Grid Forming Control for HVDC Systems: Opportunities and Challenges

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Abstract

The aim of this paper is to highlight the opportunities and challenges of Grid Forming Control (GFC) for High Voltage Direct Current (HVDC) applications. A special focus will be on contradictory GFC performance requirements from European Transmission System Operators (TSOs). The impacts of these requirements on AC grid, HVDC performance and hardware are discussed.

Introduction

Due to the increasing integration of renewable energy sources (RES) and a corresponding reduction of conventional generating units, there is a demand from the power-electronic converters to provide grid-forming behavior through proper control of the converter systems nowadays. There are different ways of implementing GFC. Reference [1] gives an overview on GFC methods. The most interesting methods are: Voltage Source Control [2], Droop-based Grid Forming Control [3], Power Synchronization Control [4], Virtual Synchronous Machine Control [5] and [6], and PLL-Based Modified Current-Control methods [7]. The common feature of GFC is that the control should be equipped with functionalities that enable inertia and frequency support, islanding operation, black-start, and synchronization capabilities. Many papers have been published in GFC area, but GFC for HVDC systems is scarcely addressed. Nevertheless, the so-called "GFC" has been successfully applied in the HVDC installations where the GFC is necessary, for example, HVDC converters connected to weak or extremely weak AC grids or islanded network (offshore wind) with zero or very limited inertia [8] and [9]. In fact, according to [10], GFC may not be appropriate when the AC grid is very strong and it may become unstable under such conditions.

The aim of this paper is to highlight the opportunities and challenges of GFC for HVDC applications. A special focus will be on contradictory GFC performance requirements from European Transmission System Operators (TSOs). The impacts of these requirements on AC grid, HVDC performance and hardware are discussed.

The paper is organized as follows: a brief description about the operating principle of HVDC is given. Following that, requirements on Grid-forming behavior according to existing Grid codes/standards are summarized. Next, some of requirements which deserve further efforts from both TSOs and vendors are highlighted in order to reach a common goal of using HVDC to support a greener AC grid in the best way. Finally, some conclusions based on observations from simulation results are presented.

Principle of VSC-HVDC operation

Fig. 1 shows a schematic diagram for a VSC-HVDC system based on Modular Multilevel Converter (MMC) with Half Bridge cells. The two stations can be connected to the same or different AC grids. If the two stations are connected to the same grid the HVDC link is referred to as "embedded HVDC link". Ignoring the active power losses in the transformer and phase reactor, the phasor diagram for the point of common coupling (PCC) voltage (U_{pcc}), the converter valve voltage (U_v) and the current at valve side of transformer (I_v) is shown in Fig. 2. The active and reactive power at PCC can be expressed as:

$$P = U_{pcc} I_v \cos\varphi \approx \frac{U_v U_{pcc}}{X} \sin\delta \tag{1}$$

$$Q = U_{pcc} I_v \sin\varphi \approx \frac{U_{pcc}(U_v \cos\delta - U_{pcc})}{X} \tag{2}$$

where $X = \frac{X_r}{2} + X_t$ i.e., X is the total equivalent reactance of the transformer short circuit reactance (X_t) and arm reactor (X_r).

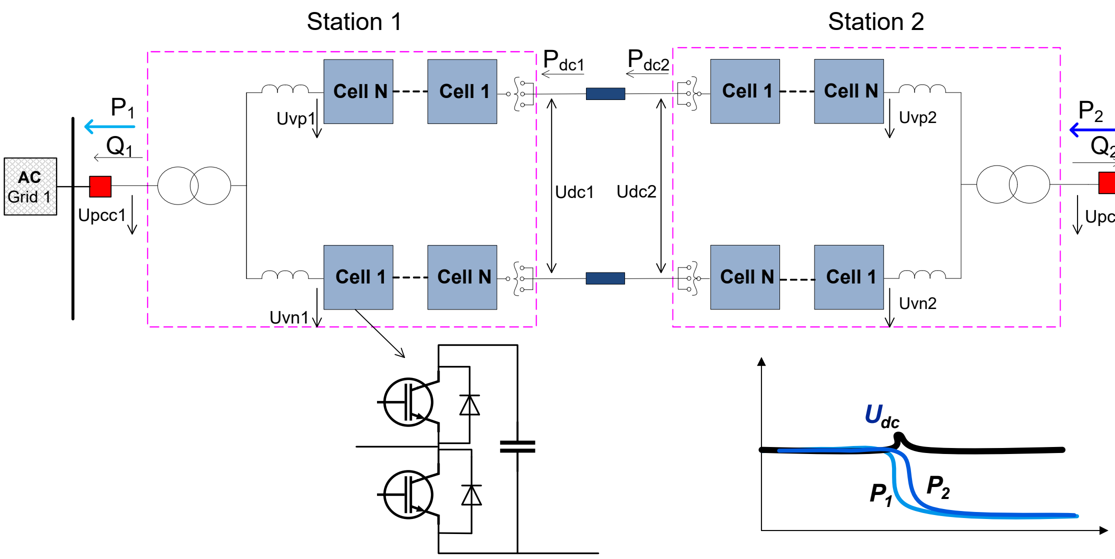

Fig. 1: A schematic diagram of a point-to-point VSC-HVDC system.

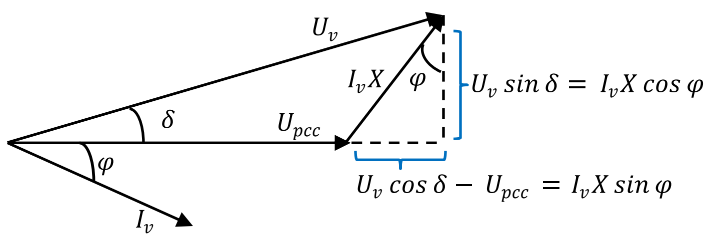

Fig. 2: Phasor diagram of voltages and current (quantities are in p.u.).

The active power is controlled by controlling the angle difference between U_v and U_{pcc}, whereas the reactive power is controlled by amplitude of U_v. Active power should be controlled in a coordinated way. One station controls the active power (station 1 in this case), and other station controls the DC voltage (station 2 in this case) such that the active power on the DC side is balanced. If the losses in the HVDC system is ignored, the active power in the DC voltage control (U_{dc}-control) station P_2 follows the active power in the active power control (P-control) station P_1 except for transient as shown in Fig. 1 supposing that the active power and DC voltage are controlled in a coordinated way. This means that HVDC system (within purple dash-line) is a transmission medium.

However, differing from AC transmission mediums, each station can control AC voltage or reactive power independently which can support the respective AC grid voltage, and it can also vary the active power (manually or automatically) to support AC grid frequency or facilitate power trading. It is also possible to switch the P-control mode to Frequency & Voltage control which is used during grid restoration (black start) or for forming grids of an islanded network e.g., offshore wind farms [2]. In that case the other station should operate in U_{dc}-control mode.

Various benefits can be achieved with HVDC if it's operated stably a coordinated manner. However, if the performance requirements are not coordinated e.g., if great deal of emphasis is put on certain requirements while overlooking other requirements or impacts, there is a risk of jeopardizing the HVDC system stability and/or having negative impact on the AC system stability. Examples of such requirements (which are associated with grid-forming behavior) in existing grid codes/technical specifications are discussed through simulation results presented in this paper.

Grid-forming behavior – requirements from Grid codes/standards

Requirements for Grid Forming behavior are already in place in German Grid Code [11] and [12]. In [12] the expected behavior is elaborated with illustrative plots for different test cases such phase jump, frequency ramp AC faults, Islanding etc. The plots can be used as references cases when verifying GFC behavior. It's however unclear if the tests and reference plots in [12] are all applicable for both P-controlling and U_{dc}-controlling stations in an HVDC link. Furthermore, the assumptions used for converter energy storage (i.e., finite or infinite) when the reference plots were created are also unclear. Requirements for Grid Forming Capability has recently been added to the National Grid (UK) grid code [13], where new terms such as Phase Jump Power, Inertia Power and Control-based Power have been added. For each type of power there is a certain requirement. What's more pronounced in the requirements in [13] is that the use of virtual impedance in emulating voltage source behavior is not permitted. From the control structure presented in [14], it seems it's desired to strictly emulate synchronous machine behavior. There is also a requirement to withstand a voltage phase jump as high as 60 degrees. The ENTSO-E technical report [15] sets the following Grid Forming requirements:

- Creating system voltage
- Contributing to fault level
- To act as sink for harmonics
- To act as sink for unbalance
- Contribution to inertia
- System survival to allow effective operation of Low Frequency Demand Disconnection (LFDD)
- Preventing adverse control interactions

IEEE has recently published the standard P2800 [16] which, when it comes to HVDC, is only applicable at point of connection of a VSC-HVDC connecting Isolated inverter-based resources (IBR). There are no clear requirements for other types of HVDC such HVDC connecting two different AC networks (interconnector) or an HVDC connected to two busbars within a meshed synchronous AC system (referred to as an Embedded HVDC [17]).

The grid codes/Technical reports share one common thing i.e., the converter should behave as a voltage source behind impedance to provide inherent support for frequency and voltage support in response to grid disturbances such as phase jump and voltage dip/swell. The current limitation philosophy during transients is hardly discussed and it's left as an area of research for industry/academia.

Apart from [14], no other document discusses the energy storage limitation in HVDC systems. In [14] the limited energy storage available in HVDC system is briefly discussed along with the measures to be taken if grid-forming behavior such phase jump power or inertia power is expected from the onshore station in an HVDC system connecting offshore wind farms. The conclusion in [14] is that there is a need for additional energy storage to be installed in the onshore station if HVDC and wind turbines are to be operated in the traditional way as i.e., HVDC offshore station in Frequency & Voltage control mode, HVDC onshore station in U_{dc}-control mode, and wind turbines in grid-following mode. It's also unclear from [11] and [13] whether it's expected or not that both HVDC stations operate simultaneously in Grid Forming mode.

Grid-forming behavior - unharmonized requirements

Inertial response versus active power response

In recent European grid codes [11], [12] and [13], there are new requirement of providing inertial support with a certain active power contribution during transients, such as phase jump or load rejection. Fig. 3 shows the active power responses (left side figure) for a transient event of $+10$ degrees phase jump in the network voltage. The simulated phase jump is in the grid connected to the station in P-control mode. The considered AC network short circuit ratios (SCRs) for P-control and U_{dc}-control stations are 6 and 10 (based on the system parameters listed in Table I), respectively. During this transient, the power response is driven primarily by the phase jump [18]:

$$\Delta P_{\delta} = \frac{U_v\, U_{pcc}}{X}\sin(\Delta\delta) \tag{3}$$

where $\Delta\delta$ is the change in the angle between U_v and U_{pcc}.

In addition, there are also the contributions from inertia power (proportional to RoCoF); frequency droop dependent power order change (proportional to frequency deviation) and damping power (due to emulating damping in synchronous machine). The figure shows that the higher the inertia, the more the power variation is. The figure on the right side shows the corresponding power from U_{dc}-control station where the DC voltage is maintained within $\pm 6\%$. It shows that the source of energy for inertial response provided by the P-control station is actually the AC network connected to U_{dc}-control station.

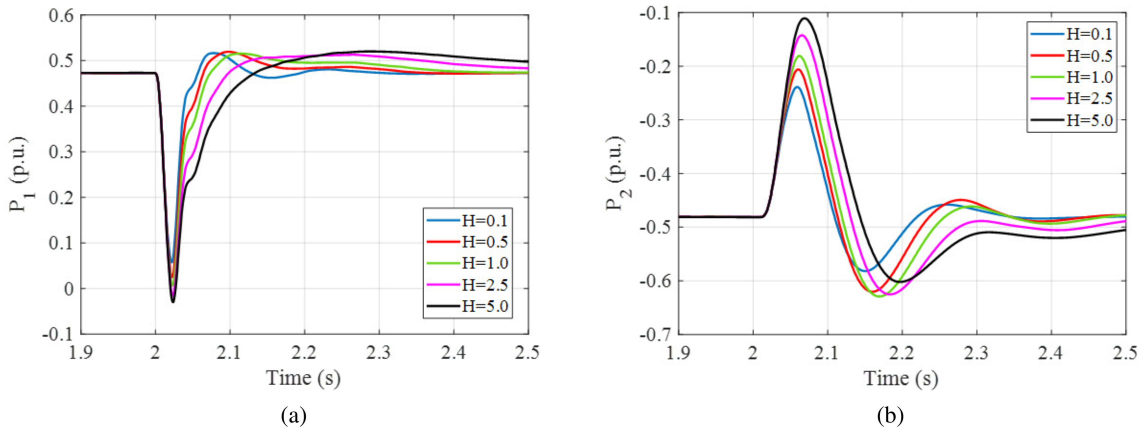

Fig. 3: Active power responses to a $+10$ degrees phase jump in AC network connected to the P-control station while different inertia constants (H) are considered (for the P-control station): (**a**) from P-control station; (**b**) from U_{dc}-control station.

It's to be noted that in this paper in all simulations made in the converter the convention for active power is positive toward the grid. Moreover, the simulation is made based on a typical HVDC link with realistic main circuit parameters, control & protection.

While introducing new requirement related to inertial response, the traditional requirements are still maintained as they have been e.g., HVDC system to recover its active power faster post AC faults and to change its active power rapidly either during a step change in active power order or during Emergency Power Control (EPC). Typically, the traditional requirement for post fault active power recovery is to recover to 90% of pre-fault power within 150 - 200 ms. Regarding EPC, different speeds of active power change may be required, but in some cases reduction from full power to zero power is required to take place within 5 – 10 ms. It should be realized that the requirement on the inertia will have impact on the speed of P-control. Fig. 4 shows the active power a 10% step change in active power simulated for different inertia constants (H). It can be seen from the figure that the step response time increases as H is increased.

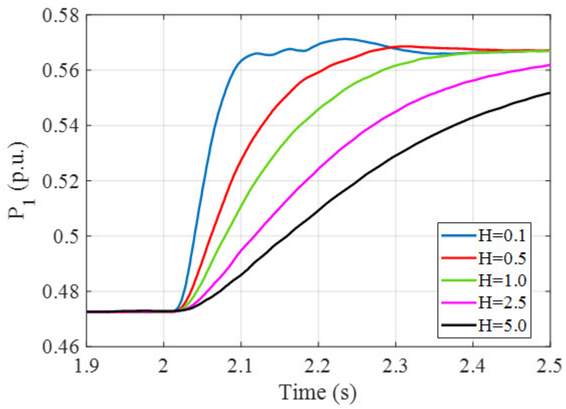

Fig. 4: Active power under a 10% step change in active power reference for different inertia constants.

It is clear from Fig. 4 that increasing inertia will slow down the active power step response. Thus, the requirement on inertial response can also affect the performance of a fast-acting function like EPC and also power oscillation damping (POD) controller. Similarly, increasing inertia on the U_{dc}-control station will slow down the DC voltage step response.

Requirements of high inertia versus limited energy in HVDC system

In UK there is a plan to specify how much inertia that each grid-forming converter should provide [13]. The range could be 2 - 25 MWs/MVA, as per [14]. As mentioned previously, HVDC is just a transmission medium and the energy available in HVDC system (MMC submodules & DC cables/overhead lines, etc.) is limited typically 100 - 200 ms which is defined by full discharge at rated power. However, availability of more than 90% of this energy is a prerequisite for producing the necessary level of AC voltage which allows the converter to operate properly. Thus, the energy for grid support needs to come from AC grids connected to remote station. As shown in Fig. 3, it is possible for the P-control station to provide a large inertia as long as the U_{dc}-control is sufficiently fast to maintain the DC voltage stability and the AC network connected to U_{dc}-control station can tolerant transient power variation. However, if one of the two mentioned preconditions is not fulfilled e.g., the U_{dc}-control is not fast enough for other design requirement reason, the large inertia on the P-control station could affect the DC voltage, and the DC voltage in turn can negatively affect the AC voltage stability which will be further addressed in the last subsection). Furthermore, there is a risk of trip if inertia is high when there is a large grid disturbance (e.g. a solid 3-phase fault) in close vicinity of U_{dc}-control station when operates as an inverter.

Large phase jump versus limited impedance

In [12], there is a requirement to withstand a phase jump up to 60 degrees and it's not permitted to use a virtual impedance in GFC. Equation (3) shows that the transient power depends on the AC grid voltage phase change and reactance X. The equivalent reactance X of HVDC converter (typically less than 0.3 p.u.) is lower than synchronous machine reactance. Suppose that the voltage is 1 p.u., then a phase jump of 60 degrees would lead to more than 1 p.u. power change. This implies that the converter is forced to operate outside its power capability, and the protection would act, which can eventually trip the converter. This trip can be mitigated by increasing X in (3) via using an additional virtual impedance, i.e., X can be increased without physically modifying any main circuit equipment by introducing an additional virtual impedance in the control. Fig. 5 shows the simulation of an event of 60 degrees phase jump in the grid connected to station 1 (see Fig. 1) while the considered AC network SCRs for both stations are 40. In Fig. 5, the blue curves are the results from a GFC with a proper virtual impedance included whereas the red curves are the results from a GFC without any virtual impedance. The figure shows that with a proper virtual impedance it is possible for the converter to limit the transient currents under a sudden large phase jump in AC grid, which in turn limits the power into/from the converter. In this way, the trip of HVDC converter can be avoided allowing the HVDC to remain in service to support the AC grid.

As stated earlier, the internal impedance of HVDC converter station is typically smaller than a synchronous machine impedance in per-unit value. Another key point to mention is that the transient current capability of converter is also smaller than a synchronous generator. On the other hand, HVDC converter has the advantage of being flexible in control. Therefore, it is important to utilize its flexibility in control, for instance, to use a virtual impedance to limit the current without significantly affecting its behavior as a voltage source behind an impedance.

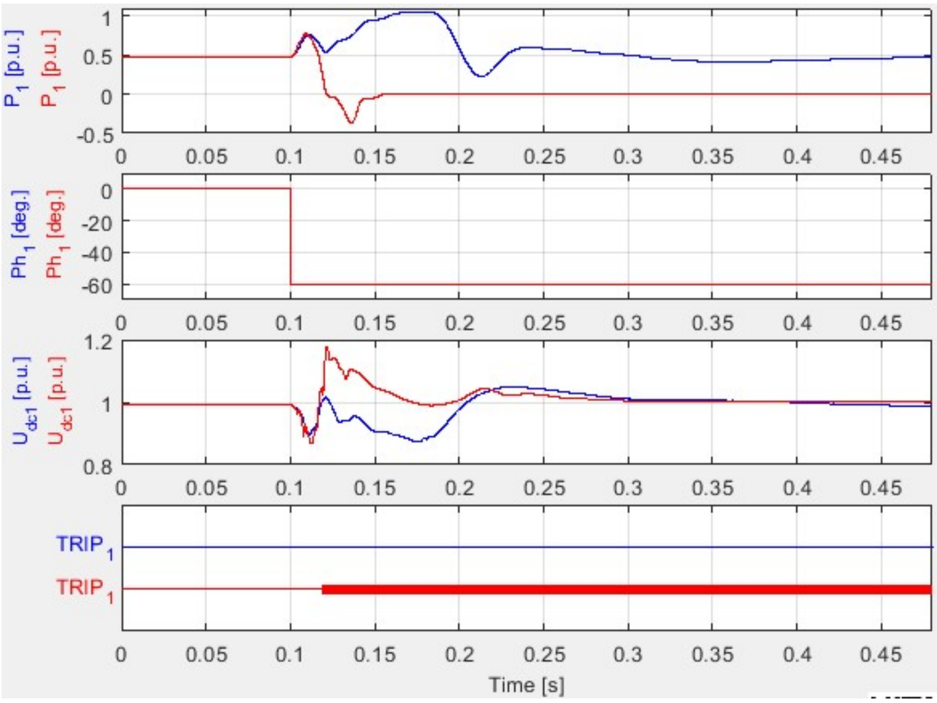

Fig. 5: Simulation of an event of 60 degrees phase jump in the grid connected to station 1. Blue curves: with virtual impedance; red curves: without virtual impedance. Subplot 1: active power at PCC of P-control station, subplot 2: voltage phase of AC grid connected to P-control station, subplot 3: dc voltage of P-control station, subplot 4: trip indication for P-control station.

Inertia support versus stability of DC voltage

Providing grid forming behavior has become mandatory requirement [11], [12] and [13]. Furthermore, some TSO is planning to specify how much inertia that each grid-forming converter should provide [13]. As discussed earlier, these requirements may be fulfilled for the P-control station under two important pre-conditions. One of the pre-conditions is the fast U_{dc}-control. However, increasing inertia in the U_{dc}-control station will slow down the DC voltage response (in a similar way as it does for P-control station, see Fig. 4). Obviously, the U_{dc}-control station can not be designed to provide large inertia for the purpose of accommodating the P-control station providing sufficient inertia by maintaining the DC voltage stability. It's important to note that large transient disturbances in P-control station as well as in AC grid (e.g. a 3-phase faults near converter station) demand a very fast response from U_{dc}-control station to avoid any un-acceptable DC voltage excursion outside the normal voltage range. The DC voltage may become too high or too low depending on if the P-control station is in inverter or rectifier operation prior to disturbances. If the DC voltage is too high, it could hit the limitation of main circuit equipment and protection would trip converters. If the DC voltage is too low, it would lead to converter being not able to generate the desired AC voltage which either leads to un-controlled current or negative impact on the AC side.

Fig. 6 shows as an example of an HVDC interconnector under a 3-phase fault near the P-control station. The connected AC grids on both stations are relatively weak (SCR=4). The U_{dc}-control station with grid forming capability and two different inertia constants are considered: blue curves are obtained from the maximum inertia which the HVDC system is permitted (H_{DCN}), whereas the red curves are obtained with the inertia increased by a factor of 2 (from H_{DCN}). Fig. 6 shows that it is not possible for the DC link to recover after this disturbance if the U_{dc}-control station has higher inertia than permitted, as the U_{dc}-control cannot react fast enough to bring down the DC voltage below the trip level. The permitted inertia (H_{DCN}) is typically below 0.3 s.

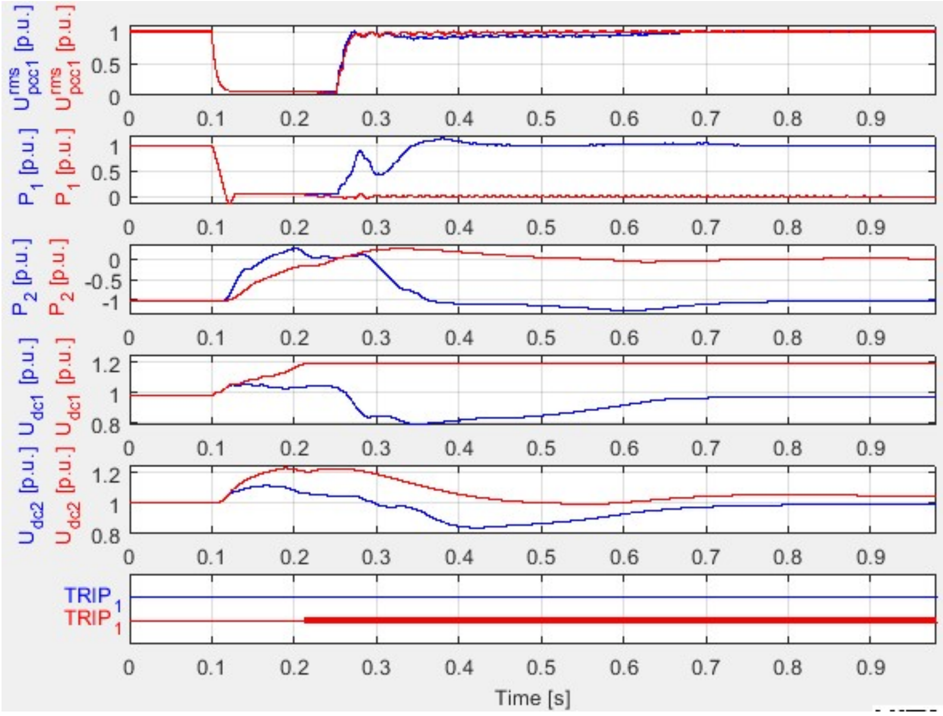

Fig. 6: 3-phase to ground fault near the P-control station. Subplot 1: PCC voltage, subplot 2: active power at PCC of P-control station, subplot 3: active power at PCC of P-control station, subplot 4: dc voltage of P-control station, subplot 5: dc voltage of U_{dc}-control station, subplot 6: trip indication for P-control station.

In the VSC-HVDC application of connecting offshore wind farm, inertia support for onshore grid from the onshore converter will be quite limited even if the onshore converter control is designed with grid forming capability. Suppose that the wind turbines operate in the traditional way i.e., grid-following mode. In that case the offshore converter of HVDC controls the voltage and frequency of the offshore grid and the onshore converter control the DC link voltage. With this control, the wind turbine generators in grid-following mode with maximum power point tracking (MPPT) and the active power generated will be immediately transmitted to onshore grids. This means that HVDC can only deliver the power generated by wind farms, or in another word offshore converter can be considered as a constant power source that does not contribute to U_{dc}-control. Thus, the task of maintaining the DC system voltage stability (or keeping the active power in balance) can only be achieved by the onshore station. On the other hand, grid forming behavior demands the onshore converter to supply/absorb the active power required by the AC grid depending on the type of transient events e.g., voltage angle jump due to trip of AC lines, generators, or loads. Obviously, there will be a conflict between “maintaining the DC voltage stability” and “grid forming behavior”. The possible consequences are that the DC voltage stability is jeopardized while providing high inertia support or maintaining the DC voltage stability and the inertia support gets diminished by the U_{dc}-control action. Evidence of that is provided in Fig. 7 where the considered SCR for the onshore grid is 20.

It can be seen from the figure above an additional active power is immediately injected in the grid by HVDC when the phase angle changes from 0 to -10 degree at t=0.1 sec. The active power infeed from offshore converter remains constant (3rd subplot) throughout the disturbance period. This means

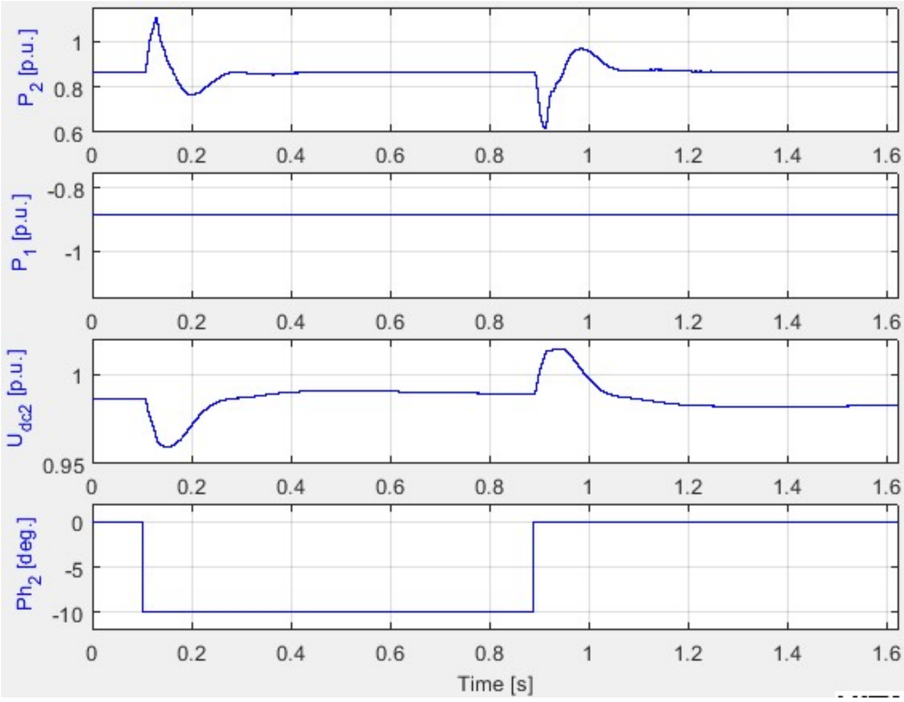

Fig. 7: Grid voltage phase jump of -10 degrees – onshore grid of a VSC-HVDC connecting offshore wind farm. Subplot 1: Active power at PCC of onshore converter, subplot 2: Active power at PCC of offshore converter, subplot 3: dc voltage of onshore converter and subplot 4: grid voltage phase (onshore grid represented as a Thevenin source).

that the energy is taken from DC link (or converter submodule capacitance and cable capacitance) and the DC voltage starts to fall quickly. Soon after that, the U_{dc}-control reacts to restore the DC voltage by taking the energy from the onshore grid. Eventually, the average power from HVDC onshore converter is maintained the same (as the pre-disturbance value) which means that the active power support diminishes to zero. Had the DC control not reacted faster, the DC voltage would have gone so low risking the stability of HVDC link.

It's to be noted that for VSC-HVDC connecting of offshore wind farms, a possible way to provide inertia/frequency support for a longer period without jeopardizing the DC link stability is to install an additional energy storage in the onshore converter on DC side. The other option is to have grid forming capability in wind turbines and operate them below the MPPT with a headroom (impact on cost needs be evaluated). In that case the offshore HVDC converter can operate in U_{dc}-control mode (in grid following mode) and onshore converter operates in P-control mode (in grid forming mode). The energy required for onshore grid support can be extracted from wind turbines if wind is available.

Conclusion

A brief review on the requirements related to grid-forming behaviors in existing Grid codes/standards has been made. Challenges from some of the requirements are discussed. Via simulation examples, it is shown that:

- A very limited inertia support can be provided by the converter in U_{dc}-control mode for HVDC inter-connection applications.
- Diminished inertia support from onshore converter in U_{dc}-control mode for HVDC offshore wind power integration.
- Inertia support can be shaped according to requirement by the converter in P-control mode under the pre-conditions of sufficiently fast U_{dc}-control in other station and the AC network connected to U_{dc}-control station can tolerant transient power variation.

- High inertia by the converter in P-control mode may sacrifice traditional functions such as EPC, POD, etc.

Therefore, there is a need for further joint efforts from both TSOs and vendors to reach a common understanding so that unharmonized requirements are removed to avoid unnecessary problems or risk of worsening performance in comparison with the existing HVDC design.

Appendix

The simulation throughout the paper has been implemented in PSCAD/EMTDC using the system parameters detailed in Table I.

Table I: System parameters

Parameter		Value
Point-to-point HVDC link (asymmetrical monopole)	$U_{ac,rated}$	400 kV
	P_{rated}	1000 MW
	$U_{dc,rated}$	525 kV
	f_0	50 Hz
HVDC connected OWF (symmetrical monopole)	$U_{ac,rated}$	400 kV (onshore)
	P_{rated}	900 MW
	$U_{dc,rated}$	$\pm$320 kV
	f_0	50 Hz

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