PROMOTioN
PROGRESS ON MESHED HVDC OFFSHORE TRANSMISSION NETWORKS

Deliverable 1.5: Quantification of requirements

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DISCLAIMER

The objective of this document is to specify requirements for different technologies to be developed within the boundaries of the PROMOTioN project. This document has no formal legal status other than a research document that aims at giving comprehensive insight and starting points for work to be executed in other work packages.

This report has used the current ENTSO-E network code for HVDC connections as a starting point. This caused that some statements are formulated in a way which could be interpreted as (European) TSO-centric or even restrictive and misaligned with other project partners' interests.

Some of the contributing project partners believe requirements formulated as '*a must*', potentially limit future innovative solutions or might inhibit the most socio-economic technology. These partners suggest 'may'-formulations to be more appropriate. Given the uncertainties associated with future DC grids and the amount of their potential technology solutions, it is in the best interest of the project progress to allow room in the interpretation of the formulation of requirements in the document.

LIST OF CONTRIBUTORS

Work Package 1 and deliverable 1.5 involve a large number of partners and contributors. The names of the partners, who contributed to the present deliverable, are presented in the following table.

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CONTENT

1 AN INTRODUCTION TO THE DOCUMENT

This document presents Deliverable 1.5 (D1.5) of Work Package 1 (WP1) of the PROMOTioN project. It contains definitions of which requirements are quantifiable and presents a list of the quantified requirements[2] of a Meshed Offshore Grid (MOG). The list is based on the qualitative requirements that were agreed in Deliverable 1.1 (D1.1) of WP1.

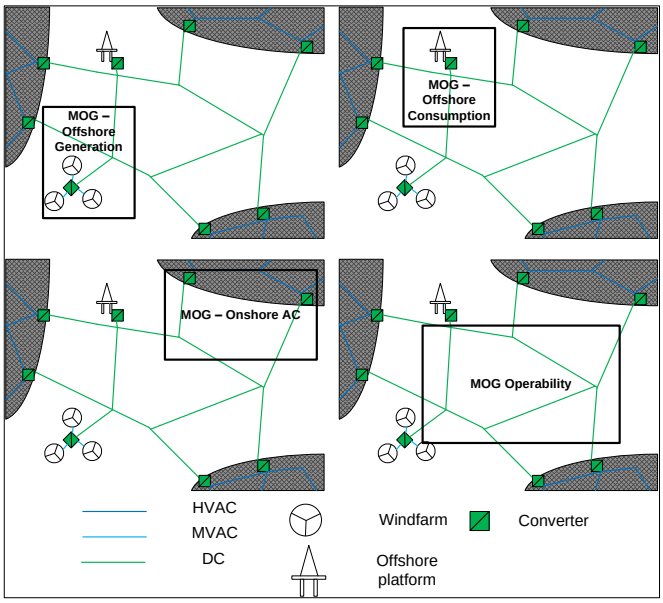

Figure 1 – Interfaces used as document structure

In D1.1 four overlapping interfaces (Figure 1) were defined to structure the document. The specific interfaces have requirements which guarantee the system requirements.

- **MOG – Onshore AC interface**: which puts constraints on the tolerable variations of the power output and quality, which imposes requirements on the MOG. Here the ENTSO-E HVDC grid code (NC HVDC) is taken as a starting point.
- **MOG – Offshore generation interface**: which puts requirements on the power output of offshore AC generation. Here the ENTSO-E code on Requirements for Generators (NC RfG) as well as the NC HVDC are used as a starting point.
- **MOG – Offshore consumption interface**: Which describes possible connections to offshore consumers. Connecting demand offshore is not the main purpose of the MOG, but could contribute to its attractiveness in certain cases. Since in D1.1 no specific requirements for offshore load were developed as possible connections will be evaluated on a case-by-case basis, quantification of requirements is not defined.

[2] The stated requirements are related to the actual snapshot of the development. The stated requirements are therefore preliminary and can be understood as a starting point for the development process and have to be checked and updated regularly.

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- **MOG Operability interface**: describes the requirements for steady state operation, operation of the DC grid and requirements to protection systems of the MOG. Jointly these overlapping interfaces cover all technical aspects of the MOG.

Since this deliverable depends heavily on the NC HVDC it is important to note that NC HVDC focuses on DC transmission grids' point to point connections, as well as extensions to multi-terminal radial connections. Meshed DC grids and DC collection grids are out of the scope of this network code. It is envisaged that meshed DC grids could gradually emerge for some applications in the future but this technology will need time to develop. Therefore meshed DC networks are considered out of the scope of the present NC HVDC, with possible inclusion in future amendments once the technology matures. Future revisions of the NC HVDC are expected to bring a meshed grid forward as the DC grid technologies move into implementation. Therefore this Deliverable also aims to identify where deviations are necessary for a MOG to develop, which are addressed in the discussion paragraph of each chapter.

Some of the requirements proposed in D1.1 are not quantifiable, or difficult to quantify at this stage of the PROMOTioN project. This applies mainly to the requirements listed in Chapter 3, Chapter 6 and Chapter 8 of D1.1 which are about the functional system requirements, offshore consumption and the non-functional requirements, respectively. A brief explanation on why these requirements at the present stage are not quantifiable is given in the respective chapters.

The structure of D1.5 and, in particular, the numbering of the Chapters in this report is orientated at D1.1. For every item the qualitative requirement from D1.1 is listed followed by the quantification as part of D1.5. Whether the requirement is qualtitative from D1.1 or quantitative from D1.5 is presented in the margin as follows:

D1.1 Qualitative requirement from D1.1

D1.5 Quantitative requirement from D1.5

In case the item couldn't be quantified the item is listed as one of the three following statements, sometimes followed by example values.

- Not quantifiable: An item that is qualitative by its nature and can therefore not be quantified
- Quantifiable but not available yet: An item that could be quantified but is not quantified in grid codes
- Quantifiable but a project specific requirement: An item that could be quantified but is based on a case by case basis and therefore not generalistic.

For the creation of this deliverable all project partners were consulted via conference calls, digital feedback rounds and expert meetings. This has led to a Deliverable, which has gone through a number of iterations, which presents aligned content, and builds on the experience of the partners of the PROMOTioN project. It is important to note that this document is not a legal document but a research document in order to give a comprehensive insight in which requirements are going to be used by the different WPs.

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2 LIST OF DEFINITIONS AND ABBREVIATIONS

The list of definitions here is based on the the NC for HVDC connections and the NC for Requirements for Generators. It is by no means exhaustive, but serves as assistance to the reader.

2.1 DEFINITIONS

1. '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;
2. '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;
3. 'HVDC converter station' means part of the HVDC system which consists of one or more HVDC converter units installed in a single location together with buildings, reactors, filters, reactive power devices, control, monitoring, protective, measuring and auxiliary equipment;
4. 'maximum HVDC active power transmission capacity' ($P_{\max}$) means the maximum continuous active power which an HVDC system can exchange with the network at each connection point as specified in the connection agreement or as agreed between the relevant system operator and the HVDC system owner;
5. 'minimum HVDC active power transmission capacity' ($P_{\min}$) means the minimum continuous active power which an HVDC system can exchange with the network at each connection point as specified in the connection agreement or as agreed between the relevant system operator and the HVDC system owner;
6. 'HVDC system maximum current' means the highest phase current, associated with an operating point inside the $U - Q/P_{\max}$ - profile of the HVDC converter station at maximum HVDC active power transimission capacity;
7. 'power – generating module' means either a synchronous power – generating module or a power park module;
8. 'power park module' or 'PPM' means a unit or ensemble of units generating electricity, which is either non – synchronously connected to the network or connected through power electronics, and that also has a single connection point to a transmission system, distribution system including closed distribution system or HVDC system;
9. 'offshore power park module' means a power park module located offshore with an offshore connection point;
10. '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;
11. 'offshore grid connection system' means the complete interconnection between an offshore connection point and the onshore system at the onshore grid interconnection point;

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12. 'onshore grid interconnection point' means the point at which the offshore grid connection system is connected ot the onshore network or the relevant system operator;
13. $'U - Q/P_{\max}$ - profile' means a profile representing the reactive power capability of a power – generating module or HVDC converter station in the context of varying voltage at the connection point;
14. 'fault – ride – through' means the capability of electrical devices to be able to remain connected to the network and operate through periods of low voltage at the connection point caused by faults;
15. 'synthetic inertia' means the facility provided by a power park module or HVDC system to replace the effect of inertia of a synchronous power – generating module to a prescribed level of performance;
16. 'frequency control' means the capability of a power – generating module or HVDC system to adjust its active power output in response to a measured deviation of system frequency from a setpoint, in order to maintain stable system frequency;
17. 'frequency sensitive mode' or 'FSM' means the operating mode of a power – generating module or HVDC system in which the active power output changes in response to a change in system frequency, in such a way that it assists with the recovery to target frequency;
18. 'limited frequency sensitive mode – overfrequency' or 'LFSM – O' means a power – generating module or HVDC system operating mode which will result in active power output reduction in response to a change in system frequency above a certain value;
19. 'limited frequency sensitive mode – underfrequency' or 'LFSM – U' means a power – generating module or HVDC system operating mode which will result in active power output increase in response to a change in system frequency below a certain value;
20. 'frequency response deadband' means an interval used intentionally to make the frequency control unresponsive;
21. 'frequency response insensitivity' means the inherent feature of the control system specified as the minimum magnitude of change in the frequency or input signal that results in a change of output power or output signal;
22. 'black start capability' means the capability of recovery of a power – generating module from a total shutdown through a dedicated auxiliary power source without any electrical energy supply external to the power – generating facility;
23. 'fast fault current' means a current injected by a power park module or HVDC system during and after a voltage deviation caused by an electrical fault with the aim of identifying a fault by network protection systems at the initial stage of the fault supporting system voltage retention at a later stage of the fault and system voltage restoration after fault clearance;

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2.2 ABBREVIATIONS

A list of abbreviations for the terms that are used in the document can be found in Table 1. They are based on D1.1 with a few additions.

Term	Meaning
NC HVDC	Network Code for the HVDC connections [1]
NC RfG	Network code for Requirements for grid connections of Generators [2]
ENTSO-E	European Network of Transmission System Operators for Electricity
HVDC	High Voltage Direct Current
MTDC	Multi Terminal DC
MOG	Meshed Offshore Grid
OTS	Offshore Transmission System
PPM	Power Park Module
OWF	Offshore Wind Farm
WTG	Wind Turbine Generator
WPP	Wind Power Park
FRT	Fault Ride Through
LVRT	Low Voltage Ride Through
FSM	Frequency Sensitive Mode
LFSM – O	Limited Frequency Sensitive Mode - Overfrequency
LFSM – U	Limited Frequency Sensitive Mode - Underfrequency
IGBT VSC	Voltage Source Converter (IGBT based) in text: VSC
HB-MMC	Half Bridge Modular Multilevel Converter
FB-MMC	Full Bridge Modular Multilevel Converter
LCC	Line Commutated Converter
DRU LCC	Diode Rectifier Unit, in text: DRU
SCR	Short Circuit Ratio
Thyristor LCC	Thyristor Line Commutated Converter
DCCB	DC Circuit breaker
ROCOF	Rate Of Change Of Frequency
PCC	Point of Common Coupling
SSTI	Sub-synchronous torsional interaction
N-1, N-k, k>1	Criterion used to express a measure of reliability/security (number of components that can fail without compromising the system)

Table 1 – Abbreviations

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3 FUNCTIONAL SYSTEM REQUIREMENTS

In D1.1 the following Functional System Requirements were defined:

- Transmission capacity requirements
- Interoperability
- Reliability
- Stability and Controllability

For this document these requirements are considered 'non-quantifiable'. The transmission capacity requirements are a result of the amount of installed offshore wind power and desired interconnection capacity among involved countries and therefore a political decision. Interoperability is a qualitative requirement. Reliability could be considered a quantifiable requirement, but it is not quantified at this stage of the project. It should be considered in the overall evaluation of the development of the meshed offshore grid. Stability and controllability are qualitative requirements.

In D1.4 scenarios are provided, including load and generation, that can be used as an input for simulations.

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4 MESHED OFFSHORE GRID – ONSHORE AC

4.1 INTRODUCTION

This chapter presents the qualitatitve requirements that were set in D1.1 and the quantification of these requirements. The Network Code on HVDC connections (NC HVDC) was selected as the starting point for the quantification process. Each requirement starts with the qualitative requirement from D1.1, after which the quantification is given if possible. The NC HVDC grid code was selected as a starting point for some items, although it does not take into account a Meshed Configuration (it assumes point to point connections). The chapter therefore ends with a discussion on additions that will have to be made for the purpose of a Meshed Offshore Grid, with quantifications if possible. Of course, any suggested changes to the NC HVDC will have to follow the regular code change procedures. In the discussion chapter there is also room for discussion about the direction in which values could develop over time. On a 10-30 year timescale certain parameters will not remain constant. The HVDC grid code frequently refers to 'the relevant TSO', this is left intact in this chapter, even though the nature of the entity responsible for these tasks for the MOG needs to be defined in Workpackage 7.

4.2 GENERAL REQUIREMENTS FOR HVDC SYSTEMS (ONSHORE HVDC CONVERTER STATIONS)

4.2.1 REQUIREMENTS FOR ACTIVE POWER CONTROL AND FREQUENCY SUPPORT

4.2.1.1 FREQUENCY RANGES

D1.1 The HVDC systems must be capable of operating within a specified frequency range. The frequency range values might vary between the different synchronous AC areas.

D1.5 The frequency ranges in Table 2 are based on the Network Code for HVDC connections, the Network Code for Requirements for grid connection of Generators and the Network Code on Demand Connection.

Frequency range	Time period of operation
47.0 Hz – 47.5 Hz	60 seconds
47.5 Hz – 48.5 Hz	To be specified by the relevant TSO but longer than 30 minutes
48.5 Hz – 49.0 Hz	To be specified by the relevant TSO but longer than 90 minutes
49.0 Hz – 51.0 Hz	Unlimited

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51.0 Hz – 51.5 Hz	To be specified by the relevant TSO but longer than 90 minutes
51.5 Hz – 52.0 Hz	To be specified by the relevant TSO but longer than 15 minutes

Table 2 - Complete table of frequency ranges and time period of operation for an HVDC system [1] [2]

4.2.1.2 RATE OF CHANGE OF FREQUENCY CAPABILITY

D1.1 The HVDC system must be capable of withstanding specified AC system frequency rates of change.

D1.5 If the network frequency changes with a rate up to ± 2.5 Hz/s the HVDC system must be capable of staying connected to the network and operate (measured at any point in time as an average of rate of change of frequency for the previous 1s). [1]

4.2.1.3 FREQUENCY SENSITIVE MODE (FSM) PARAMETERS

D1.1 The AC/DC converters of the HVDC system must be equipped with an independent control mode to modulate the active power output of the HVDC converter station according to the frequencies at all connection points of the HVDC system to maintain stable system frequencies and/or contribute to the frequency control of the AC system. The detailed operating principle, associated performance parameters and activation criteria of this frequency control must be specified.

The HVDC systems must be capable of operating in the following three control modes:

- Frequency Sensitive Mode (FSM)
- Limited Frequency Sensitive Mode – Overfrequency (LFSM-O)
- Limited Frequency Sensitive Mode – Underfrequency (LFSM-U)

The following parameters for these control loops are to be specified by the TSO, within certain bounds mentioned in the network code:

- Frequency response deadband
- Upward droop value
- Downward droop value
- Frequency response insensitivity
- Initial delay of activation

D1.5 When operating in frequency sensitive mode (FSM):

a) The HVDC system should be able to respond to frequency deviations in a connected AC network by adjusting the active power transmission as indicated in Figure 2 and in accordance with the parameters specified by each TSO within the ranges shown in Table 3.

b) The adjustment of the active power frequency response is limited by the minimum and maximum active power transmission capacity of the HVDC (in each direction).

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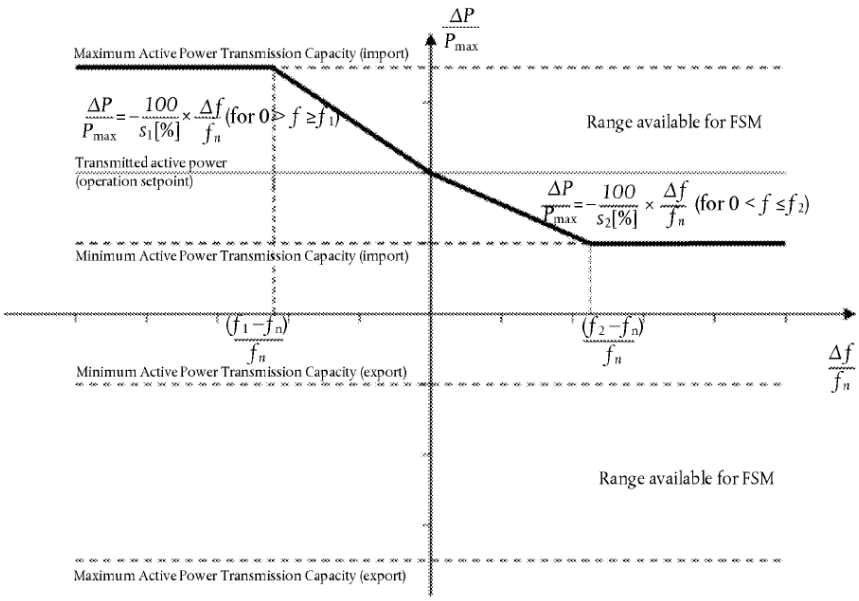

Figure 2 – Active power frequency response capabilty of an HVDC system in FSM [1]

Parameters	Values
Frequency response deadband	0 - ± 500 mHz
Droop s_1 (upward regulation)	Minimum 0.1%
Droop s_2 (downward regulation)	Minimum 0.1%
Frequency response insensitivity	Maximum 30 mHz
Maximum admissible initial delay t_1	0.5 seconds
Maximum time for full activation t_2 (unless longer times required by TSO)	30 seconds

Table 3 – Control loop parameters associated with FSM [1]

The equations linked with the active power frequency response capability are:

$$\frac{\Delta P}{P_{max}} = -\frac{100}{s_1[\%]} * \frac{\Delta f}{f_n}, \qquad \Delta f = f_1 - f_n, \qquad (for\ f_1 < f \leq f_n)$$

$$\frac{\Delta P}{P_{max}} = -\frac{100}{s_2[\%]} * \frac{\Delta f}{f_n}, \qquad \Delta f = f_2 - f_n, \qquad (for\ f_n \leq f < f_2)$$

c) The HVDC system shall be capable, following an instruction from the relevant TSO, of adjusting the droops for the upward and downward regulation, the frequency response deadband and the operational range of variation within the active power range available for FSM, set out in Figure 2 and more generally within the limits set by points a) and b).

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d) As a result of a frequency step change, the HVDC system shall be capable of adjusting active power to the active power frequency response defined in Figure 2, in such a way that the response is:
   i. As fast as inherently technically feasible
   ii. At or above the solid line according to Figure 3 in accordance with the parameters specified by the relevant TSO within the ranges according to Table 3.
      - The HVDC system shall be able to adjust active power output ΔP up to the limit of the active power range requested by the relevant TSO in accordance with the times t_1 and t_2 according to Table 3.

e) For HVDC systems linking various control areas or synchronous areas, in frequency sensitive mode operation the HVDC system shall be capable of adjusting full active power frequency response at any time and for a continuous time period

f) As long as a frequency deviation continues active power control shall not have any adverse impact on the active power frequency response.

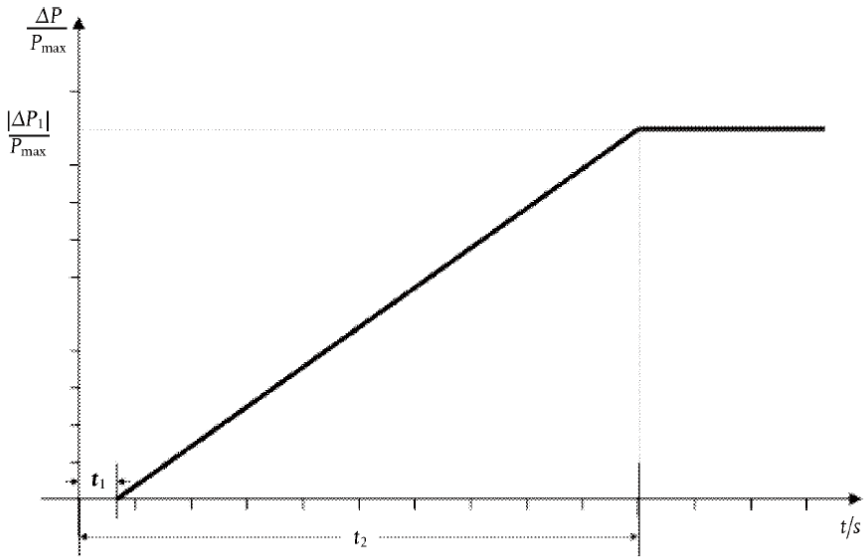

Figure 3 – Active power frequency response capability of an HVDC system [1]

In addition to the frequency requirements discussed in FSM, the following should apply regarding the Limited Frequency Sensitive Mode – Overfrequency (LFSM – O) [1]:

a) The HVDC system should be able to adjust the active power frequency response to the AC network or networks, according to

b) Figure 4 at a frequency threshold f_1 between and including 50.2 Hz and 50.5 Hz with a droop s_3 adjustable from 0.1% and upwards.

c) The HVDC system should be able to adjust the active power down to its minimum active power transmission capacity.

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d) The HVDC system shall be capable of adjusting the active power frequency response as fast as inherently technically feasible, with an initial delay and time for full activation determined by the relevant TSO.

e) The HVDC system shall be capable of stable operation during LFSM – O operation.

The frequency threshold and droop settings shall be determined by the relevant TSO.

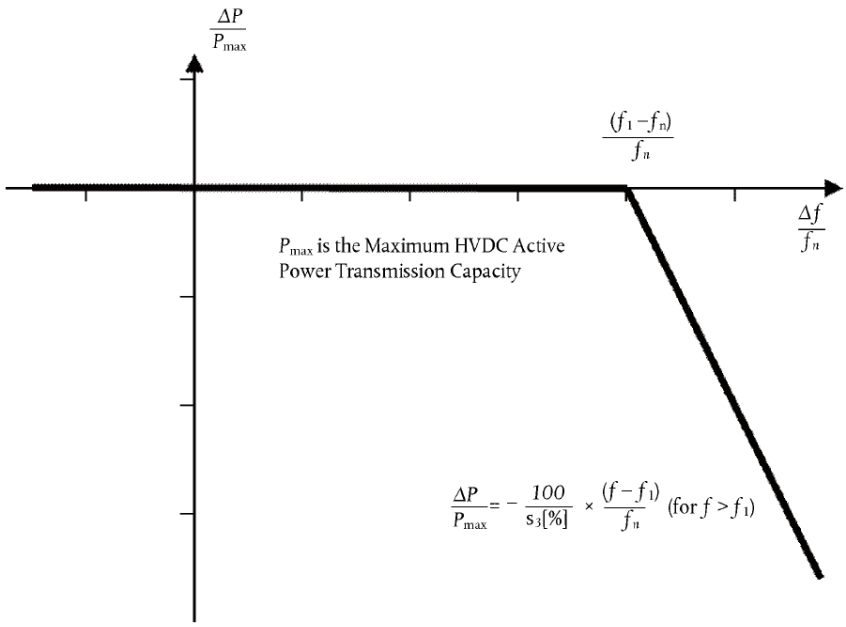

Figure 4 – Active power frequency response capability of an HVDC system in LFSM – O [1]

The equation linked with the LFSM – O is:

$$\frac{\Delta P}{P_{max}} = -\frac{100}{s_3[\%]} * \frac{f - f_1}{f_n}, \qquad (for\ f > f_1)$$

In addition to the frequency ranges discussed in FSM, the following shall apply regarding the Limited Frequency Sensitive Mode – Underfrequency (LFSM – U) [1]:

a) The HVDC system should be able to adjust the active power frequency response to the AC network or networks, according to Figure 5 at a frequency threshold f_2 between and including 49.8 Hz and 49.5 Hz with a droop s_4 adjustable from 0.1% and upwards.

b) The HVDC system should be capable to adjust the active power up to its maximum active power transmission capacity.

c) The HVDC system shall be capable of adjusting the active power frequency response as fast as inherently technically feasible, with an initial delay and time for full activation determined by the relevant TSO.

d) The HVDC system shall be capable of stable operation during LFSM – U operation.

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The frequency threshold and droop settings shall be determined by the relevant TSO.

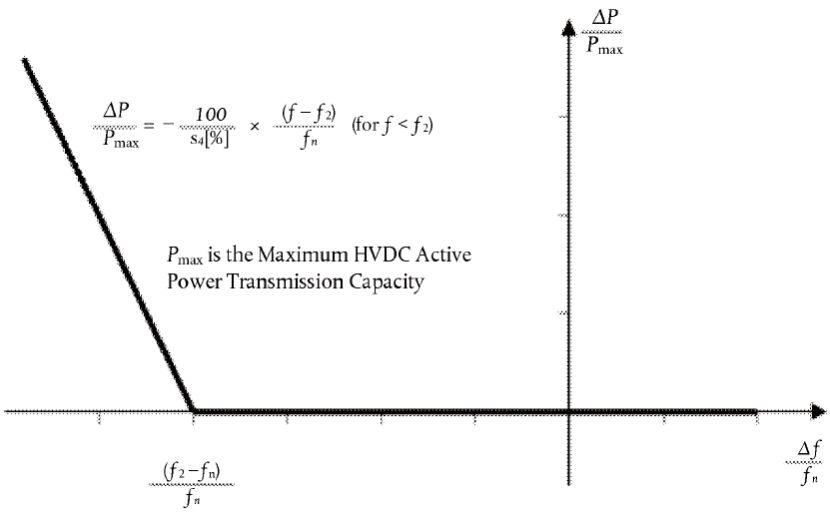

Figure 5 – Active power frequency response capability of an HVDC system in LFSM – U [1]

The equation linked with the LFSM – U is:

$$\frac{\Delta P}{P_{max}} = -\frac{100}{s_4[\%]} * \frac{f - f_2}{f_n}, \qquad (for\ f < f_2)$$

4.2.1.4 ACTIVE POWER CONTROLLABILITY, CONTROL RANGE AND RAMPING RATE

D1.1 The requirements associated to the HVDC system ability to receive instructions and active power set points and reacting accordingly are as follows:

a) Ability to control the active power up to the maximum power in both directions
b) Maximum allowed increase or decrease of power setpoint specified for adjusting the transmitted active power
c) Minimum active power transmission capacity for each direction, below which the active power transmission power capacity is not requested
d) Maximum time delay between receipt of the TSO request and start of the active power level adjustment;
e) Adjustment of the ramping rate, the ramping rate does not apply in case of fast power reversal or in case of disturbance to the AC system
f) Possibility to take remedial actions such as stopping the ramping and blocking the Frequency Sensitive Mode (FSM), with triggering criteria to be specified by the TSO
g) Fast response in case of disturbance on the AC network, with a maximum allowed delay from receiving the triggering signal by the relevant TSO

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h) For systems linking different AC control areas or synchronous areas, the HVDC system must be equipped with control functions enabling the relevant TSOs to modify the transmitted active power for the purpose of cross-border balancing

i) The control functions of an HVDC system must be capable of taking automatic remedial actions, including, but not limited to, stopping the ramping and blocking of the frequency control

D1.5

a) Not quantifiable.

b) Quantifiable but not available yet, quantification should be agreed between the relevant TSO's.

c) Quantifiable but not available yet, quantification should be agreed between the relevant TSO's.

d) The relevant TSO shall specify how an HVDC system shall be capable of modifying the transmitted active power infeed in case of disturbances into one or more AC networks to which it is connected. If the initial delay prior to the start of the change is greater than 100 ms from receiving the triggering signal sent by the relevant TSO, it shall be reasonably justified by the HVDC system owner to the relevant TSO [1].

e) An HVDC system shall be capable of adjusting the ramping rate of active power variations within its technical capabilities in accordance with instructions sent by the relevant TSOs. Grid code of different countries demand different levels of ramping rate [4]:

- Germany, with an upper ramp rate limit of 10% of grid connection capacity per minute
- Ireland, with a ramp rate of 1 – 30 MW/min
- Nordic grid code, with an upper ramp rate limit of 600MW/hour
- Denmark, with a ramp rate 10 – 100% of rated power per minute.

In case of fast power reversal the relevant TSO may specify that an HVDC system shall be capable of fast active power reversal. The power reversal shall be possible from the maximum active power transmission capacity in one direction to the maximum active power transmission capacity in the other directions as fast as technically possible and reasonably justified by the HVDC owner to the relevant TSO if the time is greater than 2 seconds [1].

f) Not quantifiable.

g) Quantifiable but a project specific requirement, example values are: Emergency Power control 100ms maximum delay than 5MW/s reduction.[3]

h) Not quantifiable.

i) For HVDC systems linking various control areas or synchronous areas, the HVDC system shall be equipped with control functions enabling the relevant TSOs to modify the transmitted active power for the purpose of cross – border balancing.

However in a meshed grid configuration coordinated control between the converters is needed. PPM controllers must be considered when connected via DRU in a meshed grid.

[3] Internal TenneT document, technical specification TS-HGÜ-150

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4.2.1.5 SYNTHETIC INERTIA

D1.1 The HVDC system must be capable of providing synthetic inertia support in response to frequency changes in one or more AC networks, activated in low and/or high frequency regimes by rapidly adjusting the active power injected to or withdrawn from the AC networks in order to limit the rate of change of frequency (ROCOF).
For an HVDC system connecting a power park module the adjustment of active power frequency response must be limited by the capability of the DC-connected power park modules.

D1.5 Quantifiable but not available yet since synthetic inertia is a very local and specific requirement.
An example of such a local and specific rerquirement follows from the Hydro-Quebec grid code: Wind power plants with a rated output greater than 10 MW have to emulate inertial response of a conventional synchronous generator whose inertia (H) equals to 3.5 s. The active power of wind power plants varies dynamically and rapidly by at least 5% of active power for about 10s, when a large, short-duration frequency deviation occurs on the power system [10].

4.2.1.6 MAXIMUM LOSS OF ACTIVE POWER

D1.1 The HVDC system must be designed in such a way that the maximum loss of active power infeed in a synchronous area be limited to a value specified by the relevant TSOs. The time dimension must be considered and differentiation between temporary and permanent losses of power must be made. This has implications on the design and the topology of the HVDC system as well as on the DC protection system.
Where an HVDC system connects two or more control areas, the relevant TSOs must consult each other in order to set a coordinated value of the maximum loss of active power injection, taking into account common mode failures.

D1.5 From D1.1 it follows that there is a need to differentiate between temporary and permanent losses of power. For the temporary power loss a time dimension of up to hundreds of ms was meant. Within that time dimension a differentiation is envisaged from a protection systems perspective which is further explained in the discussion of this document, Appendix C and will also be developed by WP4. The permanent power loss referred to any incident that takes longer than hunderds of ms (permanent from the perspective of protection systems). The 'reference incident' as described in article 153 Frequency containment reserves, as part of the provisional final version of the System Operation Guideline from ENTSO-E [19] serves as an appropriate quantification of the 'permanent' maximum power loss requirement.

Synchronous zone	Reference incident
Continental Europe	3000 MW [19]
Nordic	1350 MW [22]
Great Britain	1800 MW [18]
Ireland and Northern Ireland	Up to 500 MW [20]

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4.2.2 REQUIREMENTS FOR REACTIVE POWER CONTROL AND VOLTAGE SUPPORT

4.2.2.1 VOLTAGE RANGES

D1.1 The HVDC system should be able to remain connected to the system for given AC voltage range requirements at the converter stations deviating from the 1 pu reference value of voltage. They are dependent on the voltage level of the connection point as well as the synchronous area. An HVDC system must be capable of automatic disconnection at connection point voltages specified by the relevant TSO.

D1.5 The voltage ranges are listed per synchronous area in Table 4 (110kV – 300kV) and Table 5 (300kV – 400kV).

Synchronous area	Voltage range	Time period for operation
Continental Europe	0.85 pu – 1.118 pu	Unlimited
	1.118 pu – 1.15 pu	To be established by each relevant operator, in coordination with the relevant TSO but not less than 20 minutes
Nordic	0.90 pu – 1.05 pu	Unlimited
	1.05 pu – 1.10 pu	60 minutes
Great Britain	0.90 pu – 1.10 pu	Unlimited
Ireland and Northern Ireland	0.90 pu – 1.118 pu	Unlimited
Baltic	0.85 pu – 1.118 pu	Unlimited
	1.118 pu – 1.15 pu	20 minutes

Table 4 – Minimum time periods an HVDC system shall be capable of operating for voltage deviating from 1 pu value without disconnecting from the network. The table applies in case of pu voltages base values from 110kV to 300kV [1].

Synchronous area	Voltage range	Time period for operation
Continental Europe	0.85 pu – 1.05 pu	Unlimited
	1.05 pu – 1.0875 pu	To be established by each TSO, but not less than 60 minutes
	1.0875 pu – 1.10 pu	60 minutes
Nordic	0.90 pu – 1.05 pu	Unlimited
	1.05 pu – 1.10 pu	To be established by each TSO, but not more than 60 minutes

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Great Britain	0.90 pu – 1.05 pu	Unlimited
	1.05 pu – 1.10 pu	15 minutes
Ireland and Northern Ireland	0.90 pu – 1.05 pu	Unlimited
Baltic	0.88 pu – 1.097 pu	Unlimited
	1.097 pu – 1.15 pu	20 minutes

Table 5 – Minimum time periods an HVDC system shall be capable of operating for voltage deviating from 1 pu value without disconnecting from the network. The table applies in case of pu voltages base values from 300kV to 400kV [1].

Wider ranges of voltage levels or longer minimum times can be used for operation.

4.2.2.2 REACTIVE POWER CAPABILITY

D1.1 The relevant HVDC system, in coordination with the relevant TSOs, must specify the reactive power capability requirements at the connection points, in the context of varying AC voltage. The proposal for those requirements must include a U-Q/Pmax-profile, within the boundary of which the HVDC converter station must be capable of providing reactive power at its maximum HVDC active power transmission capacity.

D1.5 The profile U-Q/ Pmax – profile shall comply with the following [1]:

a) Shall not exceed the inner envelope as depicted in Figure 6 and does not need to be rectangular
b) The dimensions shall respect the values established for each synchronous area in Table 6
c) The position of the envelope shall lie within the limits of the fixed outer envelope as in Figure 6

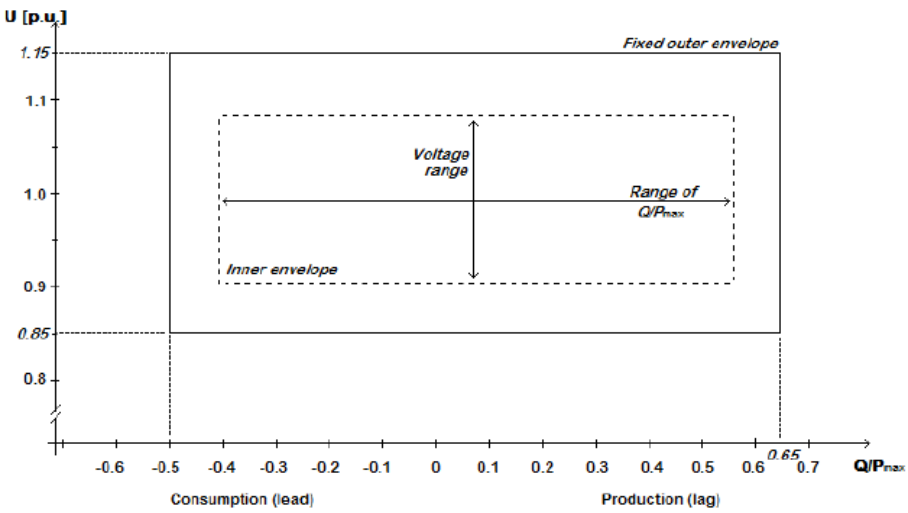

Figure 6 – The boundaries of the U-Q/ Pmax profile [1]

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The parameters for the inner envelope are listed in Table 6. The values listed in Table 6 represent the length of the arrows for the range of Q/Pmax and voltage range U inside the inner envelope and therefore represent ranges.

Synchronous area	Maximum range of Q/ Pmax	Maximum range of steady – state voltage level U in pu
Continental Europe	0.95	0.225
Nordic	0.95	0.15
Great Britain	0.95	0.225
Ireland and Northern Ireland	1.08	0.218
Baltic States	1.0	0.220

Table 6 – Parameters for the inner envelope [1]

An HVDC system shall be capable of moving to any operating point within its U-Q/ Pmax – profile in timescales specified by the relevant system operator. Note that it is therefore also optional to have no envelope or a limited one.

When operating at an active power output below the maximum HVDC active power transimission capacity, the HVDC converter station shall be capable of operating in every possible operating point, as specified by the relevant system operator in coordination with the relevant TSO.

4.2.2.3 REACTIVE POWER EXCHANGED WITH THE AC NETWORK

D1.1 The HVDC system must ensure that the reactive power of its HVDC converter station exchanged with the AC network at the connection point is limited to specified values.
The reactive power variation caused by the reactive power control mode operation of the HVDC converter station, must not result in a voltage step exceeding the allowed value at the AC connection point.

D1.5 Quantifiable but a project specific requirement.

4.2.2.4 REACTIVE POWER CONTROL MODE

D1.1 Three control modes must be possible:

- Voltage control mode
- Reactive power control mode
- Power factor control mode

In voltage control mode, a dead-band around the 1p.u. value may be enforced (adjustable by the TSO). Certain time requirements are enforced relating to rise time (time required to reach 90% of the reference value) and

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settling time (time required to settle within a certain tolerance of the AC voltage set point, defined by the relevant TSO).

Voltage control also has to include the possibility of providing reactive power output control through two set points, for voltage and reactive power respectively. Remote selection of the control mode and associated set points has to be foreseen. Maximum steps in the reference signals should be enforced to limit the disturbances to the grid.

D1.5 For the purposes of *voltage control mode*, each HVDC converter station must be capable of contributing to voltage control at the connection point utilising its capabilities. The relevant TSO shall specify especially the parameters in Table 7.

	Value range NC HVDC	**Example values**[4]
Setpoint voltage	As specified by relevant TSO	0.9 – 1.1 pu
Setpoint voltage step size	As specified by relevant TSO	Max 1 %
Deadband	0 - ± 5%	± 5%
Deadband step size	As specified by relevant TSO	Max 0.5 %
Slope	As specified by relevant TSO	2 – 7 % (6% default value)
Slope step size	As specified by relevant TSO	0.5 %
Rise time	0.1 s – 10 s	1 – 5 s
Settling time	1 s – 60 s	5 – 60 s (30 s default value)
Steady – state tolerance	-	5%

Table 7 – Parameters related to the voltage control mode [3]

Reactive power control mode aims at feeding constant reactive power at the connection point following a setpoint expressed in terms of reactive power. The relevant TSO shall specify especially the parameters in Table 8.

	Value range NC HVDC	**Example values**[4]
Setpoint	As specified by relevant TSO, using HVDC capabilities	0.41 pu ind. – 0.41 pu cap.
Setting steps	As specified by relevant TSO, using HVDC capabilities	Max. 5 MVAr or 5% (the lower value is valid)
Accuracy	As specified by relevant TSO, using HVDC capabilities	As specified by relevant TSO, using HVDC capabilities

Table 8 – Parameters related to the reactive power control mode [3]

[4] German working group for national implementantion of the HVDC National Code

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Power factor control mode aims at providing a constant power factor (at all active powers) at the connection point. The relevant TSO shall specify especially the parameters in Table 9

	Value range NC HVDC	**Example values**[4]
PF range	With respect to NC HVDC articles 20 and 21 [3]	0.925 ind. – 0.925 cap.
PF step size	As specified by relevant TSO	0.005
Dynamic		Setting time max 4 min
Tolerance	-	-

Table 9 – Parameters related to the power factor control mode [3]

4.2.2.5 PRIORITY TO ACTIVE POWER OR REACTIVE POWER CONTRIBUTIONS

D1.1 The relevant TSO will determine whether active or reactive power contribution has priority during low or high voltage operation and during faults for which fault-ride-through capability is required. If priority is given to active power contribution, its provision must be established within a time from the fault inception as specified by relevant TSO.

D1.5 Quantifiable but a project specific requirement, for example in Germany priority to reactive power will be proposed[4].

4.2.2.6 POWER QUALITY

D1.1 The relevant TSO must define maximum level of distortion allowed from the HVDC installation at the point of common coupling.

D1.5 Quantifiable but a project specific requirement.

4.2.3 REQUIREMENTS FOR FAULT RIDE THROUGH CAPABILITY

4.2.3.1 FAULT RIDE THROUGH CAPABILITY

D1.1 The relevant TSO specifies a voltage-against-time profile at the connection point, above which the HVDC converter station must be capable of staying connected and continue stable operation. The pre-fault and post-fault conditions to be used for the (Low Voltage Ride Through) LVRT capabilities are to be provided by the TSO. The TSO may specify voltages (Ublock) at the connection points under specific network conditions whereby the HVDC system is allowed to block. The relevant TSO must specify fault-ride-through capabilities in case of asymmetrical faults.

D1.5 Table 10 is a summary of Figure 7 which displays various LVRT curves for symmetrical balanced voltage dips for various grid codes.

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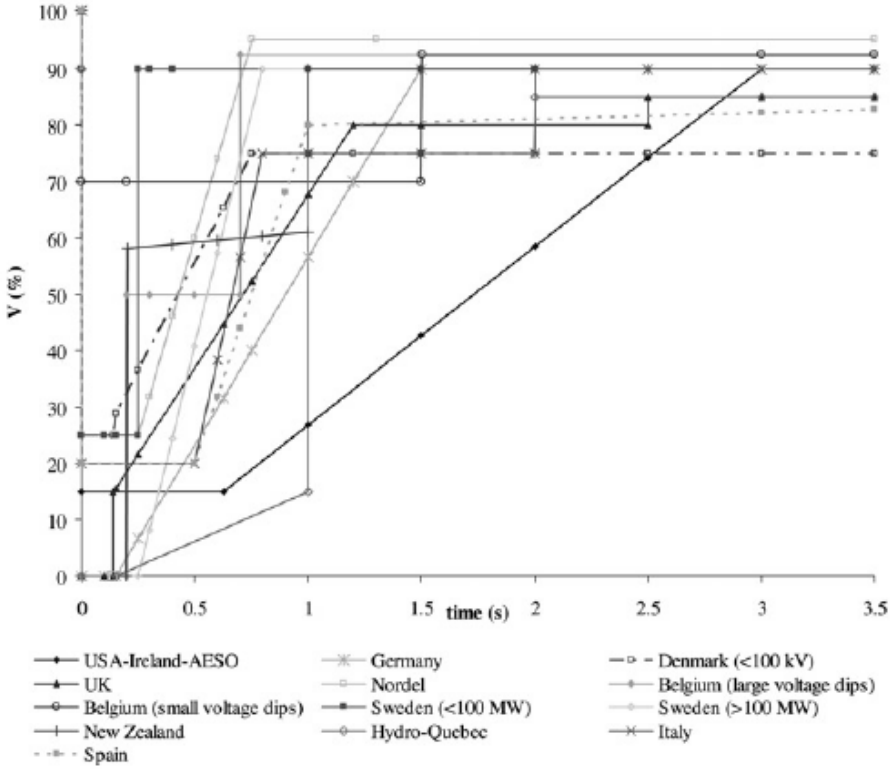

Figure 7 – LVRT requirements of various grid codes[4]

Grid code	Fault duration (ms)	Fault duration (cycles)	Min voltage level (% of V_{nom})	Voltage restoration (s)
Germany	150	7.5	0	1.5
UK	140	7	0	1.2
Ireland	625	31.25	15	3
Nordel	250	12.5	0	0.75
Denmark (<100 kV)	140	7	25	0.75
Denmark (>100 kV)	100	5	0	10
Belgium (large voltage dips)	200	10	0	0.7
Belgium (small voltage dips)	1500	75	70	1.5
Spain	500	25	20	1
Italy	500	25	20	0.8
Sweden (<100 MW)	250	12.5	25	0.25
Sweden (>100 MW)	250	12.5	0	0.8

Table 10 – Characteristics of fault ride through curves of various grid codes [4]

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4.2.3.2 SHORT – CIRCUIT CONTRIBUTION DURING FAULTS

D1.1 The HVDC system is required to have the capability of providing fast fault current at a connection point in case of symmetrical three-phase fault, if and as specified by the TSO. The following characteristics are then specified:

- Conditions for activating the fault current contribution;
- Characteristics of the fast fault current;
- Timing and accuracy of the fast fault current, which may include several stages.

A requirement for asymmetrical current injection in the case of asymmetrical faults is specified by the TSO (1-phase or 2-phase).

D1.5 Not quantifiable. In addition to D1.1 the reactive current injection shall not lead to over-voltages in the healthy phases and support the voltage in the fault-affected phases only [9]. The relevant TSO shall also specify whether and how much the negative-sequence fault current contribution is requested during unbalanced short – circuit faults. From a converter perspective, the voltage stays synchronised as long as there is some residual AC voltage left at the PCC. In the very rare case that the residual voltage is not sufficient, the converter may lose synchronism, if the AC system voltage phase angle changes significantly. This would require the converter to re-synchronise upon AC voltage recovery as soon as possible (typically one network cycle).

4.2.3.3 POST – FAULT ACTIVE POWER RECOVERY

D1.1 The relevant TSO must specify the magnitude and time profile of active power recovery that the HVDC system must be capable of providing to the AC system.

D1.5 As an example, in the British grid code it is stated that after the restoration of the voltage, the active power must be restored to at least 90% of the level available before the dip within 1 second (which is also possible in 0.5 second) [4]. In the German grid code, it requires restoration with a rate at least equal to 20% of the nominal output power per second reaching 100% in 5 seconds after voltage recovery [4][8].

4.2.3.4 FAST RECOVERY FROM DC FAULTS

D1.1 HVDC systems, including DC overhead lines and cables, must be capable of clearing and isolating the DC fault and fast recovery from transient faults within the HVDC system. Details of this capability must be subject to coordination and agreements on protection schemes and settings.

D1.5 Not quantifiable. Coordination and agreements on protection schemes and settings are discussed in chapter 7.

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4.2.4 REQUIREMENTS FOR CONTROL

4.2.4.1 ENERGIZATION AND SYNCHRONIZATION

D1.1 Limits on acceptable transients on the AC system during these operations must be enforced by the relevant TSO.

D1.5 The HVDC converter station during the energization and synchronization of the converter to the AC network or during the connection of the station with an HVDC system shall have the capability of limiting any voltage ranges to a steady – state level. The specified level should not exceed 5% of the pre – synchronization voltage.

4.2.4.2 INTERACTION BETWEEN HVDC SYSTEMS AND OTHER AC CONNECTED PLANTS AND EQUIPMENT

D1.1 The HVDC converter controllers and filters must be designed to ensure that no adverse interaction occurs between stations and nearby electrical equipment.
The relevant TSO may specify transient levels of performance associated with events for the individual HVDC system or collectively across commonly impacted HVDC systems. This specification may be provided to protect the integrity of both TSO equipment and equipment of grid users in order to comply with the relevant standards and codes.

D1.5 Not quantifiable.

4.2.4.3 POWER OSCILLATION DAMPING CAPABILITY

D1.1 The HVDC system must be capable of contributing to the damping of power oscillations in the connected AC systems. The connecting TSO must provide the frequency range for which damping is to be provided and final settings for the damping controller are agreed following discussions with the connecting TSO. The introduction of the HVDC system should not lead to un-damped oscillations and should not degrade the damping level in the AC system.

D1.5 The control system of the HVDC system shall not reduce the dampings. The relevant TSO shall specify a frequency range of oscillations that the control scheme shall positively damp and the network conditions when this occurs, at least accounting for any dynamic stability assessment studies undertaken by TSOs to identify the stability limits and potential stability problems in their transmission systems.

Results obtained from MTDC systems [6] have shown that these systems do not participate in the electromechanical modes of oscillation when properly designed. Aproper tuning the POD (Power Oscillation Damping) control of HVDC will not cause any adverse effects to the system. PSS based controllers [6] installed in the AC side of the VSC – HVDC converter can contribute for increasing the system damping levels. Different grid codes require different minimum and maximum damping levels e.g. in the UK grid code, the tuning of the PSS shall be judged to be adequate if the corresponding active power response shows improved damping with the PSS in combination with the AVR compared with the AVR alone over the frequency range 0.3 Hz – 2 Hz.

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4.2.4.4 SUB SYNCHRONOUS TORSIONAL INTERACTION DAMPING CAPABILITY

D1.1 The HVDC system must be capable of contributing to electrical damping of sub-synchronous torsional interaction (SSTI).

D1.5 Quantifiable but not available yet, and will not be used as an input for the different Work Packages.

4.2.4.5 NETWORK CHARACTERISTICS

D1.1 The relevant TSO must make available the pre-fault and post-fault conditions for calculations of the minimum and maximum short circuit power at the connection points. The HVDC system must be capable of operating within the range of short circuit power and network characteristics specified by the TSO.

D1.5 The method for the calculation of the pre – fault and post – fault conditions shall be made public for the calculation of at least the minimum and maximum short – circuit power at the connection points. According to [11], an AC system can be defined as a strong system, if the SCR of the AC system is greater than 3.0, a weak system, if the SCR of the AC system is between 2.0 and 3.0 and a very weak system, if the SCR of the AC system is less than 2.0. Work is ongoing (e.g Cigre B4 – 64) to redefine these limits for VSC HVDC connected systems.

4.2.5 REQUIREMENTS FOR PROTECTION DEVICES AND SETTINGS

4.2.5.1 PRIORITY RANKING OF PROTECTION AND CONTROL

D1.1 The HVDC system protections and control devices must be organised in compliance with the following priority ranking, in decreasing order of importance:

- AC system and HVDC system protection
- Active power control for support of the AC system in emergency conditions
- Synthetic inertia, if applicable
- Automatic remedial actions
- LFSM
- FSM and frequency control
- Power gradient constraint

D1.5 Not quantifiable.

4.2.5.2 CHANGES TO PROTECTION AND CONTROL SCHEMES AND SETTINGS

D1.1 The control modes and associated set points of the HVDC system must be capable of being changed remotely, as specified by the relevant system operator, in coordination with the relevant TSO.

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D1.5 Not quantifiable.

4.2.6 REQUIREMENTS FOR POWER SYSTEM RESTORATION

4.2.6.1 BLACK START

D1.1 An HVDC system may provide black start services to a TSO. An HVDC system with black start capability must be able, in case one converter station is energised, to energise the busbar of the AC-substation to which another converter station is connected, within a time frame after shut down determined by the relevant TSOs. The HVDC system must be able to synchronise within specified frequency limits and voltage limits. The black start availability, capability and the associated operational procedure must be specified by the relevant TSO.

D1.5 Not quantifiable.

4.2.7 INFORMATION EXCHANGE AND COORDINATION

4.2.7.1 OPERATIONAL REQUIREMENTS OF HVDC SYSTEMS

D1.1 With regard to instrumentation for the operation, each HVDC converter unit of an HVDC system must be equipped with an automatic controller capable of receiving set points and commands from the relevant system operator and from the relevant TSO. This automatic controller must be capable of operating the HVDC converter units of the HVDC system in a coordinated way. The relevant system operator must specify the automatic controller hierarchy per HVDC converter unit. The automatic controller of the HVDC system must be capable of sending the following signals to the relevant system operator:

- operational signals, providing at least the following
    - start-up signals
    - AC and DC voltage & current measurements
    - active and reactive power measurements on the AC side
    - DC power measurements
    - HVDC converter unit level operation in a multi-pole type HVDC converter
    - elements and topology status
    - FSM, LFSM-O and LFSM-U active power ranges
- alarm signals, providing at least the following
    - emergency blocking
    - ramp blocking
    - fast active power reversal

The automatic controllers must be capable of receiving the following types of signals from the relevant system operator

- operational signals, receiving at least the following:

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    - start-up command
    - active power set points
    - frequency sensitive mode settings
    - reactive power, voltage or similar set points
    - reactive power control modes
    - power oscillation damping control
    - synthetic inertia
- alarm signals, receiving at least the following:
    - emergency blocking command
    - ramp blocking command
    - active power flow direction
    - fast active power reversal command

D1.5 Not quantifiable.

4.3 DISCUSSION

In the process of developing D1.5 some concerns and discussion items were addressed. Therefore in this section a discussion is drafted about limitations imposed by the grid codes, control capabilities, power flows and the maximum power loss.

There are many requirements introduced by the HVDC grid code as a range where the TSO is the entity to specify the exact values on a case by case basis. This implies a certain risk to developers at the beginning of the project as requirements can be unclear. Requirements with ranges as quantifications give a certain degree of freedom in the design of systems and acceptance by TSOs.

For example, the requirements that TSOs can (but not necessarily have to) impose based on the HVDC grid code do not favour LCC technology. Actions could be required (such as building a STATCOM) to fulfil the requirements that could make LCC not economically attractive. For example:

- The reactive power control mode requirement, as stated in 4.2.2.4, discriminates LCC type converters since these three control modes (voltage, reactive power, power factor) can only be achieved with a VSC type converter.
- The short – circuit contribution during faults requirement, as stated in 4.2.3.2, requires that the HVDC system should be capable of providing Reactive Short Circuit Current contribution during periods of faults. It is important to note that it is the 'system' that needs to be able to deliver the short – circuit contribution and not necessarily all converters. Further, based on the available information from the vendors of HVDC technology, this requirement will have a sizeable impact on CAPEX of such installations. LCC converters will require installation of Statcoms or rotating condensers to comply with this requirement.

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Concerns for a meshed offshore HVDC grid were raised about the control capabilities. The following issues/questions have emerged:

- DC voltage will likely be used as a tool for power flow control over DC lines and the normal DC voltage range may need to be extended. This may have an impact on harmonic generation.
- DC line power flow controllers may be required as the complexity of the grid grows. There are no requirements available yet for such equipment.
- The DC grid may be established by connection of various point-to-point connections coming together which might need „DC transformers“ for which there is no requirement available right now.
- For active power control no regulations are available at the moment but this could become relevant in the future.
- For power oscilation damping, it should be specified when and whether the POD controller should use the reactive power/voltage control or the active power control. Using the active power control in the first AC grid will affect all other grids and the effect may increase if such controls are simultaneously used in several AC systems.

Concerning the power flows, the flows at every DC terminal, which is part of a meshed grid connected to the AC system, can be bidirectional. The following issues/questions are emerging:

- A future Meshed DC grid consisting of many VSCs will technically be able to provide very fast changes in direction of flows. If operators would like to make use of these capabilities, new control mechanisms have to be developed.
- Coordination between DC converters in the same synchronous area can allow the TSO(s) to have more control and realize additional benefits such as optimal power flows. Such coordination requires the detailed analysis and agreements between different operators.
- Speed of change of active power would be a challenge if there is a DRU included in the DC network.

HVDC protection equipment could allow for fault clearing in time scales of tens to hundreds of miliseconds, which is less than fault clearing times of an AC system. This started a discussion about the maximum power loss that an AC system can lose in these timescales, which might be higher than the existing permanent maximum power loss definied in the grid codes. By allowing higher temporary losses of power, different HVDC protection system philosophies become available. This discussion is further addressed in WP4 (D4.1) in which the concept of higher temporary power lossess is explained. A summary of this concept and related protection philosophies can be found in Appendix C.

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5 MESHED OFFSHORE GRID – OFFSHORE GENERATION

This chapter has quantified the qualitatitve requirements that were agreed in the Deliverable 1.1. The topology considered in this chapter is given in Figure 8 (OWF transformer not strictly needed), where the offshore HVDC terminal could be either VSC (A in the figure) or DRU (B in the figure):

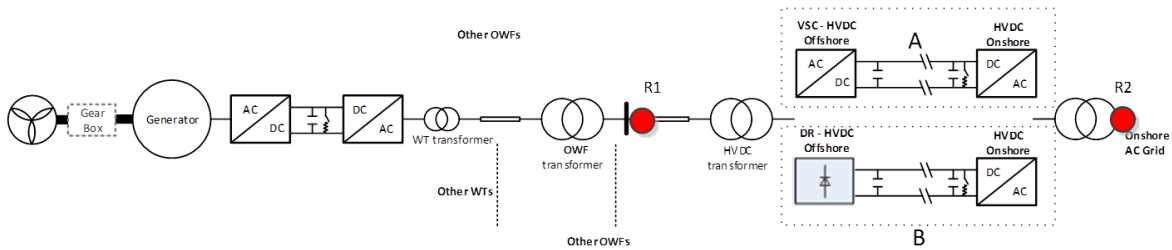

Figure 8 – Considered topologies in Chapter 5

Requirements for the OWFs connected at the R1 interface point are given in section 5.1 below mainly based on the Network code for HVDC connections (NC HVDC), which cover “DC – connected power park modules’”, but also the network code for Requirements for the Generators (NC RfG). Requirements for the offshore HVDC terminals at the R1 interface point are given in section 5.2 below, utilizing the requirements specified in ENTSO-E Network Code on HVDC Connections (NC HVDC), which covers Remote-End HVDC Converter Stations. Since the DRU and OWF can be considered as a common unit, the main electrical requirements shall also be imposed to such common unit. Therefore, the chapter will make distinct requirements for the DRU if this is applicable. This will be presented in this chapter as follows:

D1.5 If there is no disticintion between the quantitatvie requirements for VSC and DRU the quantification will be written as a general D1.5 quantification.

VSC If there is a distinction between the quantitative requirements for VSC and DRU will be written as a VSC quantification.

DRU If there is a distinction between the quantitative requirements for VSC and DRU will be written as a DRU quantification.

Taking the NC HVDC and the NC RfG grid codes as a starting point is problematic for some components, as these codes do not take into account a Meshed Configuration (they assumes point-to-point connections). The chapter therefore ends with a discussion about additions that should be made for the purpose of a Meshed Offshore Grid, with quantifications if possible. Of course, any suggested changes to the NC HVDC grid code will have to follow the regular code change procedures. In the discussion chapter, there is also room for discussion about the direction in which values could develop over time. On a 10-30 year timescale, certain parameters will

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not remain constant. The grid codes frequently refer to 'the relevant TSO'. This is left intact in this chapter, even though the nature of the entity responsible for these tasks for the MOG needs to be defined in Work Package 7.

Additional explanation for the DRU configurations taken into account for this section

Due to the technical characteristics of a DRU system, the Offshore Transmission System has several Configurations: The following specifies the different configurations, which are defining two main operational states (Table 11):

a. Initialization (Aux) state – establishing offshore MV busbar stable voltage (SAC)
b. Transmission state – produced active power is transmitted via HVDC line to the onshore connection point (DR, DRSAC).

Indetifier	Description
ISL	Island operation: *The OWF is neither connected to a DR nor to an alternate AC system (be it synchronised or unsynchronised) i.e. the OVF is completely islanded and has to maintain its own power/frequency balance.* Only temporary islanding considered here!
UAC	Unsynchronised AC: The OWF is connected to an alternate AC system such as a local generator or VSC converter which is not synchronized with the main AC system nor has any other strong frequency control characteristics. Not considered here!
SAC	Synchronised AC: *The OWF is connected to the main AC system or another AC system with strong frequency control characteristics.*
DR	Diode Rectifier: *The OWF is connected to a diode rectifier only.*
DRUAC	Diode Rectifier and unsynchronised AC: *The OWF is connected to a diode rectifier and an alternate AC system such as a local generator or VSC converter which is not synchronized with the main AC system nor has any other strong frequency control characteristics.* Not considered here!
DRSAC	Diode Rectifier and synchronised AC: *The OWF is connected to a diode rectifier and another AC system with strong frequency control characteristics.*

Table 11 – DRU configurations which define the main operational states

The system overview in Figure 9 shows the scope of the application of the OWF requirements for DRU connected OWFs. Note that this is just an exemplary schematic system, for example, the umbilical cable is optional, but might not be necessary if black start capability and auto-synchronous operation of OWFs are considered.

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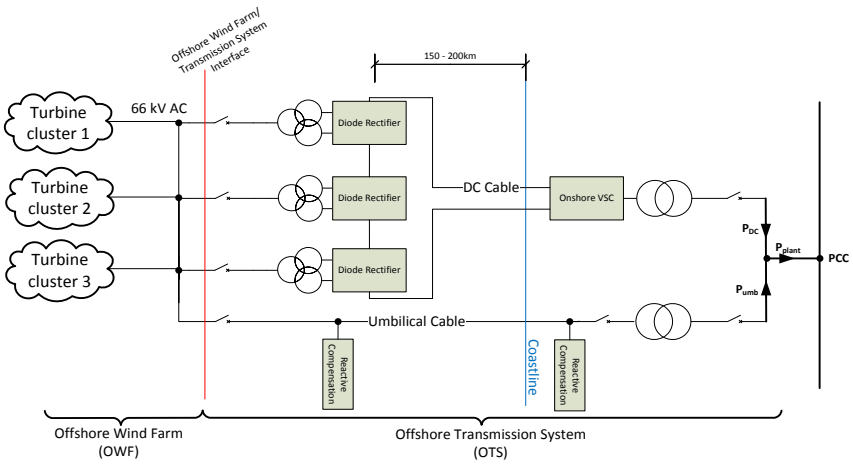

Figure 9 – Exemplary system overview of an DRU connected system.

5.1 REQUIREMENTS FOR OFFSHORE WIND FARMS (OWFS)

5.1.1 ACTIVE POWER CONTROL AND FREQUENCY STABILITY

5.1.1.1 MAXIMUM POWER POINT TRACKING

D1.1 The Wind Turbine Generators (WTGs) that OWFs consist of must be capable of performing Maximum Power Point Tracking (MPPT).

D1.5 Not quantifiable.

5.1.1.2 OPERATIONAL FREQUENCY RANGE

D1.1 OWF should be capable of remaining connected to the network and operate within a specified frequency ranges.

D1.5

VSC Minimum time periods, for which the PPM shall be capable of operating for different frequencies, are listed in Table 12.

Frequency Range	Time period for operation
47.0 Hz – 47.5 Hz	20 seconds
47.5 Hz – 49.0 Hz	90 minutes
49.0 Hz – 51.0 Hz	Unlimited
51.0 Hz – 51.5 Hz	90 minutes
51.5 Hz – 52.0 Hz	15 minutes

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Table 12 – Minimum time periods for the 50 Hz nominal system for which a PPM shall be capable of operating for different frequencies without disconnecting from the network [1]

DRU Frequency ranges specified here are concerned with the fundamental frequency of the OWF AC voltage measured at the entry point of the transmission system. The frequency can be measured according to IEC-61400-21 (Measured as a moving average over 200ms). The emergency boundaries are defined for all transmission system configurations in Table 13.

Frequency Range	Time period for operation
47.0 – 52.0Hz	<10s
47.5 – 51.5Hz	<600s
48.0 – 51.5Hz	<1200s
48.5 – 50.5Hz	<1800s
49.0 – 50.5Hz	<3000s

Table 13 – Boundary between abnormal and emergency frequency ranges.

Due to the different frequency range requirements, which apply depending on the transmission system configuration, the definition of the normal- and abnormal frequency ranges are separated into two sections:

1) Standard (extended) frequency range: The following frequency ranges apply in operational modes SAC, DRSAC, UAC and DRUAC. This is a DRU solution specific requirement, not based on any grid code specification. The narrow frequency ranges are needed to assure optimal filter design and operation. The frequency ranges are listed in Table 14.

Frequency Range	Time period for operation
47.0 – 52.0Hz	<10s
47.5 – 51.5Hz	<600s
48.0 – 51.5Hz	<1200s
48.5 – 50.5Hz	<1800s
49.0 – 50.5Hz	<3000s

Table 14 – Boundary between normal and abnormal frequency range for the standard frequency range In operational modes SAC, DRSAC, UAC and DRUAC

Note: Now, these requirements are the same as for “Diode Rectifier Conduction”, but as the OWF can be directly (AC) connected to the onshore power system, specific onshore requirements might need to be considered here.

2) Optimized (narrow) frequency range: The following frequency ranges apply in operational mode DR. This is a DRU solution specific requirement, not based on any grid code specification. The narrow frequency ranges are needed to assure optimal filter design and operation. The frequency ranges are listed in Table 15.

Frequency Range	Time period for operation

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49.000 – 51.000Hz	<500ms
49.500 – 50.500Hz	<10s
49.875 – 50.125Hz	Steady state

Table 15 – Boundary between normal and abnormal frequency range in operational mode DR

Normal range might change depending on actual grid code requirements where the wind power plant is connected. The frequency is provided as a setpoint to the OWF.

5.1.1.3 OPERATIONAL RATE OF CHANGE OF FREQUENCY

D1.1 With regard to the rate of change of frequency withstand capability, OWFs should be capable of staying connected to the network and operate at rates-of-change-of-frequency up to a specified value. OWFs should be capable of automatic disconnection at specified rates-of-change-of-frequencies.

D1.5 A DC – connected power park module shall be capable of staying connected to the remote – end HVDC converter station network and operable if the system frequency changes at a rate up to ± 2 Hz/s (measured at any point in time as an average of the rate of change of frequency for the previous 1 second) [1]. ROCOF ranges specified in Figure 10 are concerned with ROCOF of the fundamental frequency of the OWF AC voltage measured at interface between the OWF and OTS. ROCOF can be measured as a moving average over the last 10 periods. The frequency is provided as a setpoint to the OWF in case of Transmission state.

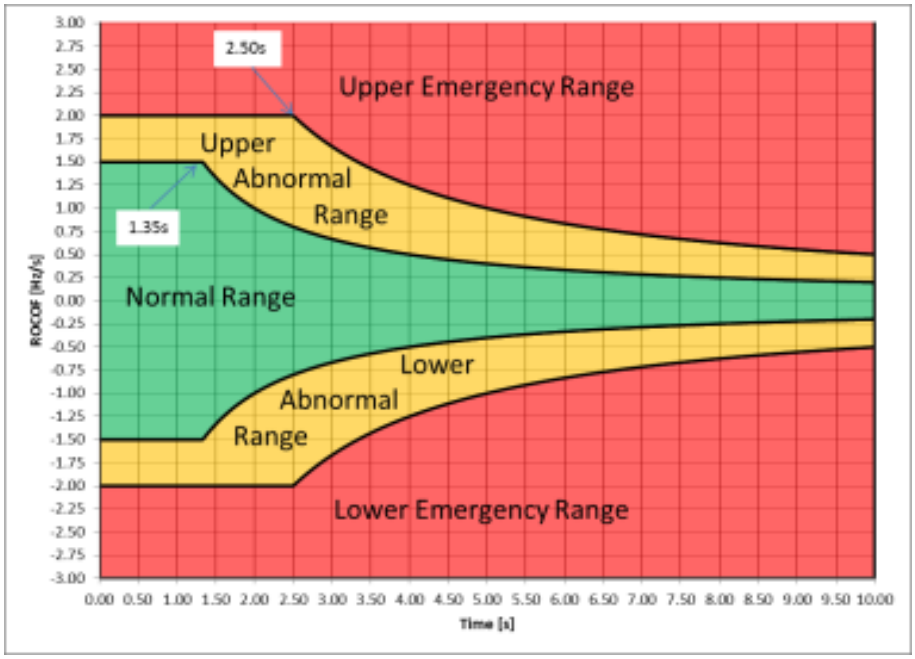

Figure 10 – ROCOF Ranges

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5.1.1.4 ACTIVE POWER INDEPENDENCY OF FREQUENCY

D1.1 OWF module should be capable of maintaining constant output at its target active power value regardless of changes in frequency inside the range specified.

D1.5 Regarding the limited frequency sensitive mode – Overfrequency (LFSM – O) for OWFs the following shall be applied:

- The power-generating module shall be capable of activating the active power frequency response according to Figure 11

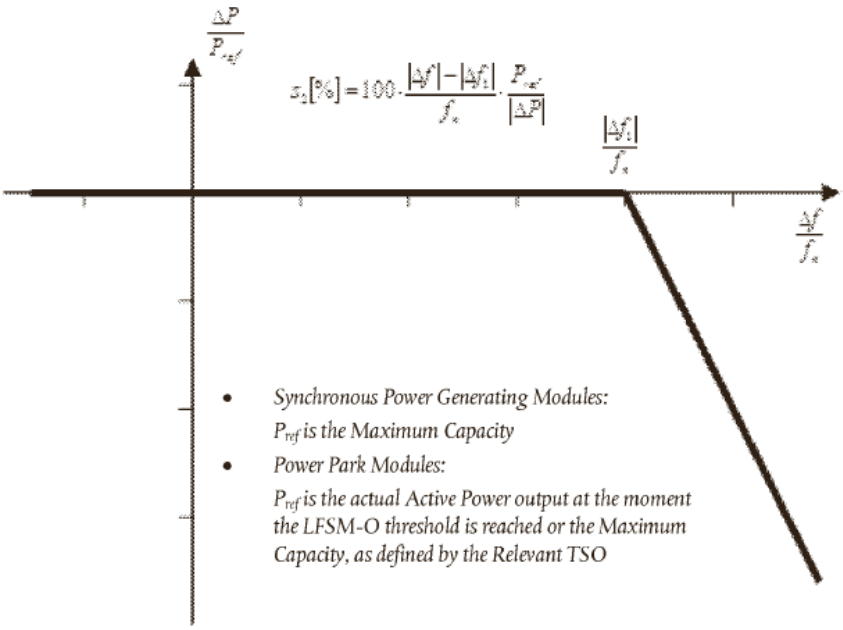

Figure 11 – Active power frequency response for power – generating modules capability in LFSM – O [2]

- Frequency threshold shall be between 50.2 Hz and 50.5 Hz inclusive [2].
- Droop settings shall be between 2% and 12% [2].
- The power-generating module shall be capable of activating a power frequency response with an initial delay that is as short as possible. If the delay exceeds two seconds, the power – generating facility owner shall justify the delay [2].

In addition to the requirements for the LFSM – O, the following shall be applied for Type C and Type D (Appendix A) power – generating modules regarding the limited frequency sensitive mode (LFMS – Underfrequency):

- It shall be capable of activating the active power frequency response at a frequency threshold and with a droop specified by the relevant TSO.

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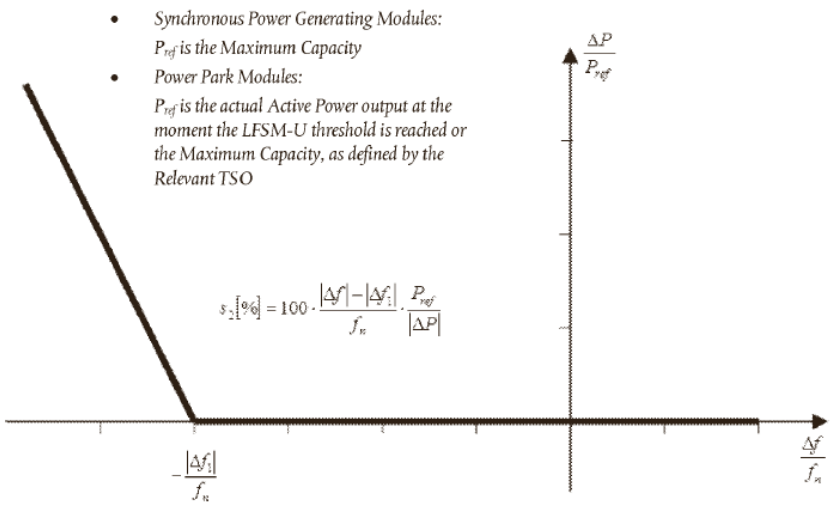

Figure 12 – Active power frequency response capability of power – generating module in LFSM – U [2]

- The frequency threshold specified by the TSO shall be between 49.8 Hz and 49.5 Hz inclusive [2].
- The droop settings specified by the TSO shall be between 2% - 12% [2].

In addition to the requirements for the LFSM – U, the following shall be applied when frequency sensitive mode (FSM) is operating:

- In case of overfrequency, the active power frequency response is limited by the minimum regulating level.
- In case of underfrequency, the active power frequency response is limited by maximum capacity.

Frequency sensitive mode FSM is defined as the operating mode of a power – generating module or HVDC system in which the active power output changes in response to a change in system frequency, in such a way that it assists with the recovery to target frequency;

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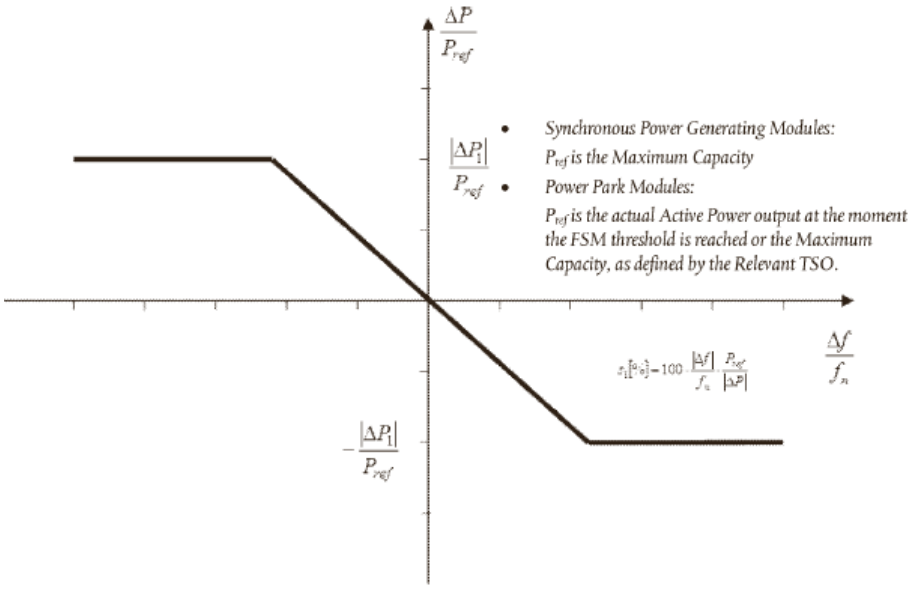

Figure 13 – Active power frequency response capability of power – generating modules in FSM [2]

In Table 16 the parameters for Figure 14 are displayed.

Parameters	Notation	Ranges
Active power range related to maximum capacity $\frac{\lvert DP_1 \rvert}{P_{max}}$		1.5 – 10%
Frequency response insensitivity	$\lvert \Delta f_i \rvert$	10 – 30 mHz
	$\frac{\lvert \Delta f_i \rvert}{f_n}$	0.02 – 0.06%
Frequency response deadband		0 – 500 mHz
Droop s_1		2 – 12%

Table 16 – Parameters associated with the active power frequency response in FSM [2]

- In the case of a frequency step change, the power – generating module shall be capable of activating full active power frequency response. A list of parameters is listed in Table 17.

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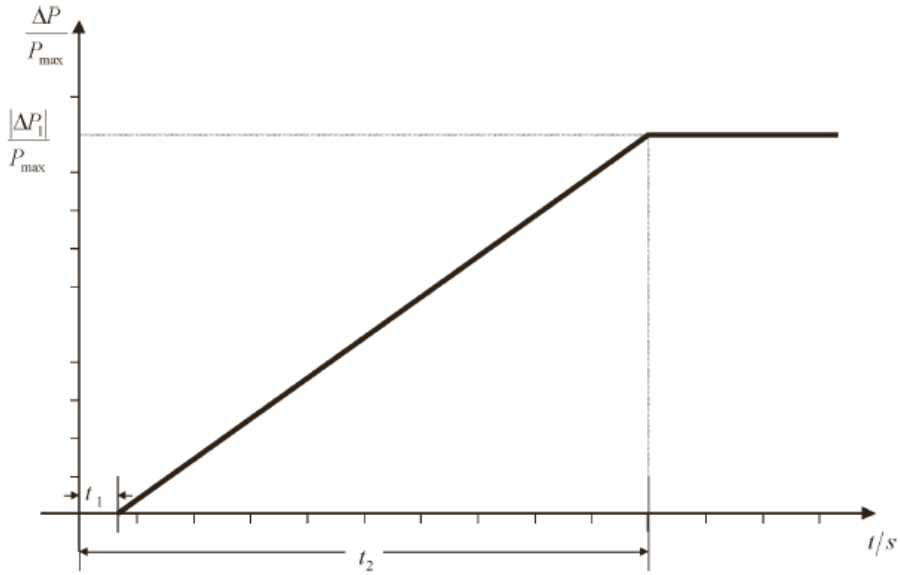

Figure 14 – Active power frequency response capability

Parameters	Ranges or values
Active power range related to maximum capacity (frequency response range) $\frac{\lvert\Delta P_1\rvert}{P_{max}}$	1.5 – 10%
For power – generating modules with inertia, the maximum admissible delay t_1 unless justified otherwise	2 seconds
For power – generating modules without inertia, the maximum admissible initial delay t_1 unless justified otherwise	As specified by the relevant TSO. For example: T1 is specified to be max 0.5 s for PPM with and without inertia.[5]
Maximum admissible choice of full activation time t_2, unless longer activation times are allowed by the relevant TSO for reasons of system stability	30 seconds

Table 17 – Parameters for full activation of active power frequency response resulting from frequency step change [2]

5.1.1.5 ACTIVE POWER CONTROL

D1.1 OWFs should be capable of adjusting an active power setpoint in line with instructions given to the OWF operator by the relevant system operator (constrained by available power). Tolerance (depending on the availability of wind resource) applying to the new setpoint and the time period within which it must be reached will be specified. Minimum and maximum limits on rates of change of active power output (ramping limits) in both increases and decreases of active power output for OWF will be specified.

[5] German working group for national implementantion of the HVDC National Code

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D1.5 To support normal operation, the OWF shall be capable of ramping active power from one set point to another within 10 seconds[6].

5.1.1.6 FREQUENCY RESPONSE PROCESSING[7]

D1.1 OWF shall be capable of receiving an onshore frequency signal (measured at the onshore synchronous area connection point and sent by the onshore converter or master controller).
OWFs connected via HVDC systems which connect with more than one control area should be capable of delivering coordinated frequency control which will be separately specified.
OWFs that are directly connected to onshore synchronous area (for instance via AC offshore interconnection to an AC-connected OWF) will respond without need for communication.

D1.5 Not quantifiable.

5.1.1.7 FREQUENCY RESPONSE ACTIVATION

D1.1 OWF should be capable of activating a power frequency response with an initial delay that is as short as possible. The frequency response will take into account: ambient conditions (mainly wind speed) at the time of response triggering and the operating conditions of the OWF, especially near the maximum capacity at low frequencies. OWF should be capable of providing active power frequency response for a specified duration.

D1.5 OWF shall be capable of activating a power frequency response with an initial delay that is shorter than 0.5 s from receiving the signal (over- or under-frequency) and time for full activation shall be shorter than 30 seconds according to [1] article 38 and [2] article 15 (2) (d) (iii).
OWF frequency response will take into account: ambient conditions (mainly wind speed) at the time of response triggering and the operating conditions of the OWF, especially near the maximum capacity at low frequencies; such that OWF cannot produce more than available (available wind and rotational kinetic energy).
OWF should be capable of providing active power frequency response for minimum 15 minutes according to [1] article 38 and [2] article 15 (2) (d) (v), while taking the primary energy source of the power-generating module into account.

5.1.1.8 FREQUENCY RESPONSE PARAMETERIZATION

D1.1 OWFs should be able to provide active power frequency response based on a set of specified parameters which allow for the calculation of the active power as a function of the frequency. The combination of choice of the parameters specified should take potential technology-dependent limitations into account.

[6] This number is based on engineering judgement.
[7] Changed requirement as set by D1.1

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D1.5 OWF shall be able to respond based on the set of specified parameters, which allow for the calculation of the active power as a function of the frequency, as shown in Figure 15. The combination of choice of the parameters specified should take possible technology-dependent limitations into account.

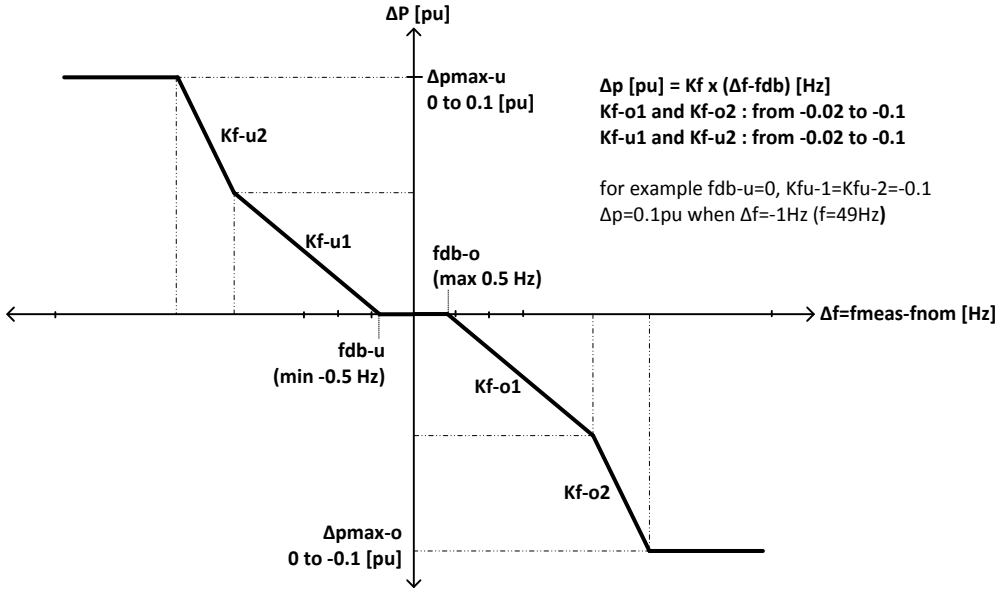

Figure 15 – Frequency response capability of OWF to onshore frequency changes according to [1] article 38 and [2] article 15 (2) (d) (i)

5.1.1.9 SYNTHETIC INERTIA

D1.1 OWFs may be required to provide synthetic inertia. The operating principle of control systems installed to provide synthetic inertia and the associated performance parameters will be specified by the relevant system operator.

D1.5 Quantifiable but not available yet since synthetic inertia is a very local and specific requirement.
As an example, OWF shall perform synthetic inertial response of a conventional synchronous generator whose inertia (H) equals to 3.5 s [10]. OWF shall be able to provide at least 5% of the actual active power for about 10s, when a large, short-duration frequency deviation occurs on the power system. The synthetic inertia requires a very fast response, which might not be feasible considering the communication time delay to the OWF

5.1.1.10 DC VOLTAGE RESPONSE

D1.1 OWFs may be required to contribute to DC voltage response to support the HVDC grid. This is to be done in coordination with requirements set out in Section 5.2 for HVDC Terminals and requirements must take into account OWFs capabilities.

D1.5 Not quantifiable.

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5.1.2 ROBUSTNESS AND CONTROL DURING SHORT – CIRCUIT FAULTS

5.1.2.1 OFFSHORE AC FAULT RIDE THROUGH

D1.1 OWF should be capable of staying connected to the network and continuing to operate after the network has been disturbed by securely cleared (symmetrical and asymmetrical) faults, which results in a voltage within a specified voltage-against-time-profile at the connection point.

Under specified conditions, OWF should be capable of reconnecting to the network after an incidental disconnection caused by a network disturbance.

In case of disconnection of the OWF from the offshore network, the OWF should be capable of quick re-synchronisation in line with the agreed protection strategy.

D1.5 With regard to fault ride through capability of power generating modules, each TSO shall specify a voltage against time profile in line with Figure 16 at the connection point for fault conditions.

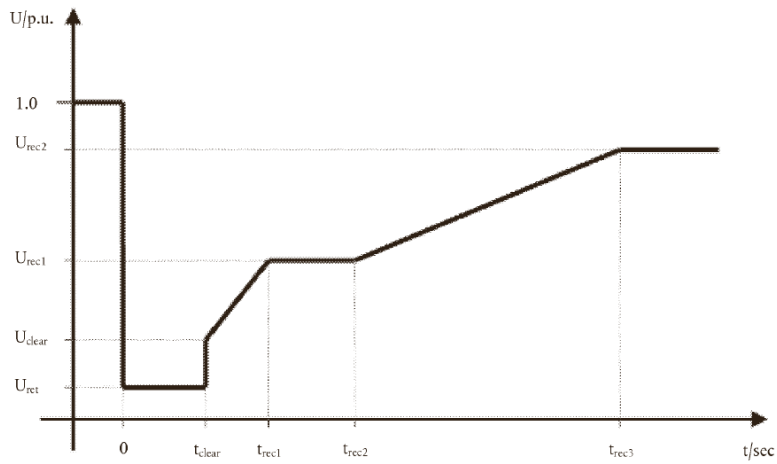

Figure 16 – Fault ride through capability of a power generating module [2]

Voltage parameters (pu)		Time parameters (seconds)	
U_{ret}	0.05 – 0.15	t_{clear}	0.14 – 0.15 (or 0.14 – 0.25 if system protection and secure operation so require)
U_{clear}	U_{ret} – 0.15	t_{rec1}	t_{clear}
U_{rec1}	U_{clear}	t_{rec2}	t_{rec1}
U_{rec2}	0.85	t_{rec3}	1.5 – 3.0

Table 18 – Parameters for Figure 16 for fault ride through capability of power park modules [2]

5.1.2.2 POST – FAULT RECOVERY

D1.1 The OWF should recover after faults while complying with:

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- a voltage criterion when the post-fault active power recovery begins,
- a minimum and maximum allowed time for active power recovery;
- a magnitude and accuracy for active power recovery.

D1.5 The OWF shall be capable of returning the active power from a limited operating point to the pre – fault active power level minus 10% (e.g. 100% - 10% = 90%) with a ramp rate of 200%/s [21]. Active power oscillations shall be acceptable provided that:

- The total active energy delivered during the period of the oscillations is at least that which would have been delivered if active power was constant.
- The oscillations are adequately damped.
- Limitations of the transmission system are regarded.

5.1.2.3 FAST FAULT CURRENT DURING OFFSHORE FAULTS

D1.1 OWF should be capable of providing specified fault current at the connection point in case of symmetrical and asymmetrical faults. The characteristics of the fault current will be specified. OWF should operate accordingly in order not to prevent clearance of offshore AC faults by the protection system.

D1.5 According to [1] and [2] the OWF shall be capable of providing fast fault current at the OWF connection point either by:

- Ensuring the supply of the fast fault current at the OWF connection point, or
- Measuring voltage deviations at the terminals of the individual WTs of the OWF and providing a fast fault current at the terminals of WTs.

OWF shall be capable of providing active and reactive currents both in positive and negative sequences. The exact short circuit infeed requirements need to be defined considering the protection strategy and the basic design (equipment rating) of the OWF and OTS.

5.1.2.4 DC FAULT RIDE THROUGH

D1.1 OWF should be capable of coordinating with the DC grid control and protection systems in order to modify its output during faults, provided that the DC fault can be detected by the OWF. Fault detection means and detailed response (modification of output) of the OWF will be specified in related WPs.

D1.5 Not quantifiable. In addition to D1.1, in case of a radial connection the OWF shall be capable of performing secure turn-off (It is assumed that DC faults will be permanent for radial connections). In case of a meshed DC connection, OWF shall be capable of performing fault ride through for securely cleared DC faults, as same as the response to onshore AC fault.

5.1.2.5 ONSHORE AC FAULT RIDE THROUGH

D1.1 OWF should be capable of modifying its output during onshore AC faults, provided that the onshore AC fault can be detected by the OWF. Fault detection means and detailed response (modification of output) of the OWF will be specified in related WPs.

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D1.5 Unintended interruptions of the active power flow from the OWF into the transmission system have to be handled by the OWF. Such interruptions can occur due to any onshore grid event or transmission system fault which causes a full or partial blocking of the transmission system power flow. Within the lower abnormal range, the transmission system can – for a limited duration – block active power flow from the OWF to a value which is less than the OWF power output reference. Such power limits are considered as "unintended interruptions". In the lower emergency range, the OWF is not expected to remain connected, and can results in a complete trip of the plant (OWF + OTS). As an example, the maximum time to perform the active power modification in order to avoid the DC voltage to surpass the maximum value, can be as low as 10 ms for severe faults leading to almost zero active power injection into the grid.

5.1.3 VOLTAGE STABILITY

5.1.3.1 OPERATIONAL VOLTAGE RANGES

D1.1 OWF should be capable of staying connected to the network and operating within the ranges of the network voltage at the connection point, when the voltage deviates from 1 pu for the specified time periods.
OWF should be capable of automatic disconnection based on agreed terms and settings for automatic disconnection.

D1.5 A DC – connected power park module shall be capable of staying connected to the network and operable within the voltage ranges listed in Table 19 and Table 20.

Voltage Range	Time period for operation
0.85 pu – 0.90 pu	60 minutes
0.90 pu – 1.10 pu	Unlimited
1.10 pu – 1.118 pu	Unlimited, unless specified otherwise by the relevant system operator, in coordination with the relevant TSO
1.118 pu – 1.15 pu	To be specified by the relevant system operator, in coordination with the relevant TSO

Table 19 – Minimum time periods for which a DC – connected power park module shall be capable of operating for different voltages where the base voltage for pu values is from 110 kV to 300 kV

Voltage Ranges	Time period for operation
0.85 pu – 0.90 pu	60 minutes
0.90 pu – 1.05 pu	Unlimited
1.05 pu – 1.15 pu	To be specified by the relevant system operator, in coordination with the relevant TSO. Various sub – ranges of voltage withstand capability can be specified

Table 20 – Minimum time periods for which a DC – connected power park module shall be capable of operating for different voltages where the base voltage for pu values is from 300 kV to 400 kV

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5.1.3.2 REACTIVE POWER CONTROL

D1.1 OWF should meet specified reactive power control requirements. As all requirements in this chapter, applicability of this requirement will be dependent on technology and system operator and related WPs will address quantification of this requirement.

D1.5

VSC Quantifiable but a project specific requirement.

DRU When the OWF is not connected via the HVDC (i.e. no HVDC power flow), it shall be possible to control the WTGs output voltage/reactive power to:

- Support the OTS in controlling the voltage magnitude at the interface between OWF and OTS.
- Avoid any unnecessary reactive power flow between WTGs in the OWF to prevent overloading of collector cabling etc. (This applies in all modes of operation).

Note: When power is being transmitted via the HVDC connection, the voltage at the OTS/OWF interface cannot be controlled independently of the active power flow in the HVDC.

STEADY STATE VOLTAGE/REACTIVE POWER CONTROL

When the OWF is not connected via the HVDC (i.e. no HVDC power flow), it shall be possible to control the WTG output voltage/reactive power in such way to:

a. Support the OTS in controlling the voltage magnitude at the interface between OWF and OTS.

b. Avoid any unnecessary reactive power flow between WTGs in the OWF to prevent overloading of collector cabling etc. (This applies in all modes of operation).

Note: When power is being transmitted via the HVDC connection, the voltage at the OTS/OWF interface cannot be controlled independently of the active power flow in the HVDC.

DYNAMIC VOLTAGE CONTROL

When the OWF is not connected via the HVDC (i.e. no HVDC power flow), it shall be possible to control the WTG output voltage/Reactive power to a new set point with a rise time of 1 second from the point where the set point is received by the OWF.

Note: When power is being transmitted via the HVDC connection, the voltage at the OTS/OWF interface cannot be controlled independently of the active power flow in the HVDC.

5.1.4 POWER OSCILLATION DAMPING

D1.1 OWF should be capable of contributing to damping of power oscillations. The voltage and reactive power control characteristics of OWF must not adversely affect the damping of power oscillations.

OWF should be able to modulate its active power output as response to a signal for provision of damping via active power to the onshore AC grid.

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D1.5 Quantifiable but a project specific requirement.

For example, OWF shall have the capability to modulate its active power output for a sinusoidal waveform in the frequency range 0.3 Hz to 2 Hz [21] with a magnitude of 0.1pu [15]. It is importan to note that the priority here is given to the capability of the OWF to provide the necessary active power modulation. Impact and benefit of this capability on th onshore synchronous area stability will be investigated with a second priority. The OWF should generally not introduce additional frequencies into the onshore grid and interact with existing generators in an undesired manner.

5.1.5 START – UP

D1.1 OWFs should be able to perform necessary control actions, in coordination with Offshore HVDC Terminal, in order to start-up the offshore AC grid.

D1.5 Not quantifiable.

5.1.6 AUTO – SYNCHRONOUS OPERATION

D1.1 In case there is no reference available to be synchronized with (e.g. VSC-HVDC or umbilical AC line), OWF should be able to perform auto-synchronous operation, where the OWF forms and controls AC grid voltage in its collector system. OWF should be able to switch between synchronous and auto-synchronous operation.

D1.5 Not quantifiable.

5.1.7 POWER QUALITY

D1.1 OWF should ensure that their connection to the network does not result in a level of distortion or fluctuation of the supply voltage on the network at the connection point.

D1.5

VSC Quantifiable but not available yet. Control interaction among WTGs shall not result in harmonic instability in the offshore AC grid. OWF controllers shall not contribute to amplification of resonance in the offshore AC grid.

DRU The OWF MV collector system shall comply with IEC 61000-2-4 class 3 compatibility requirements.

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5.2 REQUIREMENTS FOR OFFSHORE HVDC TERMINALS

5.2.1 OPERATIONAL RANGES

5.2.1.1 OFFSHORE AC LINK VOLTAGE RANGE

D1.1 Offshore HVDC Terminal should be capable of staying connected and operable at specified offshore AC voltage levels. Automatic disconnection will be allowed at specified offshore AC voltage levels.

D1.5
VSC Minimum time periods for which a remote – end HVDC converter station shall be capable of operating for different voltages are listed in Table 21 and Table 22

Voltage Range	Time period for operation
0.85 pu – 0.90 pu	60 minutes
0.90 pu – 1.10 pu	Unlimited
1.10 pu – 1.12 pu	Unlimited, unless specified otherwise by the relevant system operator, in coordination with the relevant TSO
1.12 pu – 1.15 pu	To be specified by the relevant system operator, in coordination with the relavant TSO

Table 21 – Minimum time periods for which a remote – end HVDC converter station shall be capable of operating for different voltages without disconnecting from the network where the voltage base for pu values is from 110 kV to 300 kV [1]

Voltage Range	Time period for operation
0.85 pu – 0.90 pu	60 minutes
0.90 pu – 1.05 pu	Unlimited
1.05 pu – 1.15 pu	To be specified by the relevant system operator, in coordination with the relevant TSO. Various sub – ranges of voltage withstand capability may be specified

Table 22 – Minimum time periods for which a remote – end HVDC converter station shall be capable of operating for different voltages without disconnecting from the network where the voltage base for pu values is from 300 kV to 400 kV [1]

DRU The requirements of 5.1.3.1. operational voltage ranges apply here.

5.2.1.2 OFFSHORE AC LINK FREQUENCY RANGE

D1.1 Offshore HVDC Terminal should be capable of staying connected and operable at specified offshore AC frequency levels. Automatic disconnection will be allowed at specified frequency levels.

D1.5
VSC According to the NC-HVDC grid code [1], the AC frequency of the HVDC terminal is listed in Table 23.

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Frequency Range	Time period for operation
47.0 Hz – 47.5 Hz	20 seconds
47.5 Hz – 49.0 Hz	90 minutes
49.0 Hz – 51.0 Hz	Unlimited
51.0 Hz – 51.5 Hz	90 minutes
51.5 Hz – 52.0 Hz	15 minutes

Table 23 – Minimum time periods for the 50 Hz nominal system for which a PPM shall be capable of operating for different frequencies without disconnecting from the network [1]

DRU The requirements of 5.1.1.2 operational frequency range apply here.

5.2.1.3 OFFSHORE RATE OF CHANGE OF FREQUENCY LINK

D1.1 Offshore HVDC Terminal should be capable of staying connected and operable if the network frequency changes at up to a specified rate.

D1.5

VSC The requirements of 5.1.1.3 operational rate of change of frequency apply here.

DRU Not applicable, because DRU can stay connected at any frequency level.

5.2.1.4 OFFSHORE ACTIVE POWER EXCHANGE

D1.1 Offshore HVDC Terminal should be capable of adjusting the transmitted active power up to its maximum HVDC active power transmission capacity in each direction following an instruction.
Offshore HVDC Terminal should be capable of adjusting the ramping rate of active power variations within its technical capabilities in accordance with instructions sent by relevant TSOs.

D1.5

VSC Not quantifiable.

DRU Not applicable for DRU because power flow is unidirectional.

5.2.2 ROBUSTNESS AND STABILITY

D1.1 Offshore HVDC Terminal should allow for necessary control actions to prevent or help damping electrical oscillations in the offshore AC grid.

D1.5

VSC Not quantifiable. In addition to D1.1, control interaction between WTGs and VSC terminal shall not result in harmonic instability in the offshore AC grid. The controllers shall not contribute to amplification of resonance in the offshore AC grid.

DRU Not applicable for DRU, requirement is transferred to OWFs, see therefore section 5.1.2 robusteness and control during short – circuit faults.

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5.2.3 OFFSHORE BEHAVIOUR DURING SHORT – CIRCUITS FAULTS

5.2.3.1 OFFSHORE AC FAULT RIDE THROUGH

D1.1 Offshore HVDC Terminal should stay connected when its connection point voltage stays within a specified voltage-time series profile.

D1.5

VSC A list of the parameters is displayed in Table 24 and Figure 17. Each relevant TSO can specify their parameters between these ranges.

Voltage parameters [pu]		Time parameters (seconds)	
U_{ret}	0.00 – 0.30	t_{clear}	0.14 – 0.25
U_{rec1}	0.25 – 0.85	t_{rec1}	1.5 – 2.5
U_{rec2}	0.85 – 0.90	t_{rec2}	t_{rec1} – 10.0

Table 24 – Parameter range for the fault ride through capability at the connection point [1]

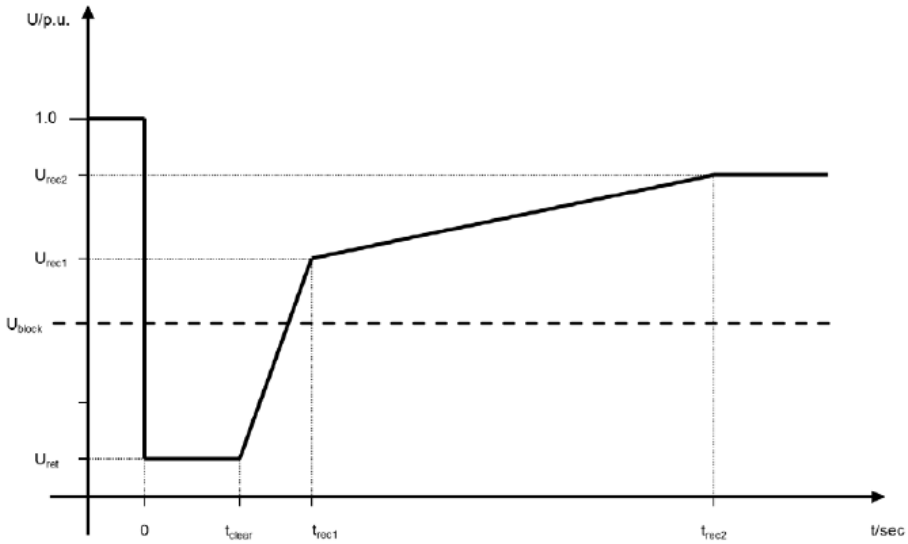

Figure 17 – Fault ride through capability curve for an HVDC converter station at the connection point [1]

The relevant TSO shall also specify fault ride through capability for asymmetrical faults as well.

DRU DRU stays connected. Requirements from 5.1.2.1 offshore AC fault ride through apply here for the DRU.

5.2.3.2 OFFSHORE HVDC TERMINAL MUST RESPOND TO OFFSHORE AC GRID FAULTS

D1.1 Offshore HVDC Terminal should have the capability to provide fault current with specified characteristics (e.g. active/reactive positive/negative sequence) at a connection point in case of symmetrical (3-phase) and

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asymmetrical faults. It should behave in accordance with protection practices during offshore AC faults such that as minimum it will not prohibit flow of fault currents at its terminals, up to its design current rating. In other words, offshore HVDC Terminal should operate accordingly in order not to prevent clearance of offshore AC faults by the protection system. It should also be equipped with necessary schemes to protect itself against overcurrent and overvoltage. Finally, it should be able to perform specified fault-recovery, where details of fault-recovery (e.g. ramp-up of power, voltage) will be specified in related WPs.

D1.5

VSC Quantifiable, the same for the connected OWF as in 5.1.2.3 fast fault current during offshore fault.

DRU Not applicable.

5.2.4 OFFSHORE START – UP REQUIREMENTS

5.2.4.1 START – UP OF OFFSHORE AC GRID

D1.1 Offshore HVDC Terminal should be able to perform necessary control actions, in coordination with OWFs, switching (e.g. connecting and disconnecting AC umbilical line and/or the DRU in case of DRU-HVDC case) in order to start up the offshore AC grid.

D1.5

VSC Not quantifiable.

DRU Not quantifiable.

5.2.4.2 CAPABILITY TO CONTROL THE OFFSHORE AC GRID VOLTAGE

D1.1 Offshore HVDC Terminal should be capable to control the offshore AC voltage by itself, by proper coordination with OWFs or by proper combination thereof.

D1.5

VSC Not quantifiable.

DRU Requirement is transferred to the connected OWF. Requirements from 5.1.3.2 reactive power control apply here.

5.2.4.3 OFFSHORE POWER QUALITY

D1.1 Offshore HVDC Terminal characteristics should not result in a level of distortion or fluctuation of the supply voltage or other electrical quantities in the offshore AC network, at the connection point, exceeding specified levels.

D1.5 The IEC 61000-2-4 class 3 compatibility requirements will be the main reference for the corresponding studies within PROMOTioN

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5.3 DISCUSSIONS

In the process of developing D1.5 some concerns and discussion items were addressed. Therefore in this section a discussion is drafted about the consequences for installing a DRU terminal, FSM and LFSM mode requirements in a power electronics dominated system and fast fault current during offshore faults.

From the quantification process for the requirements for offshore HVDC terminals can be concluded that for DRU terminals a significant amount of requirements are transferred to the OWF. As a consequence complexity in the OWF regarding operation, control and communication will increase. Some issues arise regarding the transfer of these requirements.

- OWFs might face an increase in costs in order to fulfill the requirements when the OWF is DRU connected.
- Since a DRU can be seen as one common unit together with the OWF, issues could arise about the ownership of the Remote-End HVDC Converter Stations. In a number of EU countries the TSO is responsible for the grid connection including the Remote-End HVDC Converter station, development of a DRU could spark discussions about the scope of grid connection systems owned by the TSO, and increased responsibilities for OWFs.

Regarding the FSM and LFSM mode requirements, these could be irrelevant for a system consisting of 100% power electronics where there is no link between active power and frequency. Although important to keep in mind, questions regarding how to deal with the integration of massive power electronic devices are dealt with in the MIGRATE project [17] and is not dealt with in PROMOTioN project.

OWF farms are required to provide fast fault current during offshore faults. A question was raised if there are alternative ways from a protection system perspective to deal with offshore faults.

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6 MESHED OFFSHORE GRID – OFFSHORE CONSUMPTION

As explained in D1.1 no specific requirements for offshore load were developed as possible connections will be evaluated on a case-by-case basis. Therefore quantification of requirements is not defined.

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7 MESHED OFFSHORE GRID – OPERATION

Chapter 7 of D1.1 details the operational requirements of a DC Meshed Offshore Grid, including the grid protection system. Many of these requirements are purely qualitative, such as selectivity, sensitivity, reliability of equipment. Further, as mentioned in D1.1, the requirements are not based on any existing grid code and significant changes and additions may occur during progress of PROMOTioN project. NC-HVDC and NC-RFG do not specify the operational requirements for the DC side of the HVDC terminals. Therefore, if requirements are quantifiable this will not be based on existing grid codes and will therefore be exemplary.

7.1 REQUIREMENTS FOR HVDC TERMINALS

7.1.1 OPERATIONAL RANGES

7.1.1.1 HVDC VOLTAGE RANGE

D1.1 HVDC Terminal should be capable of staying connected and operable at specified DC link voltage levels and time periods. Automatic disconnection will be allowed at specified HVDC voltage levels.

D1.5 HVDC terminal shall be capable of normal operation in a voltage range around the nominal voltage, for instance ± 5% of the nominal DC link voltage (0.95 pu – 1.05 pu) as shown in Figure 18 [13].

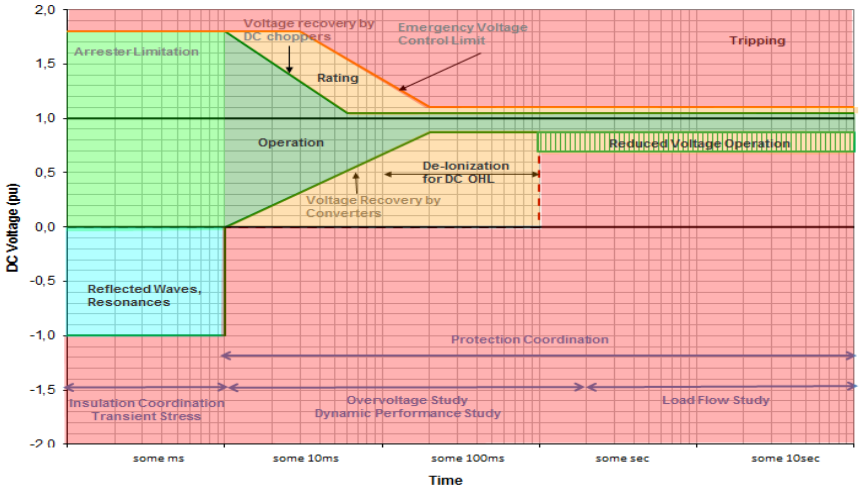

Figure 18 – Temporary DC pole to ground voltage profiles in DC Grids. The time and voltage limits depend on technology and topology of the DC Grid. The scales are used for illustration only [12].

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7.1.1.2 RATE OF CHANGE OF DC VOLTAGE[8]

D1.1 HVDC Terminal should be capable of staying connected and operable if the HVDC voltage changes at up to a specified rate.

D1.5 Quantifiable but not available yet.

7.1.2 POWER AND DC VOLTAGE RESPONSE

7.1.2.1 DC VOLTAGE RESPONSE PROCESSING

D1.1 HVDC Terminal should be capable of receiving a measured DC voltage (or power [9]) signal from a connection point, within a specified time period from sending to completion of processing the signal for activation of the response. DC voltage will typically be measured at the HVDC Terminal's DC side.

D1.5 Specified delay should be quantifiable but not available yet.

7.1.2.2 DC VOLTAGE RESPONSE ACTIVATION

D1.1 HVDC Terminals should be capable of activating a power DC voltage response with an initial delay.
HVDC Terminals should be capable of providing active power frequency response for a specified duration.

D1.5 This initial delay and specified duration could be quantified. These values need to be agreed upon in future grid codes and should be addressed within PROMOTioN project. Recommendations to future grid codes will be provided by WP11.

7.1.2.3 DC VOLTAGE RESPONSE PARAMETERIZATION

D1.1 HVDC Terminals should be able to provide active power response based on a set of specified parameters, which allow for the calculation of the active power (or DC current) as a function of the DC voltage (or power [10]).

D1.5 Quantifiable but not available yet. In addition to D1.1, this should be based on operational agreements between relevant TSO's.

7.1.2.4 COORDINATION WITH OWFS FOR ONSHORE FREQUENCY SUPPORT

D1.1 For an Offshore HVDC Terminal connecting OWFs, with regards to DC voltage response, Offshore HVDC Terminal and OWF should agree on the technical requirements to achieve necessary support for DC voltage response. These requirements are further described in chapter 4 and 5 of this document.

D1.5 Not quantifiable.

[8] Updated from D1.1 see Appendix B
[9] Updated from D1.1 see Appendix B
[10] Updated from D1.1 see Appendix B

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7.1.3 ROBUSTNESS AND STABILITY

D1.1 HVDC Terminal should be capable of transitioning to a new stable operating point for a minimum change in active power flow and voltage level, during and after any planned or unplanned change in the HVDC system.[11]

D1.5 Not quantifiable.

7.1.4 HVDC TERMINAL BEHAVIOUR DURING SHORT – CIRCUIT FAULTS

7.1.4.1 HVDC TERMINAL RESPONSE TO DC GRID FAULTS

D1.1

- HVDC Terminal should be equipped with necessary schemes to protect it against overcurrent and under and overvoltage in case of DC grid faults.
- HVDC Terminal should be capable of fast recovery from securely cleared faults within parts of the meshed HVDC system (i.e. DC link faults), where details of this capability should be subject to coordination and agreements on protection schemes and settings.
- HVDC Terminal should be equipped with necessary schemes to reconnect itself after a DC grid fault.
- HVDC Terminal should be equipped with necessary schemes to communicate the fault information (e.g. fault status, DC link voltage, etc.) to OWFs, which may be connected at its AC side.

D1.5 Quantifiable but not available yet. Relevant TSO's need to define a DC fault ride through capability curve specifying the transient voltage requirements at the DC terminal.

7.1.5 START – UP REQUIREMENTS OF HVDC TERMINALS

7.1.5.1 START – UP OF DC GRID

D1.1 Within the DC grid, some HVDC terminals should be able to perform necessary control actions in order to start-up the DC grid.[12]

D1.5 Not quantifiable.

7.1.6 POWER QUALITY

D1.1 HVDC Terminal operation should not exceed specified levels of distortion, fluctuation of voltage supply and other electrical quantities at its DC side connection point.

D1.5 Not quantifiable yet.

[11] Updated from D1.1 see Appendix B
[12] Updated from D1.1 see Appendix B

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7.2 DC PROTECTION AND CONTROL REQUIREMENTS

Protection and control requirements depend on the chosen protection methodologies/philosophies and the connected grids. Since these protection methodologies/philosphies are screened and compared in WP4 (D4.2), it is not possible yet at this stage of the PROMOTioN project, to quantify specific requirements for the protection and control of the HVDC system. Based on how the system is protected, different consequences will be put on the AC system. The following general DC protection requirements, as mentioned in D1.1, are quantified when applicable within chapter 4, 5 and 7.1:

- Requirements imposed by onshore AC system (see chapter 4)
    - Maximum loss of active power infeed and maximum duration
    - Reactive power supply during dc faults
    - Other connection constraints (e.g. defined in the HVDC Grid code)
- Requirements imposed by offshore AC wind farm collector grids (see chapter 5)
    - Requirements imposed by wind farms/ac collector grids for wind farms
- Requirements imposed by DC system (see paragraph 7.1)
    - DC voltage collapse/Controllability of the DC voltage

7.3 DISCUSSIONS

In the process of developing D1.5 some concerns and discussion items were addressed. Therefore in this section a discussion is drafted about the unknows in the operation of an HVDC offshore grid, future standards for power quality and operating voltage level(s).

From the quantification process for the operational requirements for offshore HVDC terminals can be concluded that for most requirements quantifications are not available or are qualitative in nature. Therefore, the question how to make these requirements work in a meshed grid with several operators and owners remains an open item.

Further, an issue was raised about the operation of a meshed HVDC offshore grid. As listed in chapter 4, TSO's should specify how an HVDC system should be capable of modifying the transmitted active power infeed in case of distrubances into one or more AC networks to which it is connected. Therefore a request for intervention in one onshore grid will affect several onshore grids which are interconnected via the MOG, because the other grids should balance their power to handle the active power infeed change in the first grid. Thus several TSOs should participate and have solidarity agreements for supporting each other. This is required because disturbances may cause supply outage in the first grid, i.e. the active power change can be longer lasting than short-term. Therefore it is necessary to develop some sort of Voltage/Power balancing grid code for operationg HVDC MOG's.

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Regarding power quality experience is lacking and should be gained. In the future standards need to be developed by organizations such as CIGRE and CENELEC. WP11 is responsible organizing exchanges with these organizationis and integrate their lessons learned into the recommondations of PROMOTioN project.

One issue that needs further investigation is the connenction of DC lines operation at different voltage levels. For a meshed offshore grid, like the frequency of 50 Hz in the AC grid, the voltages must be the same otherwise DC transformers need to be integrated in the grid as well. This is more a grid design than an operation question and will be part of the roadmap development in WP1 and WP12.

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8 NON – FUNCTIONAL REQUIREMENTS

As these requirements are set by stakeholders outside the consortium, it is not possible for the consortium to set these requirements. Work Package 7 is investigating these requirements.

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APPENDIX A

DETERMINATION OF TYPE OF POWER – GENERATING UNIT

The power – generating modules within the following categories shall be considered as significant [2]:

- Type A, connection point below 110 kV and maximum capacity of 0.8 kW or more.
- Type B, connection point below 110 kV and maximum capacity at or above a threshold proposed be each relevant TSO.
- Type C, connection point below 110 kV and maximum capacity at or above a threshold specified by each relevant TSO.
- Type D, connection point at 110 kV or above. A power – generating module is also Type D if its connection point is below 110 kV and its maximum capacity is at or above a threshold.

Synchronous areas	**Limit for maximum capacity threshold from which a power – generating module is of type B**	**Limit for maximum capacity threshold from which a power – generating module is of type C**	**Limit for maximum capacity threshold from which a power – generating module is of type D**
Continental Europe	1 MW	50 MW	75 MW
Great Britain	1 MW	50 MW	75 MW
Nordic	1.5 MW	10 MW	30 MW
Ireland and Northern Ireland	0.1 MW	5 MW	10 MW
Baltic	0.5 MW	10 MW	15 MW

Table 25 – Limits for thresholds for type B, C and D power generating modules

FREQUENCY RANGES

The HVDC system must remain operable within the frequency ranges and time periods listed in Table 26.

Frequency range	**Time period of operation**

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47.0 Hz – 47.5 Hz	60 seconds
47.5 Hz – 48.5 Hz	To be specified by the relevant TSO but longer than established times for generation and demand and longer than DC – connected PPMs
48.5 Hz – 49.0 Hz	To be specified by the relevant TSO but longer than established times for generation and demand and longer than DC – connected PPMs
49.0 Hz – 51.0 Hz	Unlimited
51.0 Hz – 51.5 Hz	To be specified by the relevant TSO but longer than established times for generation and demand and longer than DC – connected PPMs
51.5 Hz – 52.0 Hz	To be specified by the relevant TSO but longer than for DC – connected PPMs

Table 26 – HVDC system frequency ranges [1]

The frequency ranges and time period of operation for generation and demand are listed in Table 27.

	Frequency range	**Time period of operation**
Continental Europe	47.5 Hz – 48.5 Hz	To be specified by the relevant TSO but no less than 30 minutes
	48.5 Hz – 49.0 Hz	To be specified by the relevant TSO but no less than 30 minutes
	49.0 Hz – 51.0 Hz	Unlimited
	51.0 Hz – 51.5 Hz	30 minutes
Nordic	47.5 Hz – 48.5 Hz	30 minutes
	48.5 Hz – 49.0 Hz	To be specified by the relevant TSO but no less than 30 minutes
	49.0 Hz – 51.0 Hz	Unlimited
	51.0 Hz – 51.5 Hz	30 minutes
GB	47.0 Hz – 47.5 Hz	20 seconds
	47.5 Hz – 48.5 Hz	90 minutes
	48.5 Hz – 49.0 Hz	To be specified by the relevant TSO but no less than 90 minutes
	49.0 Hz – 51.0 Hz	Unlimited
	51.0 Hz – 51.5 Hz	90 minutes
	51.5 Hz – 52.0 Hz	15 minutes
Ireland and Northern Ireland	47.5 Hz – 48.5 Hz	90 minutes

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	48.5 Hz – 49.0 Hz	To be specified by the relevant TSO but no less than 90 minutes
	49.0 Hz – 51.0 Hz	Unlimited
	51.0 Hz – 51.5 Hz	90 minutes
Baltic	47.5 Hz – 48.5 Hz	To be specified by the relevant TSO but no less than 30 minutes
	48.5 Hz – 49.0 Hz	To be specified by the relevant TSO but no less than 30 minutes
	49.0 Hz – 51.0 Hz	Unlimited
	51.0 Hz – 51.5 Hz	To be specified by the relevant TSO but no less than 30 minutes

Table 27 – Frequency ranges for generation and demand [2]

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APPENDIX B – CHANGED ITEMS FROM D1.1

Old: 4.2.4.2 INTERACTION BETWEEN HVDC SYSTEMS AND OTHER AC CONNECTED PLANTS AND EQUIPMENT

The HVDC converter controllers and filters must be designed to ensure that no negative interaction occurs between stations and nearby electrical equipment.

The relevant TSO may specify transient levels of performance associated with events for the individual HVDC system or collectively across commonly impacted HVDC systems. This specification may be provided to protect the integrity of both TSO equipment and equipment of grid users in order to comply with the relevant standards and codes.

New: 4.2.4.2 INTERACTION BETWEEN HVDC SYSTEMS AND OTHER AC CONNECTED PLANTS AND EQUIPMENT

The HVDC converter controllers and filters must be designed to ensure that no adverse interaction occurs between stations and nearby electrical equipment.

The relevant TSO may specify transient levels of performance associated with events for the individual HVDC system or collectively across commonly impacted HVDC systems. This specification may be provided to protect the integrity of both TSO equipment and equipment of grid users in order to comply with the relevant standards and codes.

Old: 4.2.6.1 BLACK START

An HVDC system may provide black start services to a TSO. An HVDC system with black start capability must be able, in case one converter station is energised, to energise the busbar of the AC-substation to which another converter station is connected, within a time frame after shut down determined by the relevant TSOs. The HVDC system must be able to synchronise within specified frequency limits and voltage limits. The black start availability, capability and the associated operational procedure must be specified with the relevant TSO.

New: 4.2.6.1 BLACK START

An HVDC system may provide black start services to a TSO. An HVDC system with black start capability must be able, in case one converter station is energised, to energise the busbar of the AC-substation to which another converter station is connected, within a time frame after shut down determined by the relevant TSOs. The HVDC system must be able to synchronise within specified frequency limits and voltage limits. The black start availability, capability and the associated operational procedure must be specified by the relevant TSO.

Old: 5.1.1.5 ACTIVE POWER CONTROL

OWFs should be capable of adjusting an active power setpoint in line with instructions given to the OWF owner by the relevant system operator (constrained by available power). Tolerance (depending on the availability of wind resource) applying to the new setpoint and the time period within which it must be reached will be specified. Minimum and maximum limits on rates of change of active power

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output (ramping limits) in both increases and decreases of active power output for OWF will be specified.

New: 5.1.1.5 ACTIVE POWER CONTROL

OWFs should be capable of adjusting an active power setpoint in line with instructions given to the OWF operator by the relevant system operator (constrained by available power). Tolerance (depending on the availability of wind resource) applying to the new setpoint and the time period within which it must be reached will be specified. Minimum and maximum limits on rates of change of active power output (ramping limits) in both increases and decreases of active power output for OWF will be specified.

Old: 5.1.1.6 FREQUENCY RESPONSE PROCESSING

OWF should be capable of receiving a measured frequency signal from a connection point in the (typically onshore) synchronous area to which frequency response is being provided, within a specified time period from sending to completion of processing the signal for activation of the response. Frequency will be measured at the connection point in the synchronous area to which frequency response is being provided. OWF connected via HVDC systems which connect with more than one control area should be capable of delivering coordinated frequency control as specified by the relevant system operator.

New: 5.1.1.6 FREQUENCY RESPONSE PROCESSING

OWF shall be capable of receiving an onshore frequency signal (measured at the onshore synchronous area connection point and sent by the onshore converter or master controller).

OWFs connected via HVDC systems which connect with more than one control area should be capable of delivering coordinated frequency control which will be separately specified.

OWFs that are directly connected to onshore synchronous area (for instance via AC offshore interconnection to an AC-connected OWF) will respond without need for communication.

Old: 5.1.1.8 FREQUENCY RESPONSE PARAMETERIZATION

OWFs should be able to provide active power frequency response based on a set of specified parameters which allow for the calculation of the active power as a function of the frequency. The combination of choice of the parameters specified should take possible technology-dependent limitations into account.

New: 5.1.1.8 FREQUENCY RESPONSE PARAMETERIZATION

OWFs should be able to provide active power frequency response based on a set of specified parameters which allow for the calculation of the active power as a function of the frequency. The combination of choice of the parameters specified should take potential technology-dependent limitations into account

Old: 7.1.1.2 OFFSHORE RATE OF CHANGE OF DC VOLTAGE

New: 7.1.1.2 RATE OF CHANGE OF DC VOLTAGE

Old: 7.1.2.1 DC VOLTAGE RESPONSE PROCESSING

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HVDC Terminal should be capable of receiving a measured DC voltage (or energy) signal from a connection point, within a specified time period from sending to completion of processing the signal for activation of the response. DC voltage will typically be measured at the HVDC Terminal's DC side.

New: 7.1.2.1 DC VOLTAGE RESPONSE PROCESSING

HVDC Terminal should be capable of receiving a measured DC voltage (or power) signal from a connection point, within a specified time period from sending to completion of processing the signal for activation of the response. DC voltage will typically be measured at the HVDC Terminal's DC side.

Old: 7.1.2.3 DC VOLTAGE RESPONSE PARAMETERIZATION

HVDC Terminals should be able to provide active power response based on a set of specified parameters which allow for the calculation of the active power (or DC current) as a function of the DC voltage (or energy).

New: 7.1.2.3 DC VOLTAGE RESPONSE PARAMETERIZATION

HVDC Terminals should be able to provide active power response based on a set of specified parameters which allow for the calculation of the active power (or DC current) as a function of the DC voltage (or power).

Old: 7.1.3 ROBUSTNESS AND STABILITY

HVDC Terminal should be capable of finding stable operation points for a minimum change in active power flow and voltage level, during and after any planned or unplanned change in the HVDC system.

New: 7.1.3 ROBUSTNESS AND STABILITY

HVDC Terminal should be capable of transitioning to a new stable operation point for a minimum change in active power flow and voltage level, during and after any planned or unplanned change in the HVDC system.

Old: 7.1.5.1 START – UP OF DC GRID

HVDC Terminal should be able to perform necessary control actions in order to start-up the DC grid.

New: 7.1.5.1 START – UP OF DC GRID

Within the DC grid some HVDC terminals should be able to perform necessary control actions in order to start-up the DC grid.

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APPENDIX C – MAXIMUM POWER LOSS

Maximum loss of power infeed and duration: maximum power infeed at the point(s) of common coupling and duration which an AC system can lose. Figure 19 shows an example of maximum loss of power infeed and associated duration for a given AC system. The maximum loss of infeed is split into three parts, i.e., 'transient' loss, 'temporary loss' and 'permanent loss'. This curve can be interpreted in a similar fashion as the voltage against time fault ride through curve for a wind farm (i.e., the maximum loss of power P_x, including the restoration procedure, should not be sustained for a period longer than t_x).

- The *transient loss* is the loss P_1 which is associated with the lowest timescales (e.g.., t_1<20 ms (1 fundamental cycle)). This time frame is well within the first zone protection at the AC side. This time frame also corresponds to a HVDC grid protection strategy which clears the faults near instantaneously (e.g. without de-energisation of (parts of) the HVDC grid).
- The *temporary loss* is the loss P_2 which is associated with a temporary stop of power in the range of electromechanical transients of the AC system (e.g., t_2 ~ hundreds of ms). This time frame corresponds to a longer outage at the AC side, still cleared by the protection system (e.g. second zone protection). From a DC protection point of view, such time frame corresponds to protection strategies which involve de-energisation and restoring the DC voltage in (parts of) the HVDC grid.
- The *permanent loss* is the loss P_3 is defined in the current grid code (before the frequency deviation falls outside the limits for more than a certain amount of time), and the duration is normally considered longer than t_3[11] Different synchronous zones have defined their own Pmax values[13]. For continental Europe, the value of 3000 MW corresponds to the loss of the two largest generators. This time frame corresponds to losing one or more DC terminals for an indefinite period of time.

These definitions correspond to the ones used in the CENELEC WG TX-8C WG 06 Brochure (cf. Section 3). However, contrary to the definitions used in CENELEC, power flow restoration to a new stable operating point should be included for P_1 and P_2.

[13] As an example, in the UK grid code. "That level of loss of power infeed risk which is covered over long periods operationally by frequency response to avoid a deviation of system frequency outside the range 49.5Hz to 50.5Hz for more than 60 seconds. Until 31st March 2014, this is 1320MW. From April 1st 2014, this is 1800MW."

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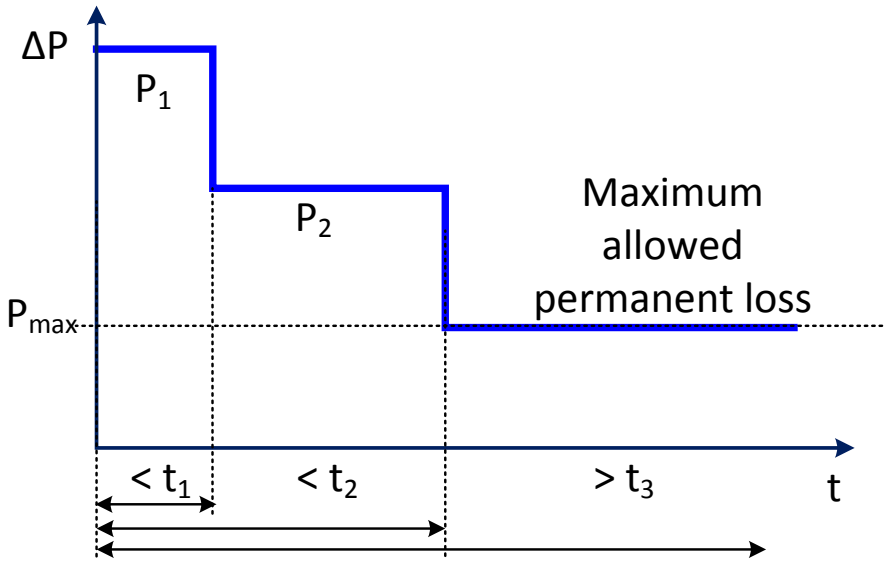

Figure 19 – Maximum loss of power infeed and duration of an AC grid

Depending on the configuration between the AC and DC grids, maximum loss of power infeed and duration can be further defined as maximum loss of power infeed and duration at a node (one point of common coupling), to a synchronous zone and to a control area. The ΔP curve also considers the possible outage of a single converter.

Example associated with the use of these curves:

Several fault clearing strategies have been proposed in the literature. An initial classification in [14] is given in Figure 20:

This classification focuses on the impact of the protection strategy on the power system elements [14]

- Type (a) line protection : impact only on the faulty line
- Type (b) line+ protection : impact on the faulty line and on the closest MMC converter
- Type (c) open grid protection : open all the breakers at a bus
- Type (d) grid splitting protection : disconnect the faulty zone (containing DC sub-grids)
- Type (e) low-speed HVDC grid protection : impact on the entire grid

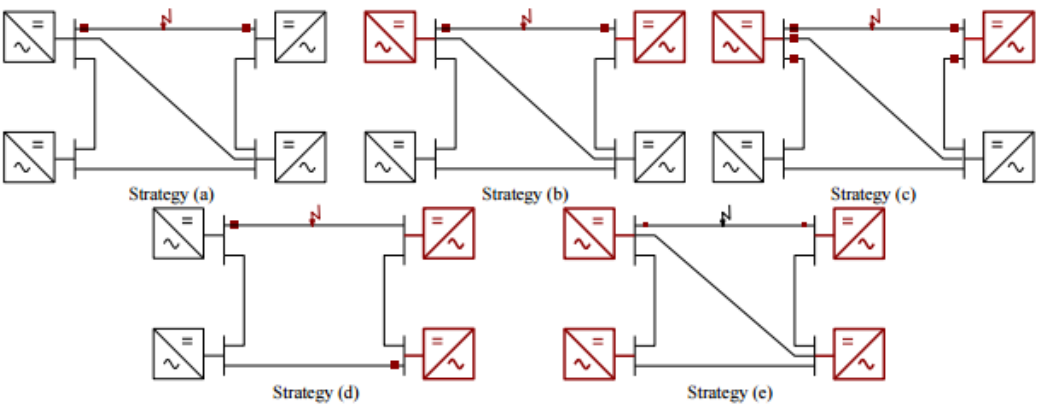

Figure 20 – Classification according to system impact

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These different impact on converter operation (affected converters are indicated by red) can be associated with different impacts on the AC system:

- Strategy (a): no interruption of power flow leading to any problems at the AC side is expected
- Strategy (b): the two converters closest to the converters temporarily lose the power output for a few ms. Thus, for these converters, P_1 limits might apply. If they are connected within a single synchronous zone, the P_1 limit for the synchronous zone applies.
- Strategy (c): the two converters closest to the converters temporarily lose the power output for a few ms to a few hundred of ms. Thus, for these converters, P_1 and P_2 limits might apply. If they are connected within a single synchronous zone, the P_1 limit for the synchronous zone applies.
- Strategy (d): The two converters in the faulted zone cannot transmit power before the fault is cleared. Depending on the fault clearing strategy, this power output might be lost for a few hundred ms to a few s. Therefore, P_2 and P_3 limits might apply. If they are connected within a single synchronous zone or control area, these values should be specified.
- Strategy (e): The power flow within the HVDC grid is zero for a few hundred ms to a few ms, depending on the implementation of the fault clearing strategy. Therefore, P_2 and P_3 limits might apply. If the converters are connected to different synchronous zones or control areas, these values should be specified for each of the connected zones.

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