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# Dynamics and control of Multi-Terminal High Voltage Direct Current networks for integration of large offshore wind parks into AC grids

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**SUMMARY**

The integration of larger and larger amounts of wind power is a major target of the European Union, however it represents a challenge for power system planning and operation.

The paper analyses stability aspects concerning the operation of Multi-Terminal HVDC networks connecting offshore wind farms to the AC systems. Modelling issues are tackled, relevant to control schemes needed for a secure operation of the overall AC-DC system in case of contingencies both on the AC side and on the DC side.

First, power flow control principles are described for the "backbone" HVDC grid topology (consisting of point-to-point connections between offshore wind farms and mainland grid, linked by a DC connection).

Second, dynamic converter models suitable to investigate electromechanical transients are illustrated and some stability issues connected to the network performance under contingencies/disturbances are pointed out. The need both to survive severe disturbances and to provide ancillary services calls for the adoption of advanced control schemes.

Some simulations are described to illustrate the behaviour of the mixed AC-DC network under contingencies concerning both faults on DC cables and faults on AC lines.

The work has been carried out within Working Package 5 of EU co-founded Project TWENTIES.

**KEYWORDS**

**HVDC – High Voltage Direct Current – offshore wind farms – stability - control**

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## 1 INTRODUCTION

The integration of larger and larger amounts of renewable power (especially wind) is a major goal of the energy policies in the European Union (EU) [1]. A significant contribution to wind generation capacity increase is expected from offshore installations [2]-[3]. To this aim, innovative HVDC technologies may provide cost-effective solutions for the connection of large, remote offshore wind farms to the continental AC grids [4]. The perspective is indeed to realize Multi-Terminal, possibly meshed, offshore HVDC grids [5]-[6], hereafter referred to as DC Grids (DCG).

DCG must assure flexibility of operation, which can be achieved by integrating the wind power transfer capability (including mitigation i.e. offshore wind power fluctuations must be suitably absorbed by onshore converters), the interconnection function (i.e. the use of the Multi-Terminal HVDC grid for exchanging power between areas and managing possible congestions on AC side), and the ancillary services function (e.g. voltage support, frequency support as well as black start capability). By this vision, overall operational costs might decrease while at the same time complying with possible future “DC grid code” requirements.

The required flexibility can be achieved by the HVDC technology [4]-[6] based on forced-commutated devices, Voltage Source Converters (VSCs). In fact, compared to the classic HVDC technology based on Line Commutated Converters (LCCs), VSC-HVDC technology does not suffer from commutation failures during the reduction of AC voltage in case of AC faults, it offers enhanced control performances (e.g. reactive power control, black start capability) and other features (capability to connect to weak AC networks, simpler extension to MTDC network, compactness, modularity) that minimize environmental impact and construction costs, two main issues for the design and the operation of an (offshore) DC grid. However, VSC-HVDC still suffers from higher losses and presents higher control complexity.

Among the main barriers to the deployment of DCG one can find the need to introduce high voltage DC breakers and the demanding requirements of DC protection systems (especially regarding speed and selectivity). This is a really new challenge compared to existing point-to-point HVDC connections, where the radial topology allows attributing the DC fault clearing function to the protection systems on the AC side. Very little experience is available today on the technology for high voltage DC breakers [7], while DC protection schemes are still being investigated. For the time being, the complete chain including the detection / selection / clearing / robustness with appropriate dynamics to avoid any instability spreading at the interconnected DC / AC power system level is still to be designed.

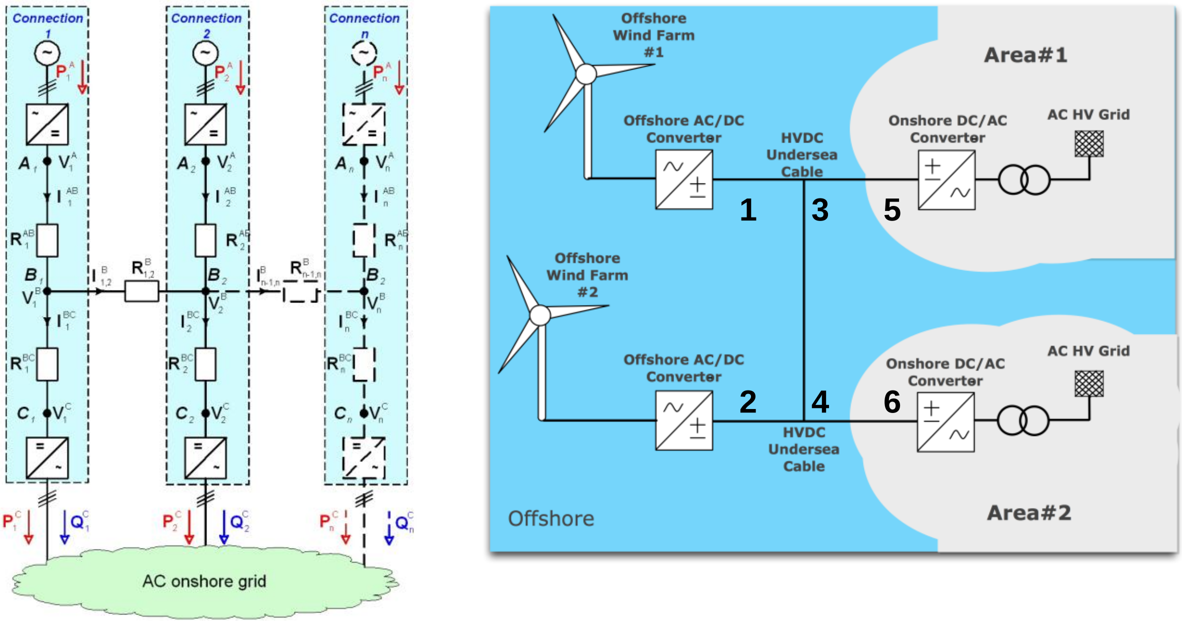
Flexibility of operation is limited by static and dynamic stability constraints deriving from the DCG in itself and from the interactions with the AC grid(s), which may affect overall system security. The requirement is to prevent any kind of instabilities and cascading outages of the interconnected DCG / AC mainland grid) which may result from contingencies either in the DC or in the AC grids. To this aim specific DCG control systems must be realised, properly coordinated with those of the AC systems and of the offshore wind farms. The DCG presents significant differences with respect to AC systems. More control variables are available, but the overall operational complexity is higher and increased by wind power uncertainties. Stability phenomena exhibit themselves in a different way with respect to AC transmission, which requires different approaches in the design of control functions. Similarly, it is foreseeable that significant training will be needed by the operators to understand and correctly operate the DCG, as well as strong coordination among TSO’s.

The paper presents an on-going work on the design of DCG control functionalities for normal and contingency situations, in view of providing operational flexibility and ancillary services while guaranteeing overall DC-AC system security. The work is performed within the framework of the UE co-funded TWENTIES Project [8]. The paper is organised as follows: Section 2 proposes a first realistic topology for future DCGs and presents steady state principles of the control strategy for an MTDC network. Section 3 discusses issues related to the DCG stability and presents the basic blocks of dynamic model for the integrated AC-DC network. Section 4 describes the test system and some preliminary simulation results. At last, some conclusions are drawn in Section 5.

# 2 GRID TOPOLOGY AND STEADY-STATE CONTROL

The DCG connects remote wind farm AC islands to one or more mainland AC grids in one or more points of common coupling (PCCs). Various topologies have been already discussed for offshore DC grids, from simple academic to rather generic and complex ones [9]. Yet, most of them take implicitly for granted the fact that offshore grids would be raised from scratch regardless of pre-existing connections to the shore.

Contrary to this, a more realistic approach when designing a DC grid is to consider that since large investments come into play, a DC network would most likely be built up step by step, leaning on existing DC connections. Hence, assuming the existence of a point-to-point DC link to transmit offshore wind energy, a simple yet flexible structure was proposed in the frame of Work Package 5 of the TWENTIES project, which is illustrated in this paper. The generic topology described hereafter is referred to as **the "backbone" topology**, where direct point-to-point connections of offshore wind farms are linked by DC ties as sketched in Figure 1 a).




a) b)

**Figure 1: a) Steady-state model of backbone grid topology linking two direct connections (solid line), and with possible extension (dashed line); b) Scheme of a DCG connecting two offshore AC islands (left side) with two mainland AC grids (right side)**

This topology can describe a wide variety of layouts, depending on the possible values combinations for the cable resistances, and converters or wind farms ratings. Basically, any kind of "backbone" scheme with different numbers of onshore and offshore converters can be represented using this convention. From a geographical standpoint, this corresponds to the installation of wind farms along a coast shore (similar to the Atlantic Wind Connection project [10], for instance).

For the remaining of the paper, this layout will be discussed in the case of two wind farms connections (n = 2), that is with two onshore converters and two offshore ones; this topology is hereafter called the **"H" topology**, and it is sufficient to show a broad range of features without loss of generality.
A simple scheme of this grid is reported in Figure 1b). The basic subsystems composing the overall AC/DC system are: the multi-terminal DC network (including DC cables and substations), the onshore grid side converters (Grid-Side VSC, GS-VSC), the offshore wind farm side converters (Wind Farm VSC, WF-VSC), the wind farms (WF), the AC grids (both offshore and onshore).

The offshore (WF-VSC) stations are operated to control the offshore AC island frequency and voltage magnitude. Consequently, they have no direct control on DC voltages (same as for the backbone nodes, which are passive ones). The onshore converters will most likely be responsible for onshore AC voltage support (or reactive power injection) and DC voltage control [11].

Early work concerning theoretical DC grids considered one single HVDC station would act as a slack bus to absorb and regulate all power variations of the whole DC grid. This approach is usual in point-to-point HVDC links, where one converter controls the voltage and the other the current (or power). However, when applied to DC grids, it leads to significant limitations:

- The rating of this specific converter must be such that it can handle all power changes occurring across the DC grid. The same consideration applies for the nearby AC grid it is connected to. These issues can involve the oversizing of the converter station with increase of construction costs.
- In case of a contingency occurring in this station (or on its connecting cable), there has to be anyway at least another converter on which the voltage regulation can be switched (though not necessary activated).

These considerations lead to the conclusion that DC voltage regulation function should be shared among several onshore converters. Thus, a DC Voltage-Power (VP) droop solution is generally proposed [6]. This control imposes a linear relationship between the active power exchanged with the grid and the voltage at the DC bus. Major advantages of this solution are: the simplicity of the high level control principle for converters of different power capability (and from different manufacturers) to be operated together on a DC grid; the increased autonomy of converters and their poor dependence on a master control; the improved survivability of DCG to the outage of a converter. Within the TWENTIES project, an innovative control strategy of the GS-VSC, specifically devoted to the backbone topology, is under development to achieve higher DCG control performances.

# 3 DYNAMIC PHENOMENA AND CONTROLS

The DCG presents complex interactions with the different AC systems it is connected to, namely WF islands and mainland grid. In designing DCG control and protection systems, coordination is fundamental in order to ensure overall system stability. Indeed, disturbances may propagate through the DCG from the mainland AC system to the offshore wind generators and vice versa.

Disturbances like the loss of onshore VSCs or AC faults on mainland grid may cause severe active power imbalances between the sending end converters and the receiving end converters of DCG, raising security issues. For example, when the AC grid experiences an AC fault near a GS-VSC, the voltage of the GS-VSC’s PCC drops. The power delivered to the AC grid will also drop, and the converter reach its limits of injected current. Once the current reaches the limit of the converter, the GS-VSC will lose its ability to control the DC voltage. The excess of power produced by the WF is absorbed by the capacitances of the DCG causing overvoltages within few milliseconds in the DCG itself [9]. To relieve the overvoltage, WF-VSCs will change into a DC voltage control mode, which will rapidly reduce the AC side voltage to limit the power injection into the DCG. An abnormal AC voltage might cause the tripping of the wind turbines due to low voltage protection [12]. Thus, WF-VSC control during AC grid faulted condition should be coordinated with the low voltage fault ride through (LVRT) capability of the wind turbines. Also, the reduction of AC voltage of the wind turbines will result in generator over-speeding. In this case, to balance the power of the wind turbines, a load resistance, such as crowbar, may be switched on to rapidly release the extra energy and the slower pitch angle regulation can subsequently be used to reduce the captured wind power [13].
Another issue related to the interaction between AC and DC systems is that the presence of VSCs, connected to AC grid and endowed with voltage support control systems, affects the AC voltage profile during AC faults, thus AC protections may require adaptations and the introduction of specific defence systems.
The following subsections describe the basic control functions of the DCG and of the offshore WF.

### 3.1 Wind farm side converter

The WF-VSC has the task of controlling the AC voltage (magnitude and phase angle) and frequency at the offshore PCC. A current-controlled Park's transformation based system (see Figure 2) can be adopted to perform WF-VSC control.

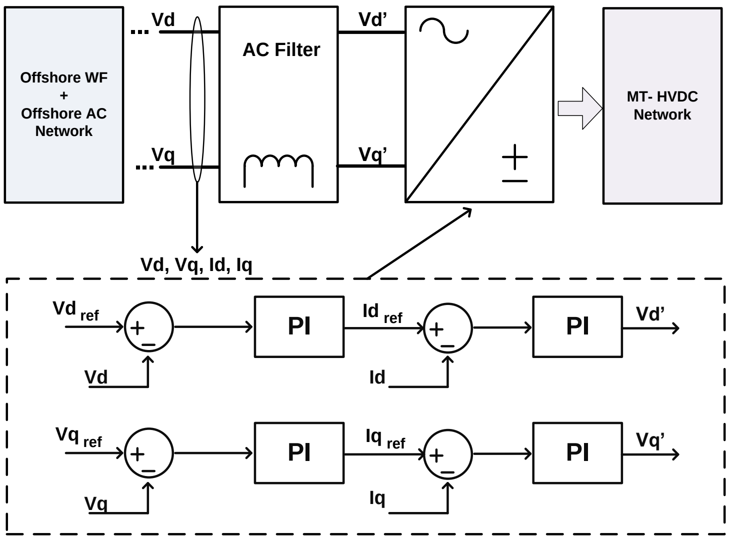



**Figure 2: Current controlled system based on Park's transformations for WF-VSC control**

In case of faults in the offshore AC islands, the VSC provides a contribution to the fault current. The current injection must be restrained however, in order not to damage the converter itself. Thus, the VSC control includes a current limitation function.

### 3.2 Grid-side converter

The proposed control scheme for GS-VSC is aimed at imposing a linear control law between the DC voltage and the active power exchange, and at regulating the AC voltage magnitude.
Even if the basic VP droop and $V_{ac}$ control exhibits satisfactory performance in normal operation (e.g. in case of wind power fluctuations), it has some drawbacks in case of disturbances of the AC grid. In fact, in case of AC faults close to the PCC of the GS-VSC, the PI control aimed at regulating the voltage magnitude at the AC bus may determine a very large (though short) overload of the converter, which is unacceptable under a practical point of view. Thus, the GS-VSC must perform current limit control similarly to the WF-VSC [14].

### 3.3 Wind generators

Two wind generator technologies are considered, i.e. Doubly-Fed Induction Generator (DFIG) and Permanent Magnet Synchronous Generator (PMSG), the latter being a particular case of Full-scale frequency Converter Synchronous Generator (FCSG). Both DFIG and PMSG are interesting, because:

- DFIG is currently the most widely used machine for wind generation. It has the largest size (2-6 MW) among wind generators, and it is most cost-effective. DFIGs are endowed with an internal VSC converter of small size (about 40% of the machine size), which allows a significant operational speed range in order to optimally exploit different wind conditions while limiting the equipment cost
- PMSG technology is rapidly evolving, the machine size (currently about 5 MW) could shortly overcome that of DFIG. PMSG is more costly than DFIG because of the full size converter, but it can exploit a wider range of wind speed conditions. Being a brushless and gearless machine, the PMSG may require less maintenance than DFIG, which could be preferable factor in offshore environment. The higher rating of converters is currently associated to a higher failure rate, but this is expected to decrease in the future.

Wind generators are characterized by a traditional control strategy aimed at maximising the power extracted from wind (further controls can be superimposed in order to provide services and to contribute to system stability). A slow and a fast controller respectively act on the rotor and the electrical machine respectively. For example, for DFIG technology, the first controller consists in the speed and power control of the rotor whereas the second consists in the active-reactive power PQ control on the rotor-side converter and in a DC voltage/power factor control scheme applied to the grid-side converter of the DFIG connected at the rotor side.

# 4 SIMULATION EXAMPLES

After a brief outline of the test system, this section presents some simulation results aimed at illustrating the dynamic behaviour and the need for advanced controls and possible SPS schemes to survive severe contingencies.

The AC/DC grid set up for the simulations [15][16] consists of two offshore wind farm AC islands, a DCG in bipolar configuration, and a mainland AC grid. It is an H-shaped DCG like the one in Figure 1b) where Areas 1 and 2 belong to the same AC mainland grid. All the DC cables are endowed with a smoothing reactor at each terminal.

All the DCG converters are assumed to be realised with VSC technology and the base case load flow is characterised by a symmetric operation of the DCG: the two GS-VSCs have the same AC voltage setpoints and V-P droop parameters; the WF-VSCs have equal AC voltage setpoints.

The section illustrates few samples of the simulations performed on the dynamic model described above. In particular the focus in on the following contingencies:

- Faults on AC mainland grid
- Faults on the DC network

## 4.1 AC faults

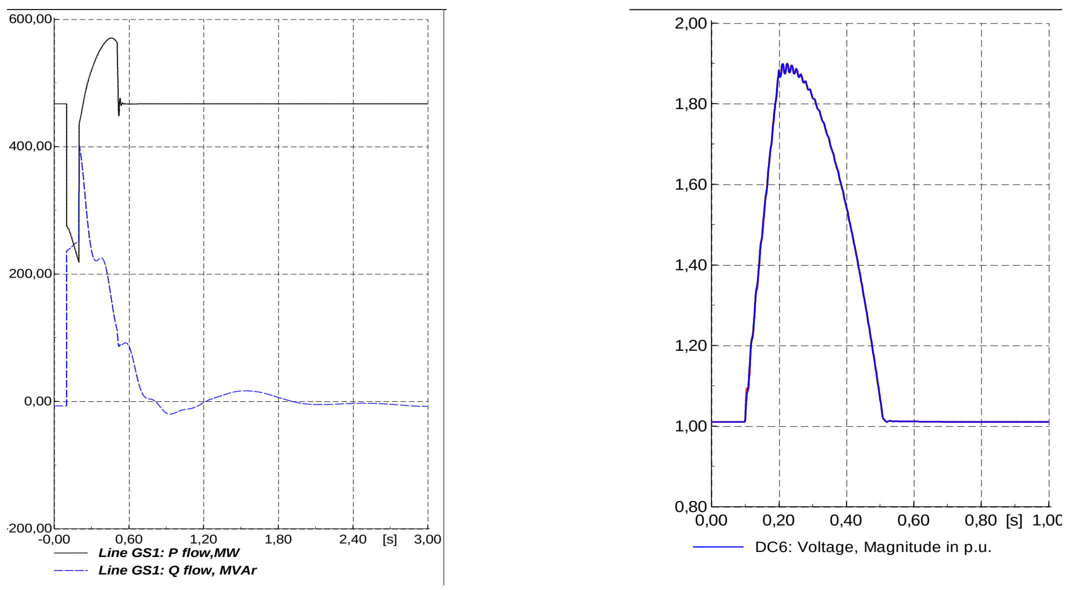
Coping with AC mainland contingencies calls for:

a) additional controls on the DCG converters to avoid dangerous DC overvoltages
b) coordination actions between the settings of distance protection systems of AC lines on the mainland grid and the operating point of the DCG (including the control mode of GS-VSCs, the actual wind power generation from WFs)

As recalled in Section 3, the occurrence of a fault close to the PCC of a DCG may endanger the overall system stability as the temporary drop of active power evacuated by the GS-VSCs determines a significant power mismatch between the power generated by the WFs and the power delivered to the mainland grid, which in turn causes large overvoltages on the DC grid. Figure 3 shows the effect of a 100 ms three-phase auto-extinguishing fault on a 400 kV line close to the PCCs: Figure 3a) shows the active and reactive power outputs of GS-VSC1 which undergoes the intervention of the current controller during the fault on period. Moreover, it can be noticed from Figure 3b) that DC voltage would reach 1.8 p.u., an unfeasible value for DC grid operation. DC protection systems would trip the DCG thus causing a severe disturbance in the mainland grid.

The overvoltage occurrence in the DCG is independent of the WF generator technology since it occurs due to the power imbalance provoked by the incapability of VSC on delivering active current during AC low voltage periods. However, it is necessary to guarantee that the overvoltage does not exceed a certain value (maximum admissible voltage value). To design a device able to handle the power imbalance it is necessary to know the equivalent capacitance value of a given grid as well as the expected non-delivered power (due to AC fault occurrence) and finally, the maximum admissible DC voltage value. In general, the countermeasure to avoid overvoltage occurrence should act within tens of milliseconds to be effective.

The most effective way to promote the power balance in the DC grid within the available time consists in accommodating/dissipating the non-delivered active power in a chopper resistance. This device consists in a power electronic converter that controls the amount of power that is dissipated in a resistor, promoting the DC power balance thus maintaining the DC voltage within the admissible range.



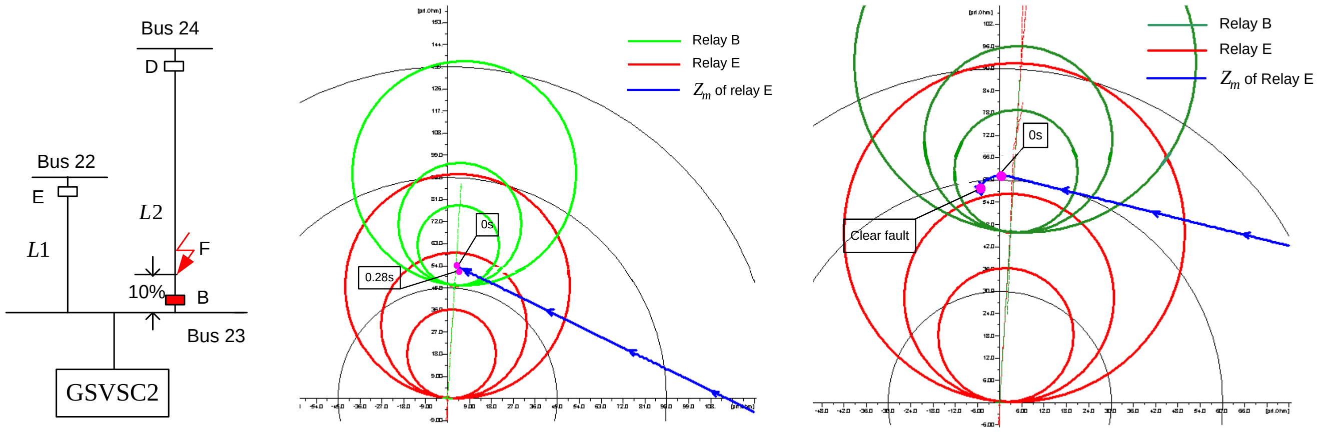

a) b)

**Figure 3: a) Active and reactive power output of GS-VSC 1 with intervention of the current limiting block; b) Voltage at a DC bus**

As an illustrative example for point b), a short circuit (SC) fault is simulated in the AC system. At *t* = 0 s, a SC fault F located at 10% of a line from one of the PCCs of the DCG (Bus 23) is started, as shown in Figure 4(a). According to the relay settings discussed, fault F is in the range of relay B Zone 1 and relay E Zone 2. Zone 1 of relay B is assumed to have failed, namely, relay B should have tripped but it did not. The simulation results for the analysed cases - DCG connected and DCG disconnected to the AC system – are respectively shown in Figure 4(b) and Figure 4(c), where red cycles are the operation characteristics of relay E, the blue line is the trajectory of the apparent impedance viewed by relay E.

In Figure 4(b) the Zone 2 fault is cleared at a Zone 2 clearing time of 0.28s, including the time delay setting of relay E (0.25s) and the protection operation time (30ms).

In Figure 4(c), under the condition that the Zone 1 tripping of relay B does not occur, the Zone 2 SC fault is seen in the range of Zone 3.




a b) c)

**Figure 4: Diagrams: a) Line fault diagram for a fault at the PCC between DCG and AC system. b)-c) Apparent impedance viewed by Relay E in R-X plant: (b) without converters connected to bus 23, (c) with GSVSC2 at bus 23**

It can be thus noticed that in the AC grid with DCG the voltage support coming from GS-VSC reactive power control determines a voltage at PCC higher that the voltage without DCG. Correspondingly, the current viewed by relay E with DCG is lower than the one without DCG. This leads to an over-estimated fault distance due to the distance protection scheme. The Zone 2 fault F is incorrectly judged to be in the range of Zone 3 by relay E on the AC grid with DCG. It is a classical case of reactive current injection increasing the measured distance by a remote relay, or in other words shortening the extension of Zone 2 of that relay.

It is risky for a Zone 2 fault to be viewed as a Zone 3 fault. As a consequence and if the protection scheme is only based on distance protections without breaker failure management or other types of protection (differential protection, directional protection), the fault clearing time will be delayed. A longer fault clearing time will reduce the stability margin of the power system.

Moreover, the example above deals with a three-phase fault. Single-phase faults are more complex to consider, depending on the control loops, the converter transformer windings (Y or Delta) and neutral earthing, even if the consequences in terms of stability are smaller.

### 4.2 DC faults

In this simulation at t = 0.1 s a permanent pole-to-ground fault is applied on the positive pole of the DC cable 3-5 (see bus numbering in Figure 1b). The simulation simulates the “theoretical” behaviour of the system without taking into account the intervention of protection systems (which would trip the faulty element) with the aim to highlight an interesting aspect of this fault typology, concerning the interaction between AC and DC systems: the GS-VSCs (modelled as 2-level PWM converters) provide only transient contributions to the fault current, i.e. the AC mainland grid does not provide a permanent contribution to the fault current, as can be noticed in the bottom left diagram of Figure 5 which reports the AC current on the GS-VSC1: its steady state value does not change after the fault application.

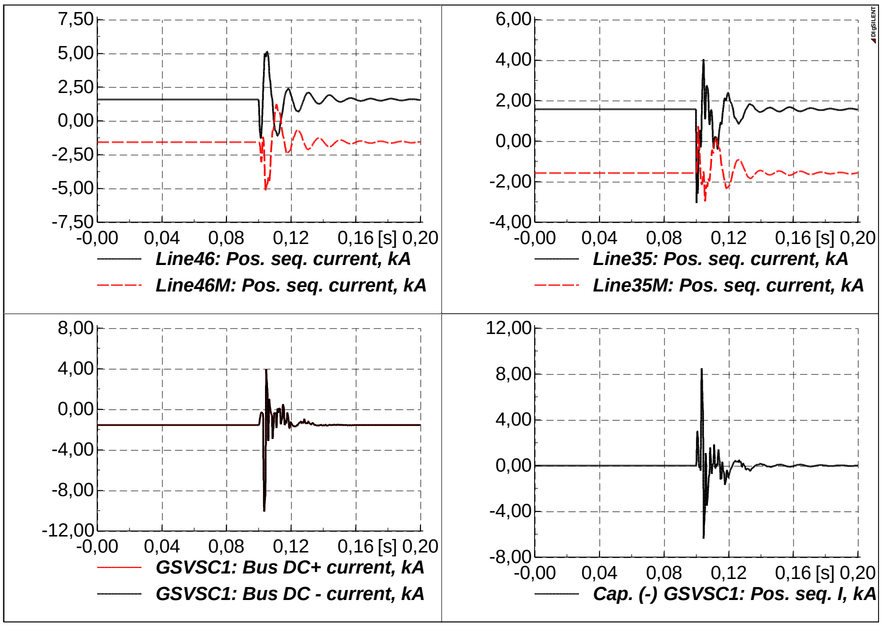



**Figure 5: Currents on the cables between nodes 3 and 5, and between 4 and 6 (top diagrams), currents flowing on the positive and negative poles of GS-VSC 1(bottom left), current through the mid-point capacitor at bus DC5(-) close to GS-VSC 1 (bottom right)**

## 5 CONCLUSIONS

The paper has presented some results of the on-going activities, performed within Working Package 5 of FP7 EU co-founded Project TWENTIES and related to the modelling and the simulation of multi-terminal HVDC networks to integrate large amounts of offshore wind power into the AC bulk power system.

VSC control laws must assure flexible operation, which can be achieved by integrating different functions (wind power transfer, interconnection, and ancillary services).

Security must be specifically addressed, to prevent instabilities and cascading outages of the DCG and possibly also of the mainland AC grid due to contingencies affecting either the DC or the AC grids. In particular, in a deterministic approach to security assessment, the N-1 criterion may need to be fully redefined on the DC side and correlated with System Protection Schemes.

Simulations point out that the design and development of **DC protection systems** (against DC and AC faults) is a challenge not only because of the component protection requirements, but also because of system stability and security requirements. Hence, **coordinated controls** must be applied to the DCG, the offshore wind farms, and the mainland AC grids. To this regard, controls based on local measurements (like the VP droop control on GS-VSCs) should be preferred to centralised control schemes with significant fast communication requirements.
In particular, faults on the AC mainland grid and on the DCG may cause unacceptable overvoltages in the DC grid itself, which must be faced by deploying **Fault Ride Through controls**. Moreover, GS-VSC reactive power controls affect the AC voltage profile during AC faults, possibly leading to miscoordination of AC distance protections: thus, **AC protections** may require adaptations, also at the design stage, and the introduction of specific defence systems.
Supplementary local control loops at HVDC-VSC stations and at offshore wind farms may allow DCGs to provide frequency support services to onshore mainland systems.
On-going activities are addressing an integrated control and defence framework for stability and ancillary services, involving DCG, wind farms and the AC mainland grid.

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