-developed the minimum specification for grid-forming, called GBGF-I, together with several market stakeholders [7]. The GBGF-I focuses on emulating the behavior of synchronous generators in power electronic based applications.

Key take-aways

- "*The basic structure of the Grid Forming Plant shall comprise an internal voltage source and impedance. The impedance would be real being made up of either one or a string of real impedances between the internal voltage source and connection point and would not comprise virtual impedances*".
- Grid Forming Plant is required to remain in synchronism and withstand a voltage angle change of 60 degrees. The 60 deg. withstand level is still under review [8].
- When subject to a fault or disturbance, or System Frequency change, each Grid Forming Plant shall be capable of supplying Active Inertia Power, Active Phase Jump Power, Active Damping Power, Active Control Based Power, Control Based Reactive Power, Voltage Jump Reactive Power and GBGF Fast Fault Current Injection.

- Providing a symmetrical ability for importing and exporting Active ROCOF Response Power, Active Phase Jump Power, Active Damping Power, and Active Control Based Power under both rising and falling System Frequency conditions.
- Being designed so as not to cause any undue interactions which could cause damage to the Total System or other User's Plant and Apparatus
- Include an Active Control Based Power part of the control system that can respond to changes in the Grid Forming Plant or external signals from the Total System available at the Grid Entry Point or User System Entry Point but with a bandwidth below 5 Hz to avoid AC System resonance problems.
- GBGF-I with an importing capability mode of operation such as DC Converters, HVDC Systems and Electricity Storage Modules are required to have a predefined frequency response operating characteristic over the full import and export range which is contained within the envelope defined by the red and blue lines shown in Figure ECC.6.3.19.3.
- Each User or Non-CUSC Party shall design their GBGF-I system with an equivalent Damping Factor of between 0.2 and 5.0. It is down to the User or Non-CUSC Party to determine the Damping Factor, whose value shall be agreed with The Company.
- Each GBGF-I shall be designed so as not to interact and affect the operation, performance, safety or capability of other User's Plant and Apparatus connected to the Total System. To achieve this requirement, each User and Non-CUSC Party shall be required to submit the data required in PC.A.5.8
- The following tests are required to prove compliance of GBGF-I:
    - RoCoF or frequency ramp test
    - Phase jump test: both small and large phase jump (up to 50 deg.) at an agreed loading point or different loading points
    - Fault ride-through and fast fault current injection
    - 3 phase-to-ground faults followed by Islanding with passive load
    - Network frequency perturbation (NFP) plot
- Additional energy storage on the AC side of onshore converter for phase jump power was discussed. The goal is to keep using the existing & proven HVDC and offshore wind farm technologies.
- Phase jump power response within 5 ms and can have frequency components above 1 kHz.

Discussion

The requirements above are still under review by GBGF-I "Best Practice Guide" Group. For example, an extensive discussion was made around the use of virtual impedance and its pros and cons. One obvious benefit for virtual impedance is that it can help in limiting transients during severe events such as large voltage angle changes when the grid is strong. It's to be noted the equivalent reactance X of HVDC converter including transformer (typically < 0.3 pu) is lower than synchronous machine reactance including its step-up transformer. Moreover, the transient current capability of converter is smaller than a synchronous generator. Thus, the converter stability may be jeopardized due to overload or inability to control internal DC voltage during a large disturbance e.g., large AC voltage phase jump (up to 60 deg. in this case). To guarantee stability, a costly upsizing may be required if the use of virtual impedance is not permitted. The virtual impedance may also be beneficial in improving the grid stability by damping dc and low frequency oscillations. This can be important as, depending on the design, grid forming control can be prone to instability when grid is strong [23]-[24].

"*The objective of grid forming IBRs should not be simply to reproduce the behavior of synchronous machines. Instead, the focus should be on understanding the needs of the evolving power grid and utilizing the IBRs in the most effective way*"

- Voltage source behind an impedance: Limiting the design to only allow real impedances, and no virtual impedance emulation seems too restrictive
- Generally, the definitions seem to dictate the control solutions too much in the direction of specific VSM implementations compared to what is desirable in the context of InterOPERA. In InterOPERA we do not desire to direct or limit the vendors to specific control solutions.
- The document proposes certain quantities, such as 5 ms time delay allowed. This can be seen as an inspiration and similar quantities needs to be specified within InterOPERA. However, the way active & reactive power is measured is important when quantifying the delay.
- The terminology used for power responses are new, and should be carefully considered before adaptation (e.g., Active Inertia Power and Active Phase Jump Power)
- The use of time-scales to define the required behavior is useful and provides an easy way of understanding.
- A realistic phase jump withstand limit needs to specified. Also, rise time, grid strength and operating point are important to be known when preforming compliance test for phase jump.

In the recent Best Practice Guide [8], the use of virtual impedance, current control and PLL are allowed during Normal mode provided that 5 Hz control bandwidth limit is met. In Withstand mode all control functions are allowed and there is no bandwidth limitation.

8.8 Great-Britain Best Practice working group and guide [8]

Summary

This document [8] is a supporting document for the National Grid GBGF-I requirements for grid-forming. The document emphasizes the need for converters to provide the defined *active phase jump power* for maximum active power transient disturbance as specified by the system operator, as the most important grid-forming requirement. The document proposes four specific updates to the National Grid grid-code:

1. **Maximum AC Power Transient**. = 2 GW.
2. **Maximum Operational Design Limit** for the **Phase Jump angle** = 20 degrees (minimum 5 degrees) in a local zone of the AC Grid. For this condition the **GBGF- I** inverters will be in their linear mode and not in a current limit.
3. **Maximum Withstand Phase Jump Angle** = 60 degrees in a local zone of the AC Grid.

   This is a rare event that only occurs when a feeder is closed on to the main AC Grid.

   The 60-degree value is the allowed closing difference angle of the associated **ACCB**. For this condition the **GBGF- I** inverter are permitted to operate in a limiting mode that could be the current limit value.
4. **Minimum Change Time** for **the Phase Jump angle** ≤ 5 ms. This is important as it alters the required current limit value of the **GBGF- I** inverters. This value can be interpreted as what it meant by an inherent response.
5. **Active inertia power** and **active damping power** are also requested from GFM converters.

Furthermore, the document discusses whether PLL software is allowed for grid-forming. This is not finally concluded, but the position is that PLL software is only allowed if it provides an additional benefit and not to control the phase of the voltage when operating below the current limitation (e.g. in grid-forming mode). This document also requires a control bandwidth limit of 5 Hz to avoid instability and the production of a continuous output of sub-harmonic frequencies.

Key take-aways

- The concept around defining a "phase jump angle" for maximum power delivery is emphasized. Quantifications are provided.
- With respect to the previous best practices documents, the following changes can be observed:
    - All requirements are expected within the converter limit (no over-sizing mandate).
    - Internal voltage is defined as the Grey Box. Definition and figures as relevant to virtual impedance are recommended to be removed. Advantages of virtual impedance are also pointed out such as provision of damping.
    - The naming of the two operation modes has changed from linear and nonlinear mode to normal and withstand mode.
- The use of PLL software for grid-forming is discussed and is not allowed for voltage control when operating below the current limitation.
- Modelling and simulation methods (EMT, HIL) for verifying the requirements are discussed.

Discussion

The document provides input to the GBGF-I requirements. The document discusses how to emulate the behavior of a synchronous machine for converter-based resources. This is not necessarily the desired strategy for HVDC and multi-terminal HVDC grids. However, the approach is thoroughly described. The restrictions towards the use of PLL software and the avoidance of the use of a virtual impedance is too restrictive.

Moreover, some of the requirements in this document will mandate a special control implementation strategy for GFM control, which should not be dictated to manufacturers.

8.9 OSMOSE: Analysis of the synchronization capabilities of BESS power converters [9]

Summary

This document [9] analyzes the synchronization capabilities of battery energy storage system (BESS) power converters for grid-forming services. It was created as part of the OSMOSE project, which is focused on developing innovative energy storage solutions for a sustainable power system.

It discusses the definition of grid-forming, its key features and requirements, and how to formulate functional requirements for grid-forming. The document also compares grid-forming services with other grid services, such as fast frequency response (FFR), that can be delivered by grid-following converters. Finally, it explores the practical implications and hardware requirements of grid-forming.

Key Takeaways

Grid-forming services are defined different from other grid services, such as FFR, that can be delivered by grid-following converters because grid-forming actively controls the voltage and frequency of the grid, while FFR only provides a fast response to changes in frequency.

The functional requirements for grid-forming include stability and robustness, as well as the ability to respond to changes in the grid and to operate in various modes of operation. These requirements can be quantified using performance metrics such as steady-state voltage regulation error, transient response time, and dynamic stability margin.

The hardware requirements for grid-forming include high-bandwidth control systems, energy storage systems, and low impedance connections to the grid. These requirements can be quantified using performance metrics such as bandwidth, power capacity, and fault ride-through capability.

The report also highlights the practical implications of implementing grid-forming converters, including the need for specialized hardware and control systems.

Section 3.2 of the report, the technical specifications required for a grid-forming converter are detailed. These specifications include:

- Standalone capability
- Synchronizing active power
- Inertial response
- System strength
- Fault current

Discussion

This document provides a detailed analysis of grid-forming services and their practical implications for BESS power converters. It highlights the importance of grid-forming for the reliable operation of isolated or weak grids and identifies the key features and requirements of grid-forming. The document also compares grid-forming services with other grid services, such as FFR, that can be delivered by grid-following converters and shows that grid-forming is a distinct and important service that requires specific functional and hardware requirements.

The discussion of functional requirements for grid-forming is particularly useful, as it provides specific examples of how these requirements can be formulated and quantified. For example, the document describes how steady-state voltage regulation error can be used to quantify the accuracy of grid-forming and how transient response time can be used to quantify the speed of the response to changes in the grid. The document also describes how dynamic stability margin can be used to quantify the robustness of grid-forming under different operating conditions.

In addition, the document provides specific examples of how grid-forming is different from other grid services, such as FFR. For example, while FFR only provides a fast response to changes in frequency, grid-forming actively controls the voltage and frequency of the grid, which is necessary for the reliable operation of isolated or weak grids. The document also shows that FFR can be delivered by grid-following converters, while grid-forming requires specific functional and hardware requirements that are not necessary for FFR.

8.10 UNIFI: Specifications for Grid-forming Inverter-based Resources [10]

Summary

The report "Specifications for Grid-forming Inverter-based Resources" [10] was formulated by UNIFI Consortium. This is Version 1, which was published in December 2022. It is intended to have updated versions later based on feedback and continued progress on the topic.

UNIFI (**UN**iversal **I**nteroperability for grid-**F**orming **I**nverters) Consortium is a forum to address fundamental challenges in the seamless integration of grid-forming (GFM) inverter-based resources (IBR) into power systems of the future. It started in January 2022 with funding from Department of Energy, USA.

The specifications in the report cover all GFM technology applications including, but not limited to: battery storage, solar photovoltaics (PV), wind turbines, HVDC, STATCOM, UPS, supercapacitors, fuel cells, or other yet to be invented technologies. While each may have different DC side and energy limitations, the specifications focus on the AC side performance requirements as they relate to interoperability between GFM IBRs and the power system.

Key take-aways

The specifications are high-level functional requirements, which describe in a generic way what a GFM IBR is expected to behave under different circumstances. It is qualitative but not quantitative, which means no performance metrics are given in numerical values.

The specifications are divided into 2 groups: universal and additional performance requirements. Universal requirements are to be provided regardless of the type of the GFM resource, the operating condition of the resource, and the strength of the grid to which it is connected. Additional requirements may be implemented in coordination with the power system operator and can vary from site to site.

Universal requirements are further grouped into 2 scenarios: normal and abnormal operational conditions.

The specifications are summarized below in *Table 12*. All relevant capabilities required are considered within the IBR's hardware limits, which means no oversize design is needed/required.

Table 12. UNIFI specification for grid-forming capability

Universal performance requirements	Normal operational conditions	Autonomous support to the grid based on local measurements
		Dispatchability of steady-state power output
		Positive damping to voltage and frequency oscillations
		Power sharing among generation resources
		Robust operation in and improvement to low system strength grids
		Help in reducing the voltage unbalance factor (VUF)
	Abnormal operational conditions	Fault-ride-through
		Maintain a balanced internal voltage in asymmetrical faults
		Frequency response
		Resistance to changes in positive-sequence voltage magnitude and phase angle

		Maintain an intentional islanding operation
Additional performance requirements		Black-start
		Reduce voltage harmonics
		Cyber-secure communications
		Secondary control of voltage and frequency
		Short-term rated current
		Constraints due to DC source

Discussion

This document suggests dividing the GFM requirements into different categories, being normal operation, abnormal operation and then additional requirements that are optional, as they may lead to additional hardware cost. This is similar to other sources that suggest a division of the requirements, which should also be considered in InterOPERA.

8.11 ESIG: Grid-Forming Technology in Energy Systems Integration [11]

Summary

The Energy Systems Integration Group (ESIG), previously known as the Utility Wind Integration Group (UWIG), was established in year 1989 to provide a forum for the critical analysis of wind for utility applications. (non-profit educational organization)

- frequency set locally at each inverter. In the transient time frame, GFM IBRs appear to the grid as voltage sources, as long as the resulting currents remain within inverter current limits and an energy buffer is available.
- Although this work is oriented on BESS GFM, however, the guideline and classification of the problems, requirements and solutions are helpful.
- 4 major categories of requirements for GFM function are introduced:
    - Need related to angle stability and synchronization
    - Need related to frequency regulation
    - Need related to voltage regulation
    - Need related to damping

Key take-aways

A GFM IBR maintains an internal voltage phasor in the transient time frame, with the magnitude and angle. This document bases the GFM study on Battery Energy Storage System. A GFM inverter needs a synchronization mechanism when it has reached its current or energy buffer limits. If it reaches these limits, it will temporarily fall back to GFL operation and will need to track the grid voltage phasor. ESIG provides a comparison quoted here in Table *13* between Grid Following (GFL) vs Grid Forming (GFM).

Table 13. ESIG comparison of Grid-Forming and Grid-Following [11].

INVERTER ATTRIBUTE	GRID-FOLLOWING CONTROL	GRID-FORMING CONTROL
RELIANCE ON GRID VOLTAGE	Relies on well-defined grid voltage, which the control assumes to be tightly regulated by other generators (including GFM inverters and synchronous machines)	Actively maintains internal voltage magnitude and phase angle
DYNAMIC BEHAVIOR	Controls current injected into the grid (appears to the grid as a constant current source in the transient time frame)	Sets voltage magnitude and frequency/phase (appears to the grid as a constant voltage source in the transient time frame)
RELIANCE ON PLL FOR SYNCHRONIZATION	Needs PLL or equivalent fast control for synchronization	Does not need PLL for tight synchronization of current controls, but may use a PLL or other mechanism to synchronize overall plant response with the grid.
ABILITY TO PROVIDE BLACK START	Not usually possible	Can self-start in the absence of network voltage. When designed with sufficient energy buffer and over-current capability, it can also restart the power system under blackout conditions. (Only a limited number of generators on a system need to be black start–capable.)
ABILITY TO OPERATE IN LOW GRID STRENGTH CONDITIONS	Stable operation range can be enhanced with advanced controls, but is still limited to a minimum level of system strength	Stable operation range can be achieved without a minimum system strength requirement, including operation in an electrical island. (GFM IBRs will not, however, help to resolve steady-state voltage stability for long-distance high-power transfer.)
FIELD DEPLOYMENT AND STANDARDS	Has been widely used commercially. Existing standards and standards under development define its behavior and required functionalities well.	Has been deployed in combination with battery storage primarily for isolated applications. Very limited experience exists in interconnected power systems. Existing standards do not yet define its behavior and required functionalities well.

- GFM needs to respond intrinsically based on measurements from converter's control loop.
- For a GFM IBR, the power exported is not fixed directly by a constant reference but is instead a point on a droop characteristic,
- Voltage and angle during disturbance will be kept constant in the transient time frame.
- Various Grid Forming methods for **EMT** and **RMS** domain can be classified as:
    - virtual synchronous machine control (VSM)
    - matching control
    - droop-based control
    - virtual oscillator control

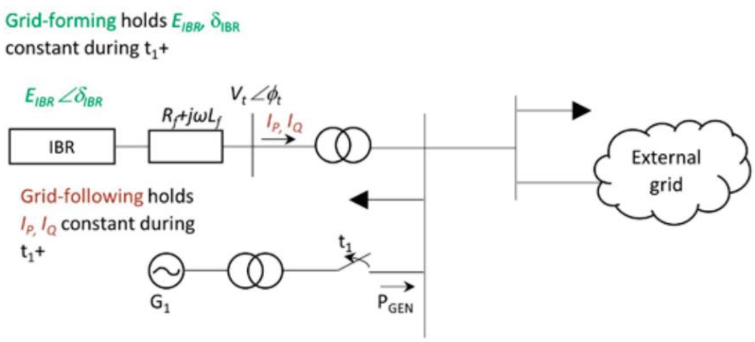


Figure 18. ESIG illustration of Grid-following and Grid-Forming IBR

VSM control is currently the most commonly used in GFM IBR pilots, due primarily to its similarity to the familiar synchronous machine behavior.

Section 3, discusses system needs:

- Generation resources present themselves as voltage sources behind an inductive impedance.
- The synchronization of a generator occurs through variation of power export with angle difference and the accompanying rotor acceleration/deceleration as expressed by the swing equation.
- Imbalances between supply and demand are indicated by changes in overall system frequency. Equivalent source impedance (combining line impedances and generation source impedances) at a node determines grid strength in terms of variation of node voltage with current. Short-circuit ratio (the ratio of three-phase short-circuit apparent power to rated power) is often taken as an indicator of grid strength, since it indicates the amount of equivalent impedance between a strong voltage source and a grid node.
- High-level needs of System Operator are discussed and defined as Synchronization and angle stability, Frequency regulation, Voltage regulation, Damping. Designing services to meet System needs requires mainly:
    - Instantaneous active power response,
    - Fast proportional frequency response,
    - Fast step frequency response

Need Related to Angle Stability and Synchronization	Reason for the Need
Synchronizing torque	Synchronous machines and IBRs must remain synchronized. Loss of synchronization from angle instability can arise in cases of low synchronizing torque. (This is also called synchronizing power.)
PLL compatibility	IBRs' PLLs must remain synchronized with the grid. PLL and control stability support address instability arising from high impedance (low system strength) at an IBR's point of interconnection.
First-swing mitigation*	Synchronization of the grid must be maintained during large voltage disturbances.
Phase-jump mitigation	Synchronization to the grid must be maintained following the abrupt change of voltage angle due to loss of infeed or loss of line.

Figure 19. Angle Stability and Synchronization in the Power System [11]

Need Related to Frequency Regulation	Reason for Need
Regulation	Power fluctuations of generation or load causing drift of frequency need to be mitigated.
Containment within frequency limits	Loss of load/infeed causing a large increase or decrease of frequency to the outside of defined limits and causing equipment malfunction or loss of service needs to be mitigated.
Frequency ride-through	Inability to ride through frequency disturbances leads to tripping of generation and exacerbates frequency regulation problems.
Limitation of RoCoF	Loss of load/infeed causing rapid change of frequency and protection malfunction or unwanted triggering of protection needs to be mitigated.
Settling of frequency	Following a major event, frequency must be immediately contained and stabilized.
Recovery of frequency	Following a major event, after containment and stabilization of frequency, it must be restored in a timely manner.

Figure 20. Frequency Regulation in the Power System [11]

Need Related to Voltage Regulation	Reason for Need
Containment within voltage limits	Heavy line loading and/or absence of reactive power sources leads to voltage excursions outside of limits.
Mitigation of unbalances, harmonics, and flicker	Absence of mitigation (such as low impedance paths to shunt harmonics and unbalances) leads to poor voltage quality.
Voltage collapse mitigation	Sudden and large increase in line loading or grid impedance due to loss of a line causes nonlinear behavior and collapse of voltage beyond bifurcation point.
Voltage ride-through	Inability to ride through voltage disturbances leads to tripping of generation and consequent frequency regulation problems.

Figure 21. Voltage Regulation in the Power System [11]

Need Related to Damping	Reason for Need
Damping of sub-synchronous oscillations	Poorly damped local or inter-area oscillations or amplified resonances can cause instability or equipment damage.
Damping of super-synchronous oscillations and harmonic resonances	Control interactions between IBRs in network conditions with resonant amplification can cause instability in the high frequency range.

Figure 22. Damping in the Power System [11]

Section 4 further discusses the requirements for GFM design and proposes a process for that, and also a market mechanism for such service (out of scope). Some specification and examples are provided from different operators.

There are mentioned 9 points to break the chicken-and-egg cycle to establish technical requirement.

Section 5 suggest a test setup and in general discusses benchmarking GFM functions. This can be a good input for selecting an adequate demo case.

Section 6 provide information about required tools for development, control and testing. For the design and test, the real-time digital simulation tools and Hardware-in-the-Loop are considered as essential requirements.

Discussion

Regarding Grid Forming, this document [11] tries to complete a chain of system needs, services and functions, tools for testing and commissioning and business layer/market scheme. Given that this document is based on BESS-based Grid Forming there are information regarding the principle and methods to be considered. In general, given the full circle of information from grid to function, tool and market mechanism, this can be a valid document to address at least partially the concerns from WP.1 (implementation requirements) and WP.3 (structure of system and business logics).

8.12 IEEE Std. 2800: IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Power Systems [12]

Summary

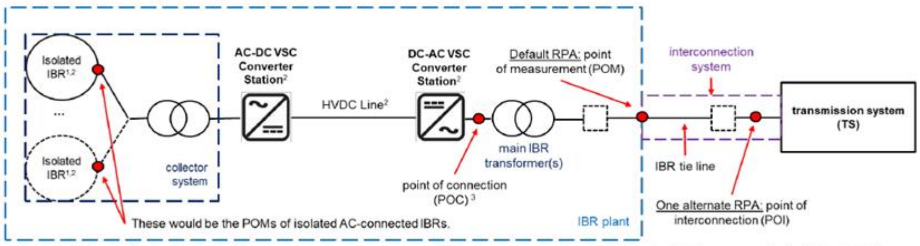
The document describes the standard for voltage and frequency requirements for Inverter Based Resources (IBR) connecting to AC transmission systems (TS).

The document describes the demanded behavior for

- Reactive power-voltage control requirements
- Active power-frequency response requirements
- Response to transmission system abnormal conditions
- Power quality
- Protection
- Modelling data
- Measurement data for performance monitoring and validation
- Test and verification requirements

Especially in chapter 7, important requirements for grid forming capabilities are listed, which are relevant for MV MT HVDC systems.

IEEE Std 2800-2022
IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems



[1] Includes IBR units like type IV wind turbine generators

[2] May serve as a supplemental IBR device that is necessary for the IBR plant with VSC-HVDC to meet the requirements of this standard at the RPA

[3] Depending on design, the POC may be on the TS side of the main IBR transformer.

NOTE 1—This standard applies to isolated *inverter-based resources (IBRs)* interconnected via dedicated voltage source converter (VSC) high-voltage direct current (HVDC) transmission facilities.

NOTE 2—This standard is not intended to apply to voltage source converter high-voltage direct current (VSC-HVDC) connecting two ac interconnections with each other.

NOTE 3—This standard is not intended to specify requirements for VSC-HVDC that connect two buses within a meshed/networked synchronous ac system.

NOTE 4—The requirements for cases where IBR are integrated with a multi-terminal VSC HVDC transmission schemes may be specified by the *TS owner*.

NOTE 5—The requirements for cases where IBR and non-IBR are connected via VSC-HVDC, i.e., hybrid resource facilities, may be specified by the *TS owner*.

Figure 2—Illustration of defined terms for dc-connected isolated inverter-based resources (IBRs)

Figure 23. IEEE std. 2800 - illustration of defined terms for dc-connected isolated inverter-based resources. [12]

Key take-aways

Definitions for Reactive power-voltage control requirements for continuous operation regions containing reactive power capability and voltage reactive control modes in chapter 5. Next to the requirements of chapter 6, where primary and fast frequency responses are described especially for Inverter Based Resources (IBR) like Wind Turbine Generators (WTG),

chapter 7 contains the most important definitions concerning:

- voltage protection requirements
- voltage disturbance ride-through requirements
- voltage phase angle changes ride-through
- frequency disturbance ride-through requirements, subdivided into several regions like
    - Low-frequency (disturbance) ride through
    - High-frequency (disturbance) ride through
    - ROCOF ride-through

Chapter 8, describing limitations to voltage limitations, chapter 9 deals about requirements of protection (frequency -, ROCOF-, AC voltage-, AC overcurrent-, unintentional islanding- and interconnection system protection)

Appendix C4 describes properties of Grid-Forming inverters (converters)

- Grid following control only works well in strong ac power systems, where the IBR injected current only causes small changes at the converter terminal voltage. In weak grids, such an approach can lead to instability in the phase loop locked and the associated controls of the IBR.

- Grid forming is only possible, when there is sufficient energy and power supply inside the IBR, which hast to stabilize the grid at its POC, to stabilize the voltage and avoid voltage steps or jumping of the voltage phasor.

CAUTION: "The objective of grid-forming IBRs should not be simply to reproduce the behavior of synchronous machines. Instead, the focus should be on understanding the needs of the evolving power grid and utilizing the IBRs in the most effective way."

Discussion

This standard is not defining requirements for multi-terminal HVDC systems, rather for single Inverter Based Resource (IBR), but the main objectives of the Appendix C should be considered.

Where is the limit or is there a parameter to describe the grid forming support of an IBR, like dP/S_PoC or dP/S_Poc * dt to describe the impact of the IBR compared to the apparent power at the point of connection.

8.13 IET document: The grid-forming approach [13]

Shakerighadi, B., Johansson, N., Eriksson, R., Mitra, P., Bolzoni, A., Clark A., Nee, H.w-P.: An overview of stability challenges for power-electronic-dominated power systems: The grid-forming approach. IET Gener. Transm. Distrib. 17, 284–306 (2023). https://doi.org/10.1049/gtd2.12430

Summary

This article [13] reviews the technical challenges of GFM-based IBGs seen from TSOs and academic research. Furthermore, it compares the properties of different GFM control methods using the IEEE 9-bus benchmark system via EMT simulations performed in the software PSCAD.

Key take-aways

Main challenges in modern power systems considered by literature review are: the high ROCOF for low inertia systems and inter-area oscillations. GFM converters are seen as a promising solution to boost system stability.

The main solutions applied to GFM control are: modification of the design of the power converters by improving the over- and under-voltage ride-through regulations (FRT capability) and reactive power control, the frequency regulations and active power control, the power-synchronization control by a 1st-order GFM model.

Another discussed solution is to implement inertial-based equipment, such as virtual synchronous generator (VSG) type of GFM converters, leaving SGs in the system as synchronous converters and the application of E-STATCOMs. Four FM control schemes are considered, i.e., power-synchronization control, basic droop control, droop control with additional LPFs and virtual synchronous generator.

The simulation results include a single converter system and the IEEE 9-bus system with multiple GFM converters. Two case studies are performed with the single-converter system, i.e., grid frequency deviation with a fixed ramp and phase jumps at the grid voltage.

In the former case, it is concluded that the reference value for the frequency has to have a very good estimation that follows the grid variations, otherwise the active power capability of the converter may be unable to follow the ROCOF changes. However, this may not be feasible from the design point of view, as the frequency droop control and the inertial response are coupled. A more convenient way to separate the droop control and the inertial response control is to use a measured frequency as the frequency reference or use an HPF to filter out the ramp change in the frequency.

In the latter case study, phase jumps are considered, and it shows the delay in the response of the VSG type of controller, as the back EMF voltage phase will not change instantly because of the active power control loop integrator. Therefore, the back EMF voltage phase lags the grid voltage phase that leads to the active power absorption by the VSC from the grid. As a result, the negative active power continues until the phase angle difference is compensated for by the active power control loop.

For the system studies on the IEEE benchmark, the simulations considered a load change and a line trip.

For the first case, a load increase of 40 MW at Bus 5 is considered. The main results discussed for the VSG control show that the SGs' response to the load increase, and the voltage magnitudes at their output will become oscillatory in the presence of a GFM-based IBG. This oscillation is because of the low damping factor in the VSG model. This is due to the high VSG inertia and its damping factor impacts on the system stability. Increasing the damping factor of the VSG leads to more damped system variables with the cost of more energy consumption from the IBG. Increasing the H value also leads to more energy consumption from the VSG. At the same time, it does not significantly impact the system stability for the load increase scenario.

For the line trip case study, it is assumed that there are two lines in parallel connected between buses 7 and 8. Different VSG contributions can be seen, if the IBG is connected to another bus. It is shown that the VSG acts based on the local frequency. When the VSG is connected to the system within a closer point, it works more like a SG. However, as VSG gets far (like being connected at bus 5), then it works more based on the grid frequency with less contribution.

Discussion

This article shows that it can be tricky to decide what feature of the GFM control must be required/prioritized without knowing the system. For our studies with connected multi-vendor multi-terminal HVDC systems, we can define the most challenging situations and from there, recommend the minimum requirements and study the performance. But how to define these scenarios and minimum requirements within this task? --> Strong collaboration with WP2 and 3.

Also, if in AC systems we locate for example a STATCOM where we may have challenges with voltage stability, how to recognize where and how to locate GFM converters for these different services in HVDC systems?

8.14 IET document: Grid forming inverter and its applications to support system strength [14]

Zhou, Y., Zhang, R., Kathriarachchi, D., Dennis, J., Goyal, S.: Grid forming inverter and its applications to support system strength–A case study. IET Gener. Transm. Distrib. 17, 391–398 (2023). https://doi.org/10.1049/gtd2.12566

Summary

In this paper [14], a GFM with BESS is examined as a solution to strength issues. Its capability to damp sub-synchronous voltage oscillations and to provide inertia are also discussed.

Key take-aways

HIL tests of GFM inverter are performed and the main features of the tested GFM are:

- Control strategy of GFM: virtual synchronous generator
- Possibility to set GFL or GFM control
- Parameters that can be configured: inertia constant, damping coefficient, overload current.

The HIL test demonstrated the GFM capability to actively damp sub-synchronous oscillations of 8 Hz typically caused by control interactions amongst IBRs, SVCs and large network impedance.

The active power response of GFM was tested for different values of the inertia constant: the higher inertia constant improves system stability without any influence in normal operation. The higher the inertia value, the higher the inverter overload capability is required.

A detailed EMT model of the Queensland transmission network was used to verify the GFM effectiveness. The test system is prone to sub-synchronous voltage oscillations and contains buses with low SCL. GFM inverter provides fast voltage control and reactive power support to address voltage instability. The synthetic inertia from GFM helps to limit the frequency and the phase angle changes after a contingency.

Discussion

How should we define the GFM parameters that can be configured (scheduled) by the system operator when specifying connection requirements?

8.15 IET document: Improving grid strength in a wide-area transmission system with grid forming inverters [15]

Mayer, P.F., Gordon, M., Huang, W.-C., Hardt, C.: Improving grid strength in a wide-area transmission system with grid forming inverters. IET Gener. Transm. Distrib. 17, 399–410 (2023). https://doi.org/10.1049/gtd2.12498

Summary

The paper [15] compares the stabilizing contributions of GFM inverters and synchronous condensers considering balanced, unbalanced faults and grid oscillation rejection test. It highlights the limitations of GFM current capabilities. It can be noted that these limitations and the available headroom play an important role in the considerations of application of GFM for system strength services.

Key take-aways

Regarding the reactive current support, the Australian grid-code requires that the in-fault reactive current support must be provided in addition to the pre-fault reactive current levels.

GFM does not:

- Create new modes of instability in a weakly connected network with many GFL inverters,
- Aggravate any of inter-area oscillations,
- Aggravate the weakness of GFL inverters modes.

AEMO has requirements for the grid oscillatory rejection tests.

Oscillatory frequency rejection tests help to confirm the adequacy of GFM tuning.

AEMO has an operational software platform including network generators, compensation devices, transmission lines and loads. This model is used for detailed assessment of IBR connection applications, converter tuning, converter interactions, etc.

A wide-area model is used to compare two solutions: centralized GFM and distributed GFM.

- Distributed GFM inverters: SC are replaced by GFM and some existing GFL connected at weak busses have been expanded with GFM controls.

Both solutions prevented system instability and resulted in very similar post-disturbance behavior. The decentralized solution could offer a more robust solution.

Significant improvement to the stability of a weak system prone to SSCI from GFL inverters can be mitigated via centralized or decentralized GFM reinforcement.

Limitations of GFM associated with their current limitation and oscillatory control characteristics must be considered in the application and evaluation during design, integration, and operation.

Recommendation:

Careful design and control optimization is recommended for virtual synchronous machine based GFMI to ensure the most robust and performance enhancing control when integrated into a system where multiple IBR electrical or conventional machine's electromechanical mode may be present.

Discussion

How can the oscillatory control characteristic of GFM be verified? A small-signal impedance scan across a wide range of frequencies can be used to verify if the inverter contributes positively to the oscillations damping.

8.16 IET document: An adaptive multi-mode switching control strategy to improve the stability of virtual synchronous generator with wide power grid strengths variation [16]

Liu, Z., Qin, L., Zhou, Y., Lei, X., Huangfu, C., Yang, S., Hong, Y., Liu, K.: An adaptive multi-mode switching control strategy to improve the stability of virtual synchronous generator with wide power grid strengths variation. IET Gener. Transm. Distrib. 17, 307– 323 (2023). https://doi.org/10.1049/gtd2.12694

Summary

The paper [16] discusses the idea of switching between two different grid-forming implementations based the grid strength. One implementation uses a PLL and therefore only meant for strong grids and the other one avoids using PLL and therefore suitable for weak grids as well. It is mentioned that the one without PLL can have oscillations in strong grids.

Key take-aways

There is really no need to have these two modes and therefore, no real need for having this switch-over. The conventional grid-forming control, which in this paper is named U-VSG control, should be able to support both weak and also strong grids, if tuned properly considering the maximum and minimum expected short-circuit levels. There is no need for the implementation referred to as PQ-VSG, which also has all known issues of using a PLL, such as stability issues.

In practice, a switchover between two control modes is more challenging than in simulations. Integrator outputs and all other state variable should be coordinated and communicated to avoid a harsh switchover. While the author suggests some solutions for a soft switchover, there are several factors such as hardware delays that are not considered here.

Discussion

Since there is no need to have both these grid-forming implementations, a switch over, as suggested in this paper, is also not necessary. A grid-forming converter should be tuned in a way that can withstand the minimum and maximum SCL with the same control implementation. Also, a PLL-less grid-forming implantation has become standard and there is no need for using a PLL-based grid-forming control strategy.

8.17 IET document: An Application of four-wire grid-forming power inverter in unbalanced distributed network [17]

Döhler, J., Mota,R.P., Archetti, J.A.G., Silva Junior, D.C., Boström, C., Oliviera, J.G.: An Application of four-wire grid-forming power inverter in unbalanced distributed network. IET Generation, Transmission & Distribution, Vol. 17, Issue 2, January 2023

Summary

Article shows a simulation study for a micro grid solution with up to 18 nodes of a 0,4 kV low voltage ac grid, which is connected via a 20kV/0,4 kV transformer to a medium voltage distribution grid. The grid is controlled by the overlaying medium voltage network during connection mode and via only one grid forming controller in islanding mode, when the connection switch is opened. It consists of three GFL converters and one GFM converter.

The controller and the model are described to control the different systems (positive, negative and zero sequence) in dq coordinates, controlling the positive and negative system via separated p and pi controllers for the different systems. The grid forming (GFM) converter only operates in islanding mode. Unbalancing of the load is also controlled by the GFM controller, while three of the four converters still operate in grid following mode (GFL).

Key take-aways

- Grid forming is possible in a small micro grid with one strong controlling converter in GFM mode
- Frequency deviation might be very high at the beginning of the islanding operation mode, but is inside the allowed range after a transient period, but oscillating much stronger than in grid connected mode
- Unbalanced load can be equalized by the GFM controller to near zero (voltage unbalanced factor VUF < 2%)
- Negative sequence values (e.g. for the voltage) could also be reduced more in islanded mode than compared to connected mode

Discussion

Questionable, if such an approach could be transferred to HVDC systems because of the missing available instantaneous power at HVDC systems without storage, compared to the LV systems with converters directly connected to battery systems.

8.18 IET document: Asking for fast terminal voltage control in grid following plants could provide benefits of grid forming behavior [18]

Ramasubramanian, D., Baker, W., Matevosyan, J., Pant, S., Achilles, S.: Asking for fast terminal voltage control in grid following plants could provide benefits of grid forming behavior. IET Gener. Transm. Distrib. 17, 411–426 (2023). https://doi.org/10.1049/gtd2.12421

Summary

The paper discusses a possible way to specify interconnection requirements for grid-forming inverters from the perspective of voltage control and shows the concept of fast terminal voltage control being able to provide grid forming like behavior.

Key take-aways

The inverters with a PLL can also be made to behave as a GFM if the control loops are appropriately structured.
The paper shows the concept of fast terminal voltage control being able to generate a GFM like behavior. The simulation results show that the inverter is stable and remains synchronized even in weak grid conditions (very low SCR). It is demonstrated that the inner current loop and the PLL are not the only control elements responsible for the inverter instability at low SCL.

The maximum time for the voltage response to bring out this GFM behavior can be specified in the interconnection requirements.
The performance of five different control strategies of GFM are evaluated and the results show the possibility of similar dynamic behavior through parametrization and tuning. This allows for the specification of a common performance-based interconnection requirement for future IBR and not an exact control type.

Suggested definition:
A grid forming resource is one which can transiently hold a fixed internal voltage phasor with local set-points of voltage and frequency. Following the transient time frame the internal voltage may change to accommodate power sharing.
A GFM control architecture may just be fast and robust voltage control.

Discussion

Through this concept of fast voltage control, the importance of the settling time can be noted. Then, the maximum response settling time of the IBR control loops should be specified in the interconnection standards (specify the voltage control-based connection requirements in a timely manner).

8.19 IET document: Impedance modelling and stability analysis of modular multilevel converter with different types of grid-forming control schemes [19]

Guo, H., Zhang, Z., Xu, Z.: Impedance modelling and stability analysis of modular multilevel converter with different types of grid-forming control schemes. IET Gener. Transm. Distrib. 17, 337– 353 (2023). https://doi.org/10.1049/gtd2.12668.

Summary

This paper [19] proposed equivalent impedance models for harmonic impedance-based stability analysis of two common grid-forming control implementations. Conducting harmonic impedance-based stability analysis is a must for HVDC converters to guarantee a stable operation of the system (not specific to grid-forming).

Key take-aways

- Analyzing the harmonic impedance of a grid-forming converter is necessary to ensure the stability of the converter and avoiding negative resistance values in all frequency ranges. Several real-world examples have shown the importance of such analysis for ensuring the continuous operation of the converter.
- If damping low frequency oscillations is to be considered as a grid-forming functional requirements, such analysis should be requested, and a minimum damping should be defined.
- Inclusion of all control loops including the outer controller loops is necessary for valid stability analysis, as these can significantly shape the converter input impedance.

Discussion

While the benefits of conducting the impedance-based harmonic stability is clear for all grid-forming converter, we are not focusing on specific implementations in this InterOPERA. However, if in the InterOPERA, the functional requirement of grid-forming converters will also include damping of low frequency oscillations, then such an analysis will be required for the working group to define a minimum damping at low frequency ranges.

8.20 IET document: An improved damping adaptive grid-forming control for black start of permanent magnet synchronous generator wind turbines supported with battery energy storage system [20]

Meng, J., Wang, D., Wang, Y., Guo, F., Yu, J.: An improved damping adaptive grid-forming control for black start of permanent magnet synchronous generator wind turbines supported with battery energy storage system. IET Gener. Transm. Distrib. 17, 354–366 (2023). https://doi.org/10.1049/gtd2.12753

Summary

This paper [20] proposes the application of BESS to PMSG-based WTGs with additional GFM control to provide black start. The GFM controller applied is VSG based. The studied system is made of two WTG-BESSs in parallel connected to a load bus forming an islanded microgrid. The system is first modelled in small-signal state-space domain and then analyzed in control-hardware in the loop studies.

Key take-aways

- An improved damping adaptive grid-forming control strategy with black-start and active support capabilities is proposed for PMSG. The strategy uses a natural constant function to adaptively increase the system damping, so as to suppress the frequency fluctuations better.
- A black-start process for grid-forming WTGs equipped with BESS is designed, which achieves a seamless black-start process through control and mode switching.
- The real-time simulation experiment platform of the PMSG island system built in this paper fully verifies the feasibility of the proposed black-start process. Under the conditions of basic wind speed, random wind speed, and failure after steady state, the PMSG-based islanded microgrid can successfully achieve black start and operate stably.

Discussion

The provision of black start is not one of the basic requirements from GFM converters. However, we are getting more and more mature in this aspect, so given the nature of our HVDC systems, maybe we could evaluate how to present black start as an additional functionality.

8.21 IET document: Hierarchical control scheme for proportional power sharing and robust operation in multiple virtual synchronization-based DC/DC converters [21]

Ji, X., Ye, C., Liu, Z., Ye, T.,Dong, X., Liu, D., Jiang, K., Cao, K.: Hierarchical control scheme for proportional power sharing and robust operation in multiple virtual synchronization-based DC/DC converters. IET Gener. Transm. Distrib. 17, 380–390 (2023). https://doi.org/10.1049/gtd2.12548

Summary

Article proposes a hierarchical control scheme to achieve higher efficiency and superior anti-disturbance ability for multiple DC/DC converters with virtual synchronization-based control. The primary control layer enables proportional power sharing by using improved virtual synchronization control for each DC/DC converter, which aims at eliminating the influence of line parameter mismatch among converters. The secondary control layer deals with DC voltage stability improvement through the extended disturbance-observer-based back-stepping control with the consideration of external power fluctuation on the whole system. This control deals with the DC voltage stability improvement issue with the tracking of external time-varying disturbance, which can obviously eliminate external power fluctuations on the whole system. Disturbance-observer-based back-stepping control eliminates the oscillations of the system. Two control levels are integrated as the hierarchical control architecture to realize different control objectives in different time scales, while only neighboring communications and DC voltage information are needed among the system. Theoretical analysis and simulations on PSCAD/EMTDC verify the validity and superiority of the proposed hierarchical control scheme. Describes a simple mathematical approach to simulate the DC/DC converter and the synchronization-based control.

Key take-aways

- The paper does not contribute so much directly linked to grid forming capabilities but presents an interesting control strategy to control a grid with parallel dc/dc converters.
- Droop characteristic has to be adopted to the power capacity, to avoid a centralized grid controller for the dc system but is not sufficient to balance out disturbances.
- Virtual-synchronization control can be used for the DC/DC converters since it imitates the rotor dynamics of the SG and presents superior dynamic response in case of disturbance compared with conventional droop control.
- Efficient power sharing and robust operation ability cannot be guaranteed in a multiple parallel-operated DC/DC converter system.
- Eliminating oscillations needs a special approach in a dc grid with multiple decentralized self-controlled converters, the droop characteristic is not sufficient.
- A hierarchical control scheme, including the proportional power sharing primary control and the back-stepping-based secondary control method, can achieve higher efficiency and superior anti-disturbance ability for multiple DC/DC converters with virtual synchronization-based control.

Discussion

Can this control scheme for a micro grid be applied to an HVDC system without battery storage and a huge amount of available instantaneous active and reactive power? When oscillations occur or strong disturbances according to stationary power transmission take place, available instantaneous energy and power is needed to eliminate the deviations, otherwise the voltage will drop and jump to fast, to balance out these fluctuations, is the stored energy of the HVDC system, meaning capacitor-based energy, sufficient, to react on disturbances?

8.22 Grid-Forming Inverter-based Wind Turbine Generators: Comprehensive Review, Comparative Analysis, and Recommendations [22]

Summary

This paper [22] presents a review of GFM controls for WTGs, which covers the latest developments in GFM controls and includes multi-loop and single-loop GFM, virtual synchronous machine-based GFM, and virtual inertia control-based GFM.

A comparison study for these GFM-based WTGs regarding normal and abnormal operating conditions together with black-start capability is then performed. The control parameters of these GFM types are properly designed and optimized to enable a fair comparison. In addition, the challenges of applying these GFM controls to wind turbines are discussed, which include the impact of DC-link voltage control strategy and the current saturation algorithm on the GFM control performance, black-start capability, and autonomous operation capability.

Finally, recommendations and future developments of GFM-based wind turbines to increase the power system reliability are presented.

Key take-aways

This paper categorizes the GFM WTGs based on the regulation strategies of DC-link voltage, as shown in Fig. 3. The GFM WTGs are classified into three categories:

1. G-GFM: GSC controls DC voltage.
2. M-GFM: MSC controls DC voltage.
3. E-GFM: External energy storage controls DC voltage.

In each category, two types of GFM controls are classified according to the inner control loop of the grid-forming controller: the multi-loop control (MGFM) and single-loop control (SGFM). The MGFM types include the inner current and AC voltage control loops, while the SGFM types consist of only the AC voltage control loop.

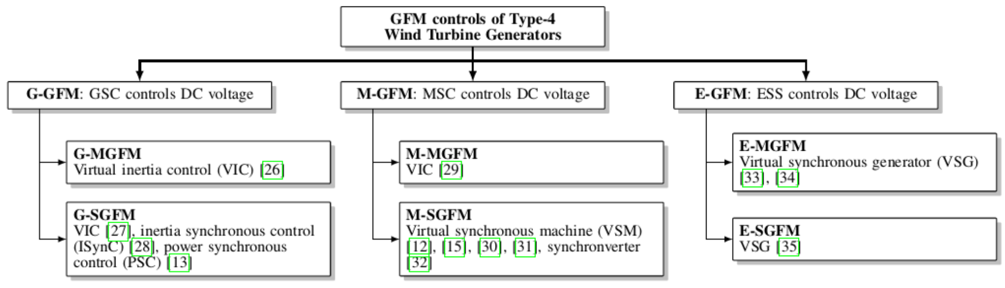


Fig. 3. Existing grid-forming controls of Type-4 wind turbine generators.

Figure 24. Existing grid-forming controls of Type 4 wind turbine generators. [22]

The first category of GFM-WTG is the G-GFM, in which the grid-side converter controls the DC-link voltage. An outer DC-link regulator is designed in addition to the inner control loop of the grid-side converter. The DC-link voltage is controlled by adjusting the instantaneous phase angle of the terminal voltage. The DC-link voltage regulators mimic the inertia support of the synchronous generator by allowing the variation of DC-link voltage in an acceptable range, which has been presented in different names, such as virtual inertia control (VIC), inertia synchronous control (ISynC), and power synchronous control. The pitch and machine-side controllers are kept the same as the GFL type.

The second category of GFM WTG is the M-GFM, in which the machine-side converter regulates the DC-link voltage, whereas the grid-side converter is designed for managing output power. The grid-forming controllers implemented in the grid-side converter also mimic the inertia characteristic of synchronous generators, although different controller names have been presented, such as VIC, virtual synchronous machine (VSM), and synchronverter. The last category of GFM WTG is the E-GFM, in which the DC-link voltage is controlled by an external energy storage system (ESS). This approach provides an additional degree of freedom for grid-side controllers while retaining all control functions of pitch and machine-side controllers. VSG-based GFM controls are mainly used in this type. As the DC-link voltage is managed constantly by the external ESS, most exiting GFM methodologies available in the literature can be used for the grid-side converter without any modification, such as droop control, power synchronization control, and virtual synchronous generator. It is anticipated that using additional ESS devices introduces technical benefits because ESS can play the role of energy buffer to mitigate the fluctuations in wind power or support grid during the disturbance. However, this GFM type increases the complexity of the WTG control system and total investment cost. Overall, it can be found that all existing GFM control methodologies for WTGs try to mimic the inertia characteristic of synchronous generators. This paper investigates only GGFM and M-GFM categories as they are potential solutions for developing GFM WTG from the existing GFL type. Among two categories, four types of GFM WTGs will be presented in the following sections, which are:

- G-GFM with multi-loop control (G-MGFM) - *Figure 25*
- G-GFM with single-loop control (G-SGFM) - *Figure 26*
- M-GFM with multi-loop control (M-MGFM) - *Figure 27*
- M-GFM with single-loop control (M-SGFM) - *Figure 28*

To ensure a fair comparison, the G-MGFM and G-SGFM types use the same outer VIC scheme, while M-MGFM and M-SGFM types use the same outer VSM scheme. The blue color depicts the difference between the GFM and GFL controls of WTGs in the schematic diagrams in *Figure 25* - *Figure 28*.

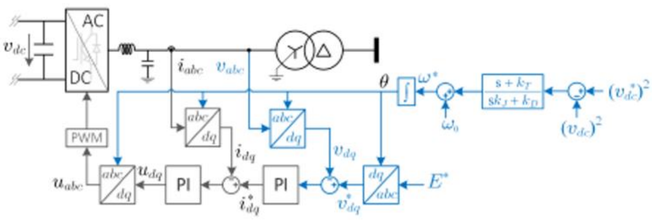


Figure 25. Schematic diagram of G-MGFM wind turbine generator [22]

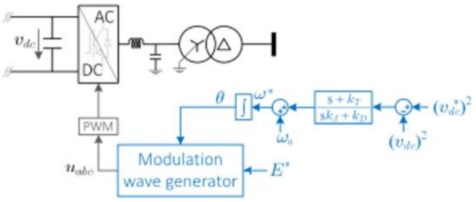


Figure 26.Schematic diagram of G-SGFM wind turbine generator [22]

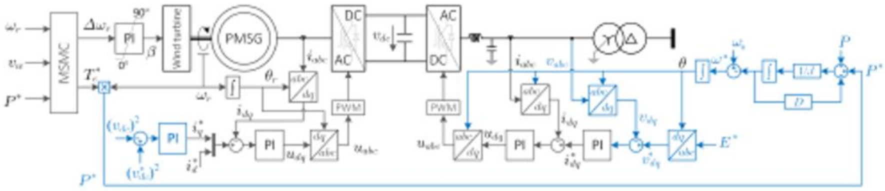


Figure 27. Schematic diagram of M-MGFM wind turbine generator [22].

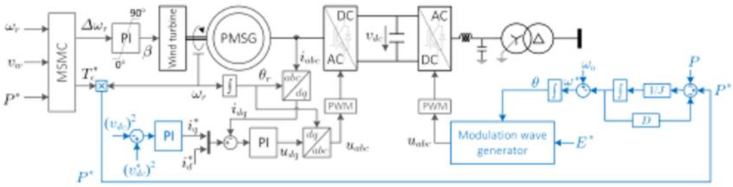


Figure 28.Schematic diagram of M-SGFM wind turbine generator [22].

Four GFM methodologies are discussed: multi-loop GFM (S-MGFM and M-MGFM) and single-loop GFM (S-SGFM and M-SGFM). A comparative study has been conducted to evaluate their performances. It has been observed that the M-MGFM and M-SGFM types provide a better performance in fault conditions as the DC-link voltage is controlled by the machine-side converter which is decoupled from the grid's disturbance. The tested result under fault conditions showed that the single-loop GFM types have a higher stability margin than the multi-loop GFM types. This paper revealed that the DC-link voltage has a significant impact on the performance of the GFM WTGs that should be taken into consideration for control design.

Discussion

This article is focused on GFM applied to WTGs; however, some key takeaways could be applicable also to GFM applied to HVDC. For example, it is found that the single-loop GFM types have a higher stability margin than the multi-loop types. Furthermore, the best performances are achieved when the machine-side converter is to control the DC-link voltage. Could this be useful to GFM in HVDC applications?

8.23 Grid Forming Technology – Bulk Power System Reliability Considerations [25]

Summary

This is a white paper from NERC (North American Electric Reliability Corporation) published in December 2021. It provides a concrete definition of grid-forming control and a list of expected functions from GFM IBRs. In addition, it summarizes the challenges in terms of capabilities and performance from GFM IBRs and provides recommendations regarding interconnection requirements, modeling, and studies on GFM IBRs. Last but not the least, this white paper has a specific focus on bulk power system (BPS) application of GFM IBRs.

Key take-aways

1. Definition
   GFM control for BPS-connected IBRs are controls with the primary objective of maintaining an internal voltage phasor that is constant or nearly constant in the sub-transient to transient time frame. This allows the IBR to immediately respond to changes in the external system and maintain IBR control stability during challenging network conditions. The voltage phasor must be controlled to maintain synchronism with other devices in the grid and must also regulate active and reactive power appropriately to support the grid.
2. Functions
   (1) Islanded operation
   (2) Synchronization and stable operation with others in the grid
   (3) Frequency control
   (4) Voltage control and reactive power support both within and outside continuous operation
   (5) Oscillation damping
   (6) Active low-order harmonics cancellation
   (7) Black-start
3. Modeling and studies

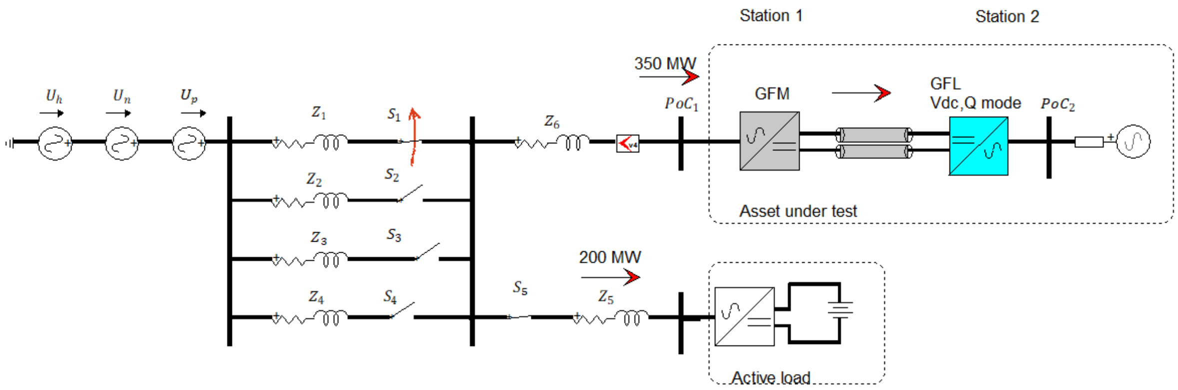
Positive sequence models and EMT models for GFM IBRs are needed for interconnection studies and system planning. Considering the confidential nature of GFM controls, it is recommended that the WECC Modeling and Validation Subcommittee or other industry modeling groups start GFM model development with support from OEMs and research organizations in the near future.

9 Appendix 2: Generic point-to-point GFM simulations

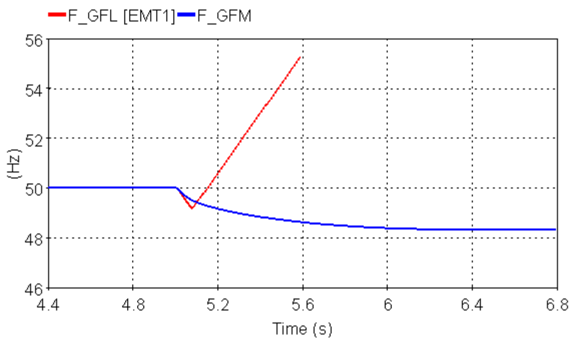
This appendix presents a series of GFM control related simulations on a point-to-point HVDC connection. The simulations are performed using a generic EMT model. The intention of displaying the simulation results is to provide illustration of the coupling between AC and DC side dynamics related to GFM control and the core GFM functionalities defined within this document. The results are not intended for comparison or benchmarking of real HVDC vendor solutions and should not be used for this in any way.

9.1 Self-synchronization functionality of GFM converters

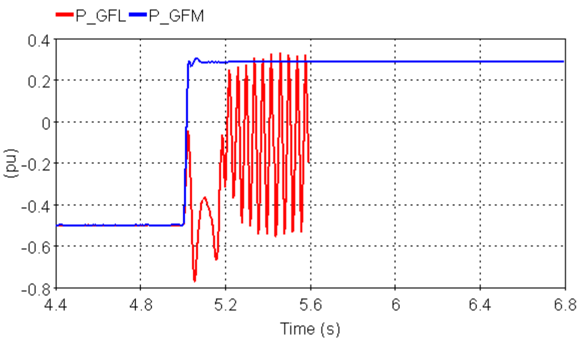
The following provides some simulation results comparing different behaviour of an HVDC converter station in GFM and GFL control when it loses the last synchronous connection. The test system shown as below is recommended by the FNN guidelines [3].



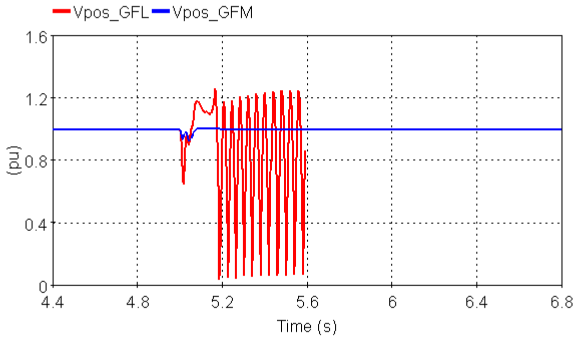
Station 1 is the HVDC converter station under test. The loss of the last synchronous connection is triggered for Station 1 when the breaker S1 is opened. GFM and GFL controls are implemented respectively on Station 1 to compare the difference in its behaviour, and the results are shown as follows.



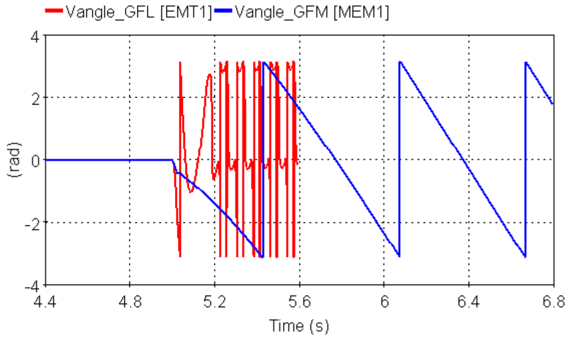
System frequency



Active power of Station 1



Voltage magnitude of Station 1



Voltage phase at Station 1 (GFM: phase of internal voltage phasor; GFL: grid voltage phase estimation from PLL)

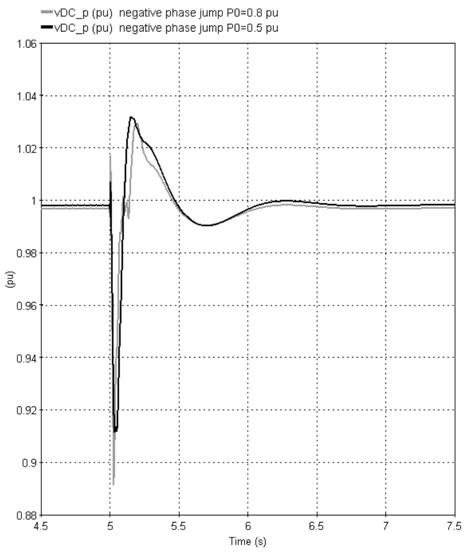
The breaker opens at t = 5 s. The blue curves show the responses of Station 1 in GFM control while the red ones are responses in GFL control. From the results, it is not difficult to see that, when in GFM control, Station 1 survives the loss of the last synchronous connection and achieves standalone operation, where it is the only voltage source in the AC grid. However, when in GFL control, Station 1 cannot survive the loss of the last synchronous connection, and therefore it cannot be considered to have standalone operation capability in such case.

As mentioned at the beginning of the chapter, the results here are used only for illustration purpose, and not to be used for benchmarking of GFM behavior in any practical implementations. The purpose of simulation is to illustrate the self-synchronization capability and stand-alone operation.

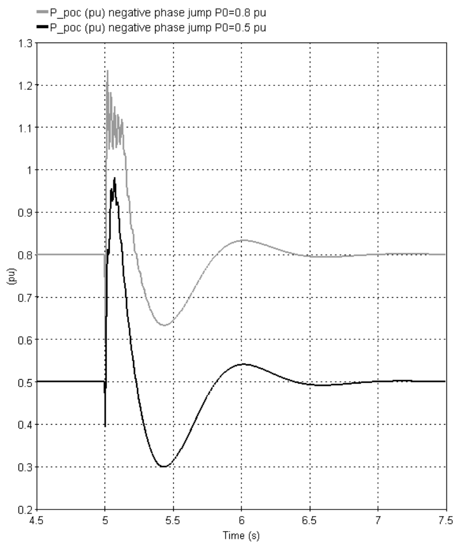
9.2 Phase jump active power leading to current limitation

Simulation conditions:

- Initial active power: 0.8 and 0.5 pu (2GW base power)
- DC voltage: ±525 kV
- SCR=2.5 at POC (GFM side)
- Disturbance: phase jump of - 30° at t=5s
- Converter current saturation (current limit=1.1 pu)



DC voltage (pu)

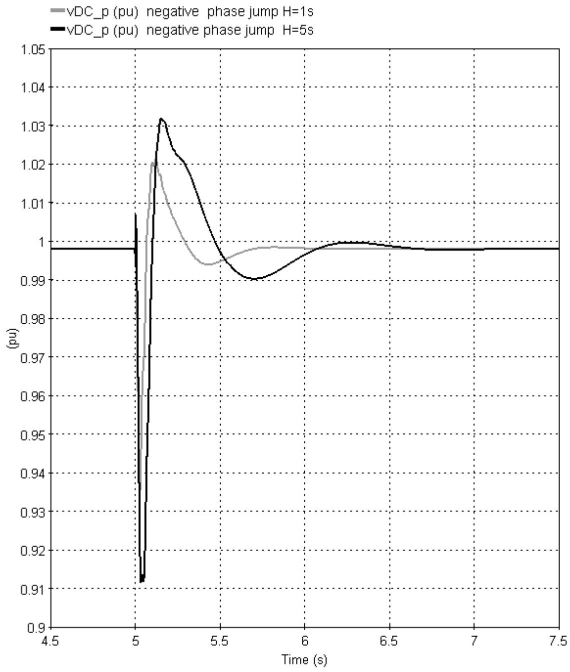


Active power output (pu)

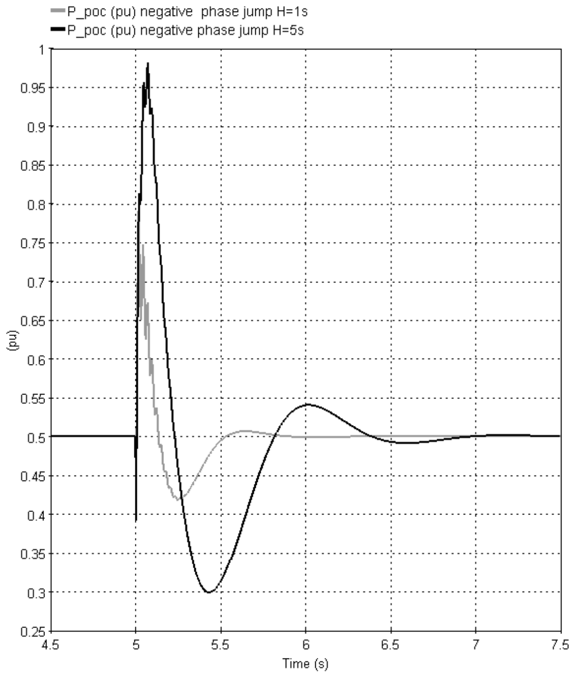
9.3 Effect of the inertia constant H of the GFM control

Simulation conditions:

- Initial active power: 0.5 pu (2GW base power)
- DC voltage: ±525 kV
- SCR=2.5 at POC (GFM side)
- Disturbance: phase jump of - 30° at t=5s



DC voltage (pu)

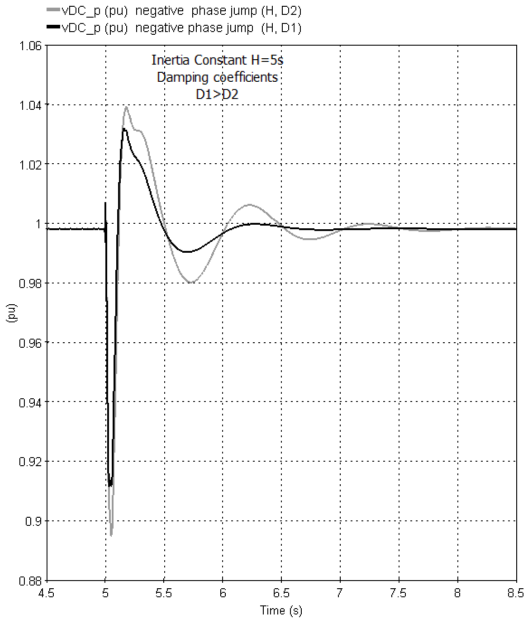


Active power output (pu)

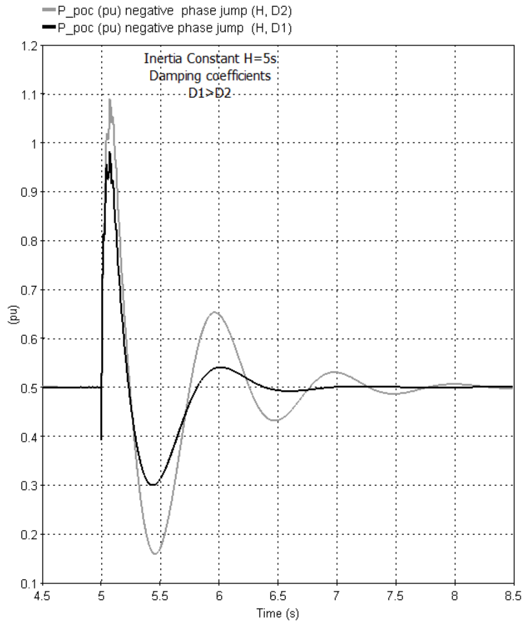
9.4 Effect of the damping coefficient D of the GFM control

Simulation conditions:

- Initial active power: 0.5 pu (2GW base power)
- DC voltage: ±525 kV
- SCR=2.5 at POC (GFM side)
- Disturbance: phase jump of - 30° at t=5s



DC voltage (pu)

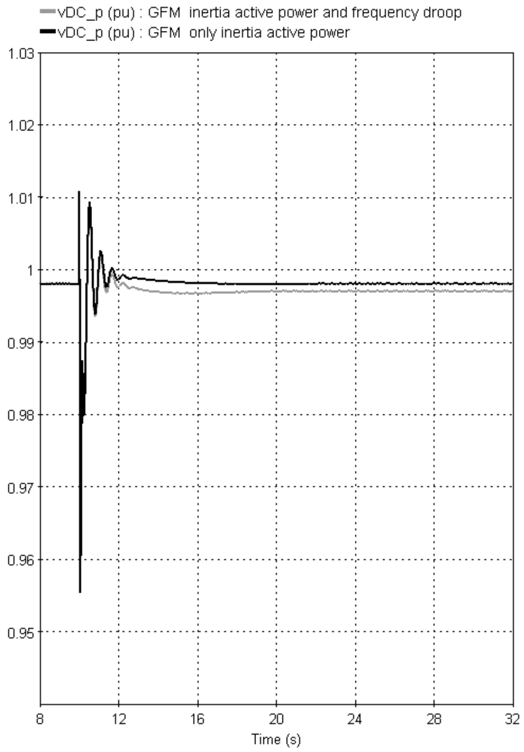


Active power output (pu)

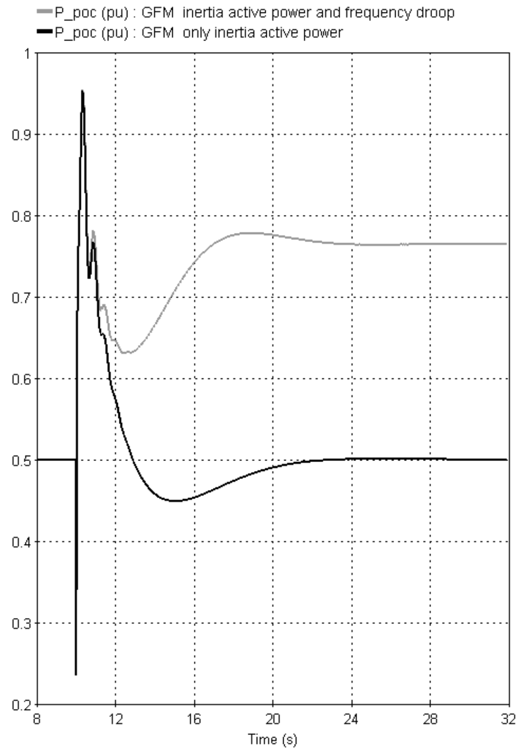
9.5 Inertial active power to frequency changes

Simulation conditions:

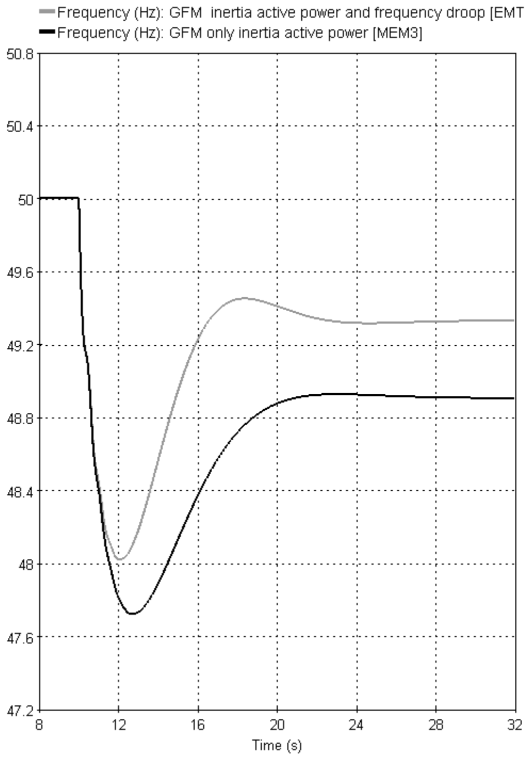
- Initial active power: 0.5 pu (2GW base power)
- DC voltage: ±525 kV
- SCR=2.5 at POC (GFM side)
- Network 1: low order system model for estimating the frequency behaviour
- Disturbance: at 10 s load step on network 1 (GFM side)
- RoCoF (500 ms): - 2 Hz/s at t=10 s



DC Voltage (pu)



Active power output (pu)

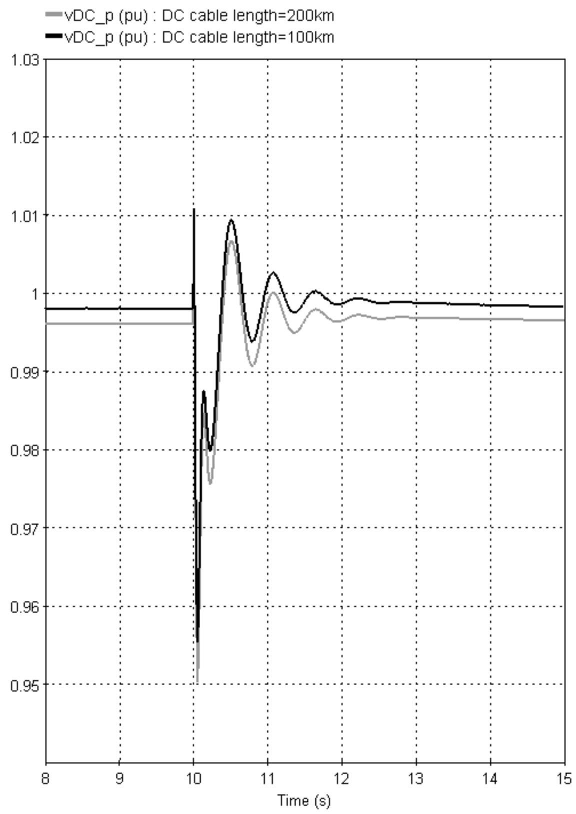


Frequency (Hz)

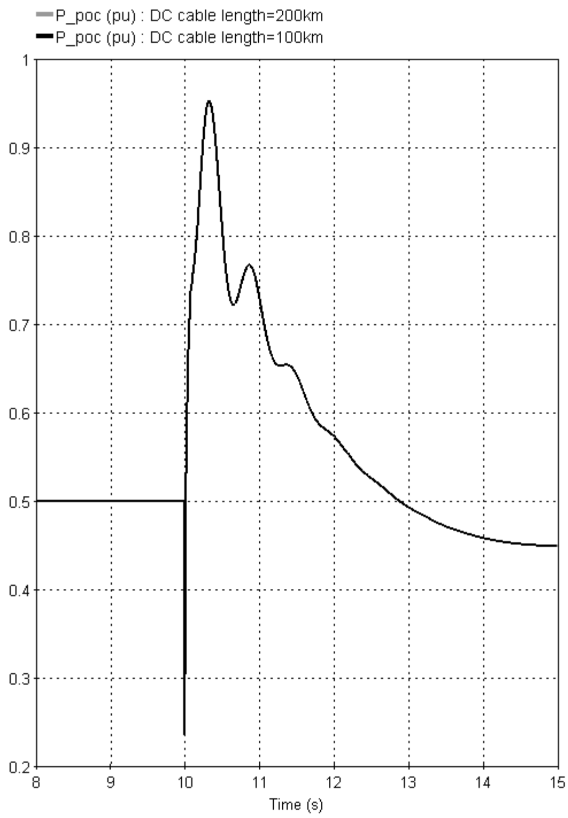
9.6 Effect of the length of the DC cable

Simulation conditions:

- Initial active power at the point of connection: 0.5 pu (2GW base power)
- DC voltage: ±525 kV
- SCR=2.5 at POC (GFM side)
- Network 1: low order system model for estimating the frequency behaviour
- Disturbance: at 10 s load step on network 1 (GFM side)
- RoCoF (500 ms): - 2 Hz/s at t=10 s



DC voltage (pu)



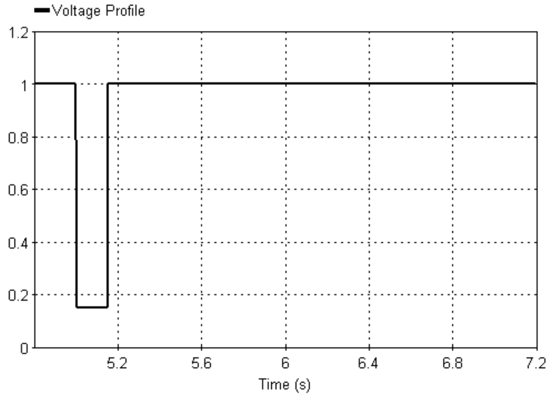
Active power output (pu)

From the results we can see that the available energy in the DC cable is so small to impact the active power output from the GFM converter.

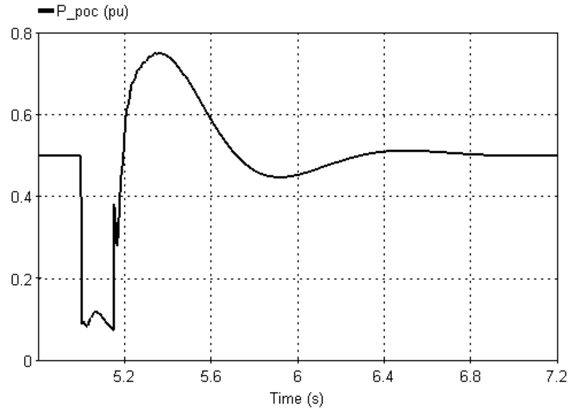
9.7 AC fault response

Simulation conditions:

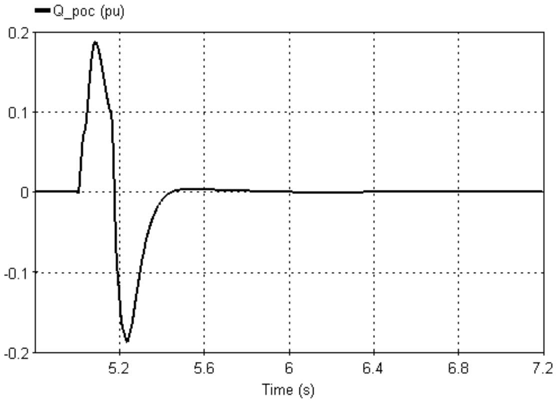
- Initial active power: 0.5 pu (2GW base power)
- DC voltage: ±525 kV
- SCR=2.5 at POC (GFM side)
- Voltage dip 0.15 pu (base voltage 400 kV) at t=5 s and lasts 150 ms



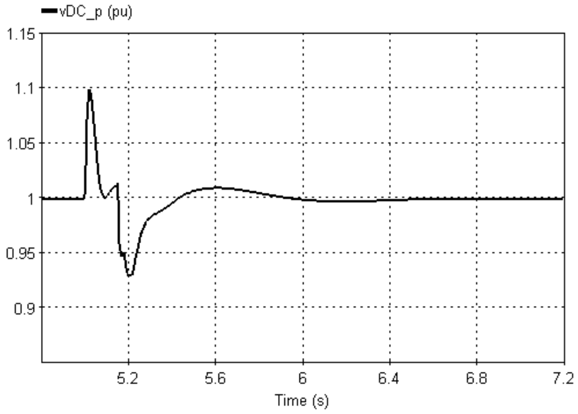
AC Voltage at connection point (RMS, pu)



Active power output (pu)



Reactive power output (pu)



DC voltage (pu)