

POSITION

Subject: Response to the Elia consultation on the general requirements for RFG, DCC, HVDC and storage
Date: 23 April 2018
Contact: Steven Harlem
Phone: 0032 2 500 85 89
Mail: steven.harlem@febeg.be

Introduction

Elia is organizing a consultation on its proposals for general requirements RFG, DCC, HDVC and storage. The consultation is open from the 15th of March, 2018 until the 23rd of April, 2018.

This document is the response of the **Belgian Generators' Associations (BGA): this is an *ad hoc* cooperation of the associations BOP, COGEN, EDORA, FEBEG and ODE.**

BGA welcomes this consultation and wants to thank Elia for creating this opportunity for all stakeholders to submit their comments and suggestions with regard to the proposals for general requirements.

The BGA response to this consultation consists of the following documents:

- a version of the general requirements RFG with track changes and comments;
- a version of the general requirements DCC with track changes and comments;
- a version of the general requirements HVDC with track changes and comments;
- a version of the general requirements storage connections with track changes and comments
- an explanatory note summarizing the main comments and suggestions, i.e. this note.

The five abovementioned documents jointly constitute the BGA response to this consultation. This response is not confidential.

BGA also wants to highlight that it analyzed all general requirements, but that its main focus was on the requirements for generators and storage. The requirements HDVC and DCC were analyzed from a rather high level perspective.

Importance of the categorization of grid users for the interpretation of the general requirements

Categorization of significant grid users A and B

BGA welcomes the decision to set the limit between power generating modules A and B at 1 MW. The shift from the initial proposed limit of 0,25 MW to 1 MW relieves a lot of smaller power generating modules from technical requirements and information exchange obligations that are applicable on category B units. This decision limits the costs for grid users.

In the context of the decision on the limit between type A en B **BGA supports the approach to impose additional technical requirements through the regional grid codes.** BGA does call upon the grid operators:

- not to impose remote control when not necessary;
- to develop transparent and non-discriminatory rules for imposing remote control;
- to investigate if the cost of the remote control cannot be decreased;
- to assess if (a part of) the cost of the remote control cannot be socialized.

Derogations

BGA appreciates that system operators have already – together with the consultation on the proposals for a modified Federal Grid Code and the technical requirements – indicated which derogations they have identified and will apply for. This increases the visibility – although legal certainty is missing – on the requirements that will be applicable on every installation.

Elia has communicated that it will apply for a derogation for power generating modules A and B connected to a voltage level above 110 kV. **The grid users regret that no similar derogation will be submitted for power generating modules type C that are connected to a voltage level above 110 kV: the current regulation will to an unequal treatment of installations type C connected on a voltage level above 110 kV and installations type C connected to a voltage level below 110 kV or via a closed distribution grid.** The voltage condition for the classification of PGMs at industrial sites is discussed at European level. Several countries will propose a class derogation as proposed by ELIA. BGA recommends to closely follow future evolutions and to modify this voltage condition if other countries do so for type C PGMs at industrial sites.

Main comments requirements for generators

Disclaimer

The requirements for generators are far out the most important document for BGA. Unfortunately BGA considers it difficult to come to a final position on the document at this moment because (1) there are no sufficient guarantees for a level playing field, (2) some elements are unclear or information is missing and (3) some requirements are not in line with the NC RfG or are onerous and (4) some requirements are simply unacceptable. Therefore, BGA wants to express its reservations with regard to the requirements for generators.

Level playing field

BGA considers it of utmost importance that a **level playing field is ensured between countries and between types of grid users.**

Therefore, BGA regrets that article 1 of the RfG NC was not repeated in this document: *'This regulation also lays down the obligations for ensuring that system operators make appropriate use of the power-generating facilities' capabilities in a transparent and non-discriminatory manner to provide a level playing field throughout the Union.'*

Many of the non-exhaustive or optional requirements of the Network Codes have been dealt with in other international bodies, whether at ENTSO-E (Implementation Guideline Documents or IGD's) or in normative agencies (IEC, CENELEC, etc). In order to facilitate an efficient European market, both with a level playing field for electricity producers and with harmonized technical rules for equipment manufacturers, **BGA is of the opinion that the Belgian regulation should be as much as possible harmonized with other European countries.** For this reason, BGA would appreciate it if Elia could add to each documents' section the reference to the international norms/guidelines that are being followed **and, when the proposed Belgian regulation deviates from international norms/guidelines, to give a detailed technical justification.**

More severe requirements in Belgium compared to other countries will have a **negative impact on the investment climate in Belgium** which should be avoided at all times.

BGA also wants to point out that, if no agreement is found within Synergrid for some of the requirements, the document should not allow each RSO or each DSO to set its own requirements. Instead, **the concerned requirements should be dealt with in the appropriate legal text (e.g. regional) and be common for all system operators concerned by this legal text.**

Some requirements are unclear or information is missing

To be able to understand certain provisions and hence to take a position on them, several questions need to be answered.

Some examples:

- Article 2.1: Tuning of the PSS may be depending of the load and grid characteristics of a customer of the TSO. How can the grid users access the needed information?
- Article 3.1.1: With regards to the mentioned time windows between 47,5Hz and 49Hz, the questions rises if these are combinable? In other words: if the frequency stays above 47,5Hz, one needs to stay connected for 30 or 60 minutes. For BGA this should be 30 minutes and thus summarized to 47,5Hz – 49 Hz as, otherwise, problems will occur with connected engines and generators (increasing flux leading to heating of the stator).
- Article 3.1.4: This article describes the actions needed at over-frequencies. Why are provisions mentioned for an increase of power in the table page 9?
- Article 3.1.7: This article describes an automatic connection with a gradient of 20% and an automatic reconnection with a gradient of 10%. The operator of a PGM does not know which gradient to apply after a LOM (loss of main). How to apply the correct gradient? BGA assumes that it is 10% in case of network disturbance, but the wording allows different interpretations.
- Article 4.2.2.1: The connection point is operated by the TSO or DSO according to Belgian regulation. Why to mention such requirements as the PGM cannot be responsible for such requirements, e.g. measurements?
- Article 4.3.1: The limitations of the AVR limiter/underexcitation protection (or 32Q) are not indicated on the most P/Q- capacity diagrams of generators. Those protections add additional limitations on the P/Q-capacity of the generators and shall be taken into account for the extended capabilities.
- Article 4.3.2: This article specifies that 'synchronous power-generating module (SPGM) of type B shall be equipped with a permanent automatic excitation control system'. 'Permanent' might refer to permanent magnet excitation system (PMG), which must be ordered separately for the generators. Therefore, this definition needs clarification or grid users need to be informed which kind of excitation sources are allowed (e.g. auxiliary winding, PMG, etc.).
- Article 5.1.2: This article describes the actions needed at under-frequencies. Why are provisions mentioned for a decrease of power in the table page 21?
- Article 5.2.2: This article imposes '*the identification of house load operation must not be based solely on switchgear positions*'. What kind of information has then to be submitted?
- Article 5.3.1: What is the meaning of '*loss of control*'?
- Articles 5.3.1, 5.3.2 and 5.3.3: These articles impose that '*These parameters will be taken in the appendices of the individual connection agreement*'. Do these appendices need to be approved by the regulator? What happens in case of non-agreement?

Some requirements are not in line with the NC RfG or are onerous

Some examples

- General comment: The values of 1 pu are defined only for type D PGMs and values are not mentioned for other types of PGMs. The value of 1 pu has to be mentioned for all types of PGMs.
- Article 3.1.5: This requirement also applies on CHP's whereas article 6.4. of NC RfG makes an exception for CHPs regarding the application of article 13.4. of NC RfG. Elia has to justify the non-respect of the NC RfG.
- Article 4.3.1: This article specifies, for a type B SPGM connected at a DSO grid, the requirements for reactive power at the connection point. The NC RfG allows this for the PGM itself (as defined for a connection at the TSO). The result will be two different requirements that will impose two standards leading to additional costs.
- Article 4.3.2: The content of this article is not consistent with the content of article 17.2.b of NC RfG allowing only a '*constant alternator terminal voltage*'.
- Article 4.3.3: The requirement imposes a tclear of 0.2 sec. The RfG NC allows this in article 14, table 3.1, but only if '*system protection AND secure operation so require*'. A justification is missing in this document. Furthermore, in many countries the same profile is specified for 150 ms, and is considered as a standard value. Hence, without justification, the FRT-profile should be reduced to 150 ms. This comment also applies on article 4.4.1.
- Article 5.5.1: The sentence '*This requirement should be met at the connection point*' is in breach with article 18.2 of NC RfG indicating that the additional reactive power needed for compensation for the HV-line between the connection point and the HV-terminals shall be provided by the responsible owner of that line. The owner in Belgium is the transmission system operator.
- Article 5.5.1: The value of 1.118 pu is in conflict with figure 7 of NC RfG indicating a maximum value of 1.1 pu.
- Article 5.6.2: See the two comments listed above for article 5.5.1 and referring to figure 8 of NC RfG.
- Article 6.1.1: The table imposes voltage ranges from 0.85 pu up to 1.15 pu while the tables 7 and 8 of the NC RfG impose a voltage range for reactive power in the fixed outer envelope from 0.875 pu up to 1.1 pu.
- Article 6.3.1, table 1: See comment regarding tclear = 0.2 sec above.
- Article 6.4.1, table 2: See comment regarding tclear = 0.2 sec above.

Unacceptable requirements

For some provisions additional justification is absolutely necessary. At the moment BGA doesn't understand or support the reasons of these requirements. As a result, these requirements are - at the moment - not acceptable for BGA.

Some examples:

- Article 2: BGA pleads to treat installations of type C but connected ≥ 110 kV not as a type D, but as a type C. This follows the same approach as Elia suggest for type A and B (see above).
- Article 4.3.4 with regard to post fault recovery for Type B SPGM: Elia requires 90% of the pre fault power within 3 seconds. This is only possible in full load. If the GT would run part load the IVG will play part resulting in a slower reaction, driven by low NOx recovery.
- Article 4.4.3: The requirement with regard to injection of current at an overvoltage is not possible.
- Article 5.1.1: If the automatic remote device is out of service, the time to react is 15 min. This is not realistic for a type C PGM.
- The formula on page 24 contains the factor '0.45'. This value is out-of-date as it was an element of the old Belgian legislation.

Main comments requirements DCC

General comment

In the introduction it is stated that the general requirements for DCC are only partially supported by Synergrid. In other words, it is possible that there will be differences between the rules imposed by the TSO and the rules imposed by the DSO's. **Such discriminatory approach should be avoided at all times. Therefore, BGA calls Synergrid to strive for a level playing field and to harmonize by developing common requirements** for demand facilities connected on the TSO as well as on the DSO grid.

Detailed comments

Article 1.1.1:

BGA asks Elia to check the frequency requirements with the producers of end users' appliances to be sure that the requirements are compliant with those technical characteristics of those appliances, e.g. medical equipment.

Article 2:

It is not clear if the requirements for demand facilities with respect to delivery of demand response services are applicable on all demand facilities or only on the ones that effectively supply – on a voluntary basis – demand response services. On top of that, does the demand facility still has to comply with requirements when it stopped offering demand response services?

BGA also assumes that demand response services will be contracted via market based mechanisms, or at least be fairly remunerated.

Finally, it is of utmost importance that the impact of the activation of demand response services on other market parties, e.g. BRP, supplier, ..., is neutralized.

BGA is of the opinion that the abovementioned elements should be clarified and added – at least in footnote – to requirements.

Article 2.2.2 – 2.2.4:

The requirements for voltage ranges, dead band, maximum frequency deviation to respond, ...have to be – of units connected above 110 kVA – subject to market consultation.

Main comments general requirements HVDC

General comment

The Elia proposal for general requirements HVDC leaves most points open for an *ad hoc* solution. Although this approach has the advantage of flexibility, it has also some downsides: (1) potential investors will have difficulties to have a view on the requirements that will be applicable on the installation and (2) it will be difficult to ensure a level playing field between the projects.

Detailed comments

Article 2.2.7.1 and 3.1.6.1:

Both articles are referring to the Synergrid regulations, but the relation with the Synergrid regulations is not clear. Why is there no reference to IEC?

Article 2.4.4:

Germany has already experienced difficulties as a result subsynchronous torsional interactions which has led to problems and costs at the grid users. Therefore, **the transmission system operator should demonstrate that the existing installations as well as new installations will not be impacted by the subharmonic distortions.**

Article 3.2.3.1:

Synergrid has no requirements as regards subharmonic distortions. The requirement related to power quality should therefore be set with consent of the PPM owners.

Main comments general requirements storage connection

General comment

Storage is in its infancy and extra regulation can only slow down its development. Moreover, most power electronics devices are manufactured abroad and follow international standards which are not going to be directly impacted by Belgian regulation. This regulation has thus no added value and can only become a blocking point, slowing down development of storage. This is especially true for type A SPM and non-stationary applications where potential extra costs would be relatively much higher. Given that there is no EU obligation, BGA believes that sufficient time should be taken to develop efficient regulation on storage, with a consistent and general vision taking into account all aspects (technical, market, support, etc) and also lessons learned from the first projects and future EU regulation.

BGA regrets that Elia imposes such strong requirements to storage power modules: (1) the document makes no distinction between storage facilities that provide services to the market and storage facilities that deliver services on site; (2) the proposed requirements are sometimes more severe than the requirements for generators as the storage facilities cannot benefit from the exceptions foreseen in the NC RfG (e.g. derogations, exceptions for emergency batteries, ...) and (3) Elia also proposes really severe requirements for data exchange, remote control and contribution to reactive management.

Detailed comments

General comment

The document often refers to the NC RfG while this NC explicitly states not to be applicable on SPM. To avoid legal issues, BGA recommends to repeat the actual requirements of the NC RfG.

Article 1:

This article introduces the requirements for storage and describes the background. But at the same time, it raises a lot of questions that are not answered. **BGA is of the opinion that the following aspects should be addressed** as well:

- SPM that don't deliver services to the grid (e.g. UPS, peak shaving in industrial context, ...) should be out of scope; only SPM that offer services in the market should be in scope.
- The document doesn't point to the fact that SPM are only capable of limited injection or off-take of energy in time.
- Storage systems is broader than only electric storage systems, e.g. mechanic (flywheel) and chemical (batteries) storage should also be in scope.

- The distinction between Pump Storage Systems (PPS) and other types of storage should be more clarified and detailed as PPS are within scope of the requirements of NC RfG while there are no European requirements for the other types of storage. A better and broader definition of storage seems to be necessary.

Article 2:

It is important to note that the **state of charge can only be expressed taking into account the technical characteristics of the SPM.**

Article 4.1.5:

The document states that an interface should be available to receive the signal to interrupt injection. **It should be clear and also mentioned that Elia is responsible to deliver to signal to the interface. It should also be clarified that Elia can only intervene in the operation of the installation when the market is no longer in status 'normal' or 'alert'.** In the status 'normal' or 'alert' one should rely on the market to find a solution.

Article 4.2 (see also comment 4.1.5)

This requirement is also applicable on home batteries: this means that Elia is also responsible for delivering a signal to these batteries.

Article 4.2 and 5.2.3:

BGA wonders why it is not foreseen to send two signals. At the moment, only one signal will be sent with the message to stop. This implies that also SPM that contribute to the grid – that are injecting – will be stopped.

Article 5.1.1 and 6.1.1:

Why is it necessary for Elia to be able to remotely control the reduction of active power? Why should Elia be able to send a set point for this batteries? BGA is of the opinion that such intervention should not be allowed when the market is in status 'normal' or 'alert'. On top of that, **a market should be created to allow Elia to procure this service or, at least, the service should be properly remunerated** taking into account the energy and missed opportunities.

Article 5.4:

When a battery is embedded in an industrial grid or CDS, **it should be possible to comply with the requirement for reactive power with other assets.** If the battery is not embedded, the following questions rise. How can one demonstrate to be compliant with the requirement? Does Elia want to be able to steer the reactive power? If yes, how and how will this service be remunerated?

Article 5.4:

This article that mentions that SPM should not limit its capabilities to comply with the requirement. **BGA wonders how the costs linked to the delivery of higher capabilities that strictly necessary will be compensated.**

Article 6.1.3:

BGA proposes to include in this article the requirements for frequency sensitivity mode.

Article 6.3:

BGA suggests the alignment of the requirements in 6.3 with the ones in 5.4 taking into account installations on industrial sides. Otherwise the values need to be measured at the HV side of the step-up transformer or at the convertor terminals.

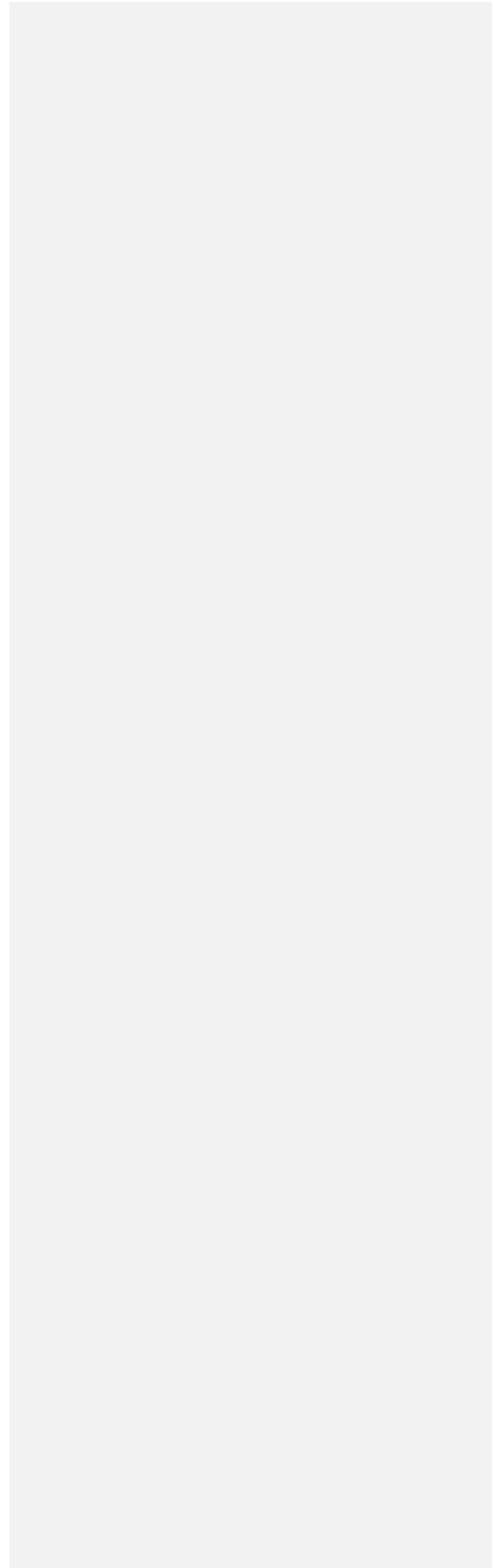
Article 6.3, figure 7:

Maximum voltage should be equal to 1.1 p.u and not 1.18 p.u.



PROPOSAL FOR NC RFG REQUIREMENTS OF GENERAL APPLICATION

Public consultation 15 March – 23 April 2018



Contents

1 Introduction	333
2 Proposal for determination of significance [Art 5]	555
2.1 Conditions for the choice of the maximum capacity thresholds.....	776
3 Type A Requirements	777
3.1.1 Frequency withstand capability [Art. 13-1 (a)]	887
3.1.2 Rate Of Change Of Frequency (ROCOF) withstand capability [Art ... §	887
3.1.1(b)]	887
3.1.3 Loss of Main Protection triggered by rate-of-change-of-..... §	998
frequency-type [Art 13.1(b)]	998
3.1.4 Limited Frequency Sensitive Mode – Over frequency (LFSM-O) [Art.	998
..... §	998
13-2 (a-g)].....	998
3.1.5 Admissible maximum power reduction with falling frequency [Art. 11	1110
13-4]	1110
3.1.6 Logical interface to cease active power injection [Art 13-6]....	1211
3.1.7 Automatic connection [Art 13-7].....	1211
4 Type B Requirements	1312
4.1 Frequency stability and active power management.....	1312
4.1.1 Remote control reduction of active power [Art 14 -2]	1312
4.1.1 Automatic reconnection [Art 14-4 (a-b)].....	1312
4.2 Instrumentation [Art 14-5].....	1312
4.2.1 Structural data: control and electrical protection schemes and	13
settings [Art 14-5 (a + b)].....	1312
4.2.2 Information exchanges [Art 14-5(d)]	1312
4.3 Type B – SPGM Requirements.....	1414
4.3.1 Reactive power capabilities - SPGM [Art 17-2(a)].....	1414
4.3.2 Voltage Control SPGM type B [Art 17-2 (b)]	1515
4.3.3 Fault-ride through for symmetrical and asymmetrical faults for	15
SPGM [Art 14-3].....	1515
4.3.4 Post-fault active power recovery - SPGM [Art 17-3]	1616
4.4 Type B – PPM Requirements.....	1716
4.4.1 Fault-ride through for symmetrical and asymmetrical faults - PPM 17	1716
[Art 14.3].....	1716
4.4.2 Reactive capabilities - PPM [Art 20-2(a)]	1818
4.4.3 Fault Current & dynamic voltage support [Art 20-2 (b and c)].	1919
4.4.4 Post-fault active power recovery [Art 20-3].....	2020
5 Type C Requirements	2120
5.1 Frequency stability & Active Power management.....	2120
5.1.1 Active Power Controllability and Control Range [Art. 15-2 (a-b)]	2120
.....	2120
5.1.2 Limited frequency sensitive mode – under frequency (LFSM-U) [Art.	21
.....	2120
15-2 (c)]	2120
5.1.3 Frequency Sensitive Mode [Art. 15.2.d]	2222
5.1.4 Frequency restoration control [Art 15-2.e].....	2323
5.1.5 Real-time monitoring of FSM [Art 15-2.g]	2323
5.1.6 Automatic disconnection for voltage outside ranges [Art 15-	2323
3].....	2323
5.1.7 Rates of change of active power output [Art 15-6(e)].....	2424
5.2 System restoration [Art 15-5]	2424
5.2.1 Capability to take part in island operation [Art 15.5(b)]	2424
5.2.2 Quick resynchronization capability [Art 15-5(c)]	2424
5.3 Instrumentation, simulation and protection	2424
5.3.1 Loss of angular stability or loss of control [Art 15.6(a)]	2424
5.3.2 Instrumentation [Art 15.6(b)]	2525
5.3.3 Simulation models [Art 15.6(c)]	2525

5.3.4	Devices for system operation and security [Art 15.6(d)]	252524
5.3.5	Earthing of the neutral point at the network side of the step-up transformer [Art 15.6(f)]	252524
5.4	Voltage control mode (for SPGM and PPM) [Art 19-2(a) and Art 21.3(d)]	252524
5.5	Type C SPGM Requirements	262625
5.5.1	Reactive power capability SPGMs [Art 18-2]	262625
5.5.2	Voltage control requirements for SPGM type C	272725
5.6	Type C PPM Requirements	272726
5.6.1	Synthetic inertia for PPM [Art 21-2]	272726
5.6.2	Reactive capabilities - PPM [Art 21-3(a-c)]	272726
5.6.3	Voltage control - PPM [Art 21-3 (d) and (e)]	292927
6	Type D Requirements	292928
6.1	Voltage Control	292928
6.1.1	Voltage withstand capability [Art 16-2(a & b)]	292928
6.1.2	Automatic disconnection for voltage outside ranges [Art 16-2(c)]	29
6.2	Resynchronization [Art 16-4]	303028
6.3	Type D SPGM Requirements	303028
6.3.1	Fault-ride through for symmetrical and asymmetrical faults – SPGM [Art 16-3]	303028
6.3.2	Voltage stability SPGM [Art 19-2]	313129
6.3.3	Technical capabilities to support angular stability under fault conditions for SPGM [Art 19-3]	313130
6.4	Type D - PPM	313130
6.4.1	Fault-ride through for symmetrical and asymmetrical faults – PPM [Art 16-3]	313130
7	Acronyms	323231
8	References	323231
9	Appendix I – Definition FRT profile (extract from Art. 14.3 RfG[1])	343432
10	Appendix II - List of non-exhaustive articles for RfG	343432

1 Introduction

Article 7(4) of the NC RfG [1] states that the relevant system operator or TSO submits a proposal for requirements of general application (or the methodology used to calculate or establish them), for approval by the competent entity, within two years of entry into force of the NC RfG, i.e. 17 May 2018. A similar requirement is included in the two other connection Network Codes, namely in Art. 6(4) of the NC DCC [2] and in Art. 5(4) of the NC HVDC [3].

The aim of this document is to synthesize the technical proposal regarding the Belgian implementation of the non-exhaustive requirements stated in the NC RfG. This document is the final version of the proposal for requirements of general application (hereafter named as 'general requirements'), in accordance with Art. 7(4) of the NC RfG.

The proposal is mainly focusing on requirements set by Elia, as (relevant) TSO or relevant system operator. Since the public DSOs were also largely involved in developing the TSO proposal or in defining their own implementation proposals for PGMs (power generating modules) connected to the distribution system, part of the requirements is also set by the public DSOs, as relevant system operator.

To facilitate the implementation of the NC RfG requirements, Elia and the public DSOs aligned as much as possible to increase the coherency and avoid as much as possible discrimination between a transmission-, or distribution-connected PGM in terms of technical requirements and legal readability. For aspects of the general requirements relevant for CDSOs, Elia has also been interacting with CDSOs.

On 17 May 2018, Elia will submit the general requirements proposals for NC RfG, but also for NC DCC and NC HVDC to the competent authorities together with the (track change) proposal of the amended Federal Grid Code [4] and the formal proposal on maximum capacity thresholds of type B, C and D PGM. Elia will organize beforehand a public consultation for all deliverables in March-April 2018, except for the public consultation on the maximum capacity thresholds B, C and D, that already took place from 19 May till 20 June 2017. This approach is in line with the vision of the Belgian Federal Administration (FOD/SPF Energy) [5].

This document represents the most recent position of Elia after discussions with the stakeholders in each of the relevant topics. During the last months, this document was gradually completed and presented to stakeholders, especially during the Federal Grid Code workshops until all non-exhaustive general requirements were included.

This document should be considered as a technical and not legally binding document, focusing on the clarification of various technical general requirements that will be reflected in various grid codes, contracts, terms and conditions, regulatory documents and/or technical prescriptions.

The document follows the same article order as in the NC RfG: the proposal is organized per technical topic and per PGM category, assuming the thresholds B, C and D as defined in Elia's (and public DSOs') proposal [6]. If not otherwise specified, each higher category has to fulfil the requirement of the lower one. As an example, the LFSM-O is specified for type A, but it is also valid for types B, C and/or D PGMs.

The scope of this document contains especially, but is not limited to, the implementation proposal of the non-exhaustive requirements in the NC RfG. To increase its readability, this document might also contain NC exhaustive requirements, implementation proposals of non-exhaustive requirements of the other connection NC, or other specific national/regional requirements for information purposes only, but certainly does not cover all of them.

With respect to the complete list of non-exhaustive requirements to be proposed as general requirements, Elia is taking as reference the ENTSO-E implementation guidance document (IGD) on 'Parameter of Non-exhaustive requirements' [7] to be defined by the (relevant) TSO and the relevant system operator. This document does not only mention the parameters to be defined per topic, but also which article of each connection NC should be considered as non-exhaustive and who should be the relevant system operator to define an implementation proposal. The TSO, DSOs and CDSOs can be considered as 'relevant system operator', depending on the requirement.

Commented [A1]: General remark: remuneration for delivered services is necessary to provide a level playing field as described by art. 1 of RfG RfG.

Commented [A2R1]: "This regulation also lays down the obligations for ensuring that system operators make appropriate use of the power-generating facilities' capabilities in a transparent and non-discriminatory manner to provide a level playing field throughout the Union."

As a general consideration, the present document proposes minimum requirements. If a PGM has capabilities beyond the minimum required and its utilization has no negative technical and financial impacts on its normal operation, this capability should be available for activation in agreement with the relevant system operator (note: for Elia it will be during connection agreement). As a matter of example, should the PGM have capabilities beyond the minimum Fault Ride Through profile (cf. Art. 14-3), the PGM is expected to not limit its capabilities to comply with the minimum requirement but to use the full capability to support the system stability as stated in its agreement. The actually implemented PGM characteristics and functionalities must be communicated to the relevant system operator and/or transmission system operator.

Commented [A3]: With regards to requirements beyond the minimum threshold: the offering of such capabilities for activation should ideally be part of an ancillary service contract.

2 Proposal for determination of significance [Art 5]

The current proposal for determination of significance has been shared with the stakeholders through the “Public consultation relating to the proposal for maximum capacity thresholds for types B, C and D power-generating modules” running from 19/05/2017 to 20/06/2017 and is available [online](#). The proposed thresholds are the result of several rounds of workshops and discussions with the stakeholders and the authorities. A synthesis of the proposed determination of significance is presented here below.

In line with the NC RfG Art. 5, Elia is proposing the following choice of maximum capacity thresholds for the determination of type:

- Type A ○ 0.

$$8kW \leq P_{MAX}^{Capacity} < 1 MW \text{ and } V_{cp} < 110kV$$

- Type B ○

$$1 MW \leq P_{MAX}^{Capacity} < 25MW \text{ and } V_{cp} < 110kV$$

- Type C

$$25MW \leq P_{MAX}^{Capacity} < 75MW \text{ and } V_{cp} < 110kV$$

- Type D

$$75MW \leq P_{MAX}^{Capacity} \text{ or}$$

$$0.8kW \leq P_{MAX}^{Capacity} \text{ and } V_{cp} \geq 110kV$$

Where $P_{MAX}^{Capacity}$ is the maximum (installed) capacity of the power-generating modules and V_{cp} is the voltage level at the connection point.

The parameters for the determination of significance are graphically illustrated in Figure 1 below.

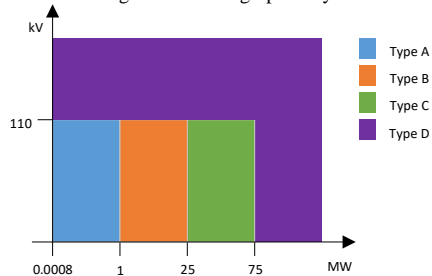


Figure 1 : Graphical representation of the proposed maximum capacity thresholds.

However, Elia is proposing to adapt the requirements for power-generating modules (PGM) with a maximum installed capacity lower than 25MW and with a voltage at the connection point higher or equal to 110kV, in order to reflect the specification of the PGM of the same size with a voltage at the connection point lower or equal to 110kV. The requirements will be adapted via a request for derogation submitted by the relevant system operator or, in this case, the relevant TSO (in line with NC RfG Art. 6.3).

Commented [A4]: We do not agree that assets between 25MW and 75 MW connected above 110 kV are seen as Type D units.

- It will result in discrimination between units connected to the lower voltages (incl. CDS) and units connected to the 110kV grid or beyond, e.g. because the latter units are embedded in an industrial site.

- The FRT requirement of 200ms (CFCT) @ 0.3 p.u. remaining voltage is already very ambitious for most SPGMS. The requirement of type D in which 200 ms @ 0 p.u. should be withstood by the installations, is very demanding and not even always possible. We fear that this would deteriorate the investment climate for units > 25 MW on industrial site, whereas this is now considered as a segment with a lot of potential for investments in renewable generation.

- In some regions, e.g. in ‘Boucle de l’est’, generators are imposed to connect to 110 kV. This leads to more expensive connection costs, but being subject to the requirements of type D is making this involuntary situation even worse.

Commented [A5R4]: For more information we refer to *Response of BGA (Belgian Generators Associations) to the public consultation on maximum capacity thresholds for types B, C and D PGM's*, as organized by Elia

More specifically the following requirements are proposed:

- Type D PGM having a $0.8kW \leq P_{MAX}^{Capacity} < 1 MW$ will follow the same requirements as type A PGM
- Type D PGM having $1 MW \leq P_{MAX}^{Capacity} < 25MW$ will follow the same requirements as type B PGM.

A graphical representation of the expected resulting requirements is presented in Figure 2 below.

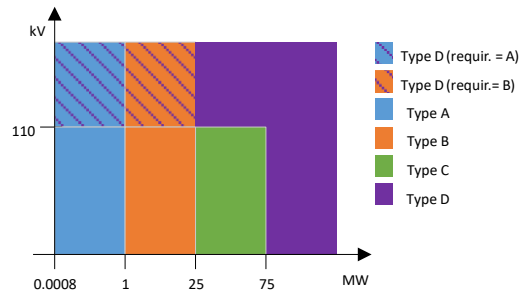


Figure 2 : Graphical representation of the requirements to be followed by PGM depending on the proposed maximum capacity thresholds considering the results of the intended derogation process.

It must be noted that the Power Park Modules (PPM), for which the connection point is located offshore should follow the same prescriptions as type D PPM units except if specifically defined in the present document.

2.1 Conditions for the choice of the maximum capacity thresholds

For type C Synchronous Power Generating Modules (SPGM), stricter requirements than foreseen by the NC RfG for which regards voltage regulations will be necessary, these requirements are already included in the FTR for units of the same type and size (cfr Art. 72 in [4]).

Elia requests Automatic Voltage Regulation (AVR), Over Excitation Limiter (OEL), Under Excitation Limiter (UEL) and Power System Stabilizer (PSS) functions. The activation and tuning of the PSS function will be required depending on the connection point, size and the characteristic of the SPGM.

This approach is in line with the Implementation Guidance Document, proposed and submitted by ENTSO-e, for national implementation of the network codes on grid connection (IGD) on “Parameters of Non-exhaustive requirements: it recommends a site specific implementation of the requirement Art. 19(2)b.(v) through individual connection contract.

Closed Distribution Systems (CDS) requirements will be aligned, to the greatest possible extent, to the ones of Demand Facilities and DSO.

Commented [A6]: Tuning of the PSS may be depending of the load and grid characteristics of a customer of the TSO. How can we access the needed information?

3 Type A Requirements

In general all frequency related parameters are being coordinated between TSOs in the CE synchronous area to guarantee fair contribution among all control areas power generation units and overall resilience and stability of the system. The current requirements are based on the Implementation Guideline Documents (IGD) recently submitted to public consultation in ENTSO-e website (closed 21 Dec 2017)¹.

¹ https://consultations.entsoe.eu/system-development/entso-e-connection-codes-implementationguidance-d-4/consult_view/

3.1.1 Frequency withstand capability [Art. 13-1 (a)]

Proposed frequency range and minimum time period are as following:

Frequency Range	Duration
47,5 Hz – 48,5 Hz	30 minutes
48,5 Hz – 49,0 Hz	30 minutes
49,0 Hz – 51,0 Hz	Unlimited
51,0 Hz – 51,5 Hz	30 minutes

Note: For PGMs connected to distribution grids, the protection settings should not be conflicting with this frequency withstand capability unless in case of local event detection (and not an overall power system event).

Moreover, in application to the paragraphs 13-1 (a)(ii) and (a)(iii), duration of operation in the frequency range from 51,5 Hz to 52,5 Hz shall be dealt with as follows:

- If the TSO (Elia) is the relevant system operator:
 - For units of type B, C and D this shall be agreed between the RSO (Elia) and the generating facility owner in the connection agreement taking into consideration the PGM's possible technical capability.
 - For units of type A, the power generating facility owner shall communicate their technical duration capability to the RSO and put it at disposal of the RSO.
- If the DSO is the relevant system operator:
 - For units of type A and B the RSO shall be informed of the technical duration capability which has to be put at disposal of the RSO. This information can be provided during the type compliance assessment (homologation).
 - For units of type C this shall be agreed between the RSO (DSO), in coordination with the relevant TSO, and the generating facility owner in the connection agreement taking into consideration the PGM's possible technical capability.

Commented [A7]: Is it possible to combine these time windows? In other words if the frequency stays above 47,5Hz does one needs to stay connected for 30 or 60 minutes. For us this should be 30minutes and thus summarized to 47,5Hz – 49 Hz. As problems will occur with connected engines and generators (increasing flux leading to heating of the stator).

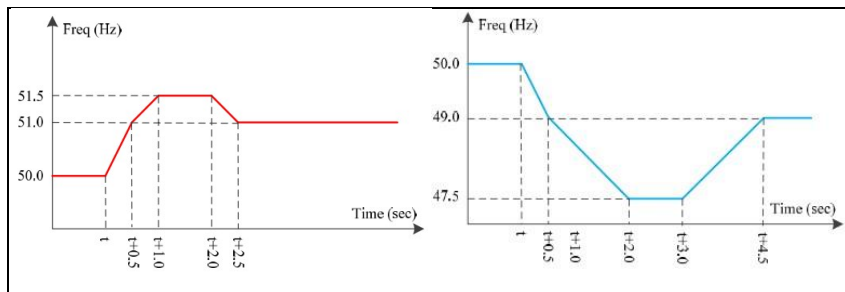
Commented [A8]: How can frequency be local?

Commented [A9]: Only if the PGM is capable.

3.1.2 Rate Of Change Of Frequency (ROCOF) withstand capability [Art 13.1(b)]

The proposed RoCoF withstand capability is defined considering frequency against time profile as depicted in the Figure 3 with explicit measurement technique taking into consideration 2 Hz/s for a duration of 500 ms. For PGM connected to Transmission Network and relying on Loss Of Main (LOM) detection based on RoCoF measurement, the protection settings should not be conflicting with RoCoF withstanding capabilities requirements unless in case of local event detection (and not an overall power system event).

Commented [A10]: Given the stability of the continental grid, it's unlikely that the requirements for ROCOF in Belgium are higher than in a small country like Ireland. Taking in account the consistency of the requirements, they should be adapted to the ones applied in Ireland, i.e. 1 Hz/s/



Over-frequency profile Under-frequency profile
Figure 3 Proposed frequency against time withstanding capabilities

3.1.3 Loss ~~Loss~~ of Main Protection triggered by rate-of-change-of-frequency-type [Art 13.1(b)]

For all PGM a LOM based on RoCoF may be used in coordination with the TSO.

For PGM connected to Transmission Network and relying on LOM detection based on RoCoF measurement, the threshold should be higher than 2 Hz/s for a duration of 500 ms, note that other alternative LOM detection settings should not conflict with frequency withstand capabilities requirements unless in case of local event detection (and not an overall power system event).

For PGMs connected to distribution networks, a Loss of Mains protection based on a ROCOF measurement may be prescribed by the DSO. In line with Art 13.1(b) the public DSOs in coordination with the TSO actually prescribes a default setting of 1Hz/s. In such cases, the interface protection disconnects the PGM before the full withstanding capability is used. Nevertheless, the public DSOs investigate new protection strategies in order to achieve a better coordination.

Commented [A11]: LOM is a protection of the generator in case of unwanted islanding. If the island load is near the island production the rate of the threshold of 2Hz/s shall be too high to detect the islanding.
Also what about the responsibility?

3.1.4 Limited Frequency Sensitive Mode – Over frequency (LFSM-O) [Art. 13-2 (a-g)]

Definition of the non-exhaustive requirements related to LFSM-O function are coordinated between TSOs in the CE synchronous area. Due to the system-wide effect of frequency-related issues, a harmonised setting of these parameters within a synchronous area is desirable. Otherwise adverse impacts can occur, which may aggravate the emergency situations subsequent to the LFSM-O activation. Automatic disconnection and reconnection as referred in 13-2 (b) are not allowed by default.

Taking into consideration the system transient behaviour and the need for an adequate frequency response reaction, the proposal addresses as well the response performance while taking into consideration different PGM technologies.

The PGM response takes into consideration the following aspects as per the Figure 4::

- The dead time (T_d) covers the time from the frequency change event until the beginning of the response;
- The step response time (T_{sr}) covers the time from the frequency change event until the instant until the response reaches the tolerance range for the first time;
- The Settling time (T_s) covers the time from the frequency change event until the instant, from where on the corresponding response remains within the tolerance band of the set value.

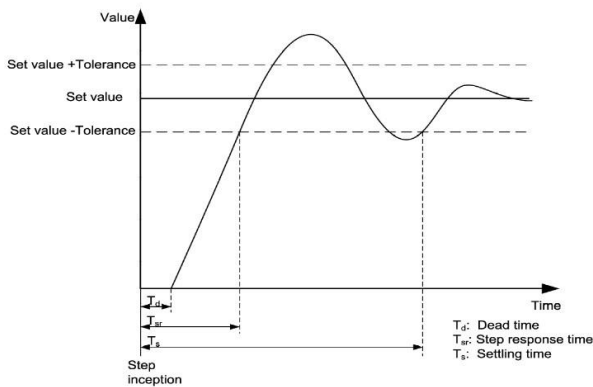


Figure 4: Definition of the PGM response parameters

The below requirements are common for all PGM:

- The droop setting is 5 % and selectable within the range 2% and 12%;
- Frequency activation threshold 50.2 Hz;
- Dead time: by default as fast as technically possible (no intentional delay), specific provisions could be applicable in agreement with the TSO;
- Once the minimum regulating level is reached, the operation mode shall be continued at the same level (no further decrease for further frequency increase).

NC RfG allows two options for defining Pref for power park modules: either Pmax or the actual active power output at the moment the LFSM threshold is reached. In order to achieve an equitable active power response to a high or low frequency event (regardless of the number of power generating modules in operation) the reference active power Pref is therefore assigned based on the expected capacity operation:

- Pref is by default the actual active (at the moment of activation) for PPM.
- Pref can be alternatively defined as Pmax for PPM expected to operate mostly at or near maximum capacity (example for offshore wind farms connected to Transmission Network);

For SPGM:

Parameters (SPGM)	For power increase	For power decrease
Step response time	≤ 5 minutes for an increase of active power of 20 % Pmax (a slow reaction is not applicable in the case of an increase shortly –few second- following a decrease phase)	≤ 8 seconds for a decrease of active power of 45% Pmax
Settling time	≤ 6 minutes for an increase of active power (a slow reaction is not applicable in the case of an increase shortly –few second- following a decrease phase)	≤ 30 seconds for a decrease of active power

Commented [A12]: We do not understand an increase of power at overfrequency

For PPM:

Parameters (PPM)	For power increase	For power decrease
Step response time	<i>For wind generation:</i> ≤ 5 seconds for an increase of active power of 20 % Pmax <i>For the rest:</i>	≤ 2 seconds for a decrease of active power of 50 % Pmax

Commented [A13]: We do not understand an increase of power at underfrequency

Commented [A14]: This should be '≤ 5 seconds for an increase of active power of 20 % Pmax if the current active power is above 50% of maximum power. At operating points below 50% of maximum power a slower reaction may apply' (see https://docstore.entsoe.eu/Documents/Network%20codes%20documents/NC%20RfG/IGD_LFSM-O-U_final.pdf)

	≤ 10 seconds for an increase of active power of 50 % P _{max}	
Settling time	≤ 30 seconds for an increase of active power	≤ 20 seconds for a decrease of active power

3.1.5 Admissible maximum power reduction with falling frequency [Art. 13-4]

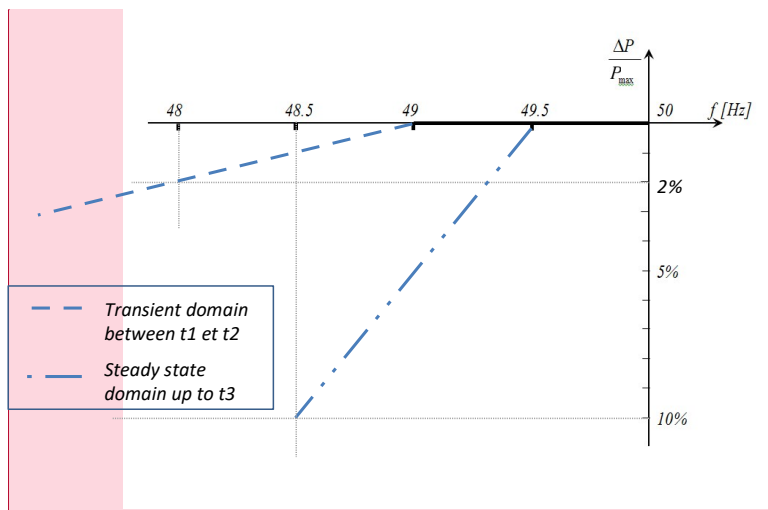


Figure 5 Maximum admissible active power reduction from maximum output for transient and steady state domains

In order to take into consideration system needs and technology limitations, two profiles are covering separately transient domain and steady state domain. In case no technical limitation² to maintain active power are existing, active power reduction is not acceptable. Table 1 covers the requirement during the transient period where the PGM are expected to respect the limit of 2 % active power reduction per Hz from maximum output for a duration up to 30 seconds this would allow other frequency control means to act. During the steady state period, the PGM are allowed if needed to reduce the active power from maximum power output respecting the limit of 10% / Hz.

Table 1 Maximum admissible active power reduction from maximum output requirements

	Parameter	Requirement
Transient domain	Frequency threshold	49 Hz
	Slope	2 % / Hz
	t 1	≤ 2 seconds
	t 2	30 seconds
Steady state domain	Frequency threshold	49.5 Hz
	Slope	10 % / Hz
	t 3	30 minutes

The standard applicable ambient conditions are defined as following:

² Typically PPM do not have inherent limitations resulting in active power reduction from maximum output

Commented [A15]: Not for CHP of type A,B or C according to RfG art 6.4 (embedded generation)

Commented [A16]: According to IGD on P at low f : Furthermore, the verification of compliance might be complex and shall be agreed with the power generating facility owner case by case. This idea is missing.

Commented [A17]: The maximum admissible active power reduction from maximum output in the transient domain is set at 2 % per Hz. This is a really challenging requirement for SPGM and we recommend to increase this value to 10 % per Hz.

Commented [A18]: The proposed standard ambient conditions have a negative impact on the physical capabilities of gas turbines. The reference temperature should be adapted to 0°C. EUTurbines has already addressed this point during the 3rd ENTSO-E workshop on frequency requirements.

-
- Temperature: 25 °C
 - Altitude between 400 m and 500 m
 - Humidity: between 15 and 20 g H₂O/Kg

3.1.6 Logical interface to cease active power injection [Art 13-6]

The right to request additional equipment to achieve remote control of the logical interface will be asserted by the relevant system operator in due time.

Commented [A19]: Who will bring this signal at the site? More details are mandatory

3.1.7 Automatic connection [Art 13-7]

Automatic connection is allowed for all Units of Type A and for units of Type B for which the DSO is the RSO providing the following conditions are satisfied:

1. Frequency to be within 49.9 Hz and 50.1 Hz; and
2. Voltage to be within 0.85 Un and 1.10 Un; and
3. Minimum observation time where the above conditions are satisfied of 60 seconds

Commented [A20]: What is the difference between automatic connection and automatic reconnection? How can a generator type A see the difference.

Commented [A21]: Too small for reconnection in a restoration status of the system given the waiting time of 60 sec.

Following connection adjustable limitation of the gradient of active power increase $\leq 20\%$ of Pmax/minutes is applicable to be fixed as per operational requirement.

When automatically reconnecting following a network disturbance, the maximum admissible gradient in active power output is 10% of Pmax/min.

For other types (Type B connected to transmission system, Type C), automatic connection is subject to individual authorization to be fixed in their individual connection contracts.

Commented [A22]: How to make the distinction with the previous value of 20%. In practice this will be the same value.

4 Type B Requirements

In addition to the requirements for type A, the following is requested.

4.1 Frequency stability and active power management

4.1.1 Remote control reduction of active power [Art 14 -2]

The right to request additional equipment to allow active power to be remotely operated will be asserted by the relevant system operator in due time.

Commented [A23]: By whom? How at E&R when internet is down?

4.1.1 Automatic reconnection [Art 14-4 (a-b)]

As referred in 14-4 (a) the conditions under which the PGM is capable of reconnecting are defined as following:

1. Frequency within 49.9 Hz and 50.1 Hz; and
2. Voltage within $0.90 U_n$ and $1.10 U_n$; and
3. Minimum observation time where the above conditions are satisfied of 60 seconds
4. When reconnecting after a disconnection caused by a network disturbance, a maximum ramping of 10 % Pmax per minute is allowed.

For PGM units of Types B, C and D for which the TSO is the RSO, installation and operation of automatic reconnection are prohibited and subject to authorization in their individual connection contracts on a case by case level. For PGMs of Type B for which the DSO is the RSO, the automatic reconnection is allowed as per the defined conditions.

Commented [A24]: RfG allows for type B and C an automatic reconnection under conditions defined by TSO. Conflict with RfG?

Commented [A25]: TSO commits in general to mobilize all his possible means to reconnect a generator to the grid as soon as technically possible.

How can this be verified by the grid user?

4.2 Instrumentation [Art 14-5]

4.2.1 Structural data: control and electrical protection schemes and settings [Art 14-5 (a + b)]

This specification is a site specific one: it is to be agreed during the connection process with the relevant system operator (he might be the (C)DSO or [Eli&TSO](#)) on a case by case level and fixed in the individual connection contract.

4.2.2 Information exchanges [Art 14-5(d)]

4.2.2.1 Real-time measurements

Requirements :

PGM Type B connected to TSO and DSO

- position of the circuit breakers at the connection point (or another point of interaction agreed with the TSO/DSO);
- active and reactive power at the connection point (or another point of interaction agreed with the TSO/DSO); and
- net active and reactive power of power generating facility in the case of power generating facility with consumption other than auxiliary consumption.

In case of technical infeasibility to communicate this information, gross active and reactive power of power generating facility could be accepted but it has to be agreed during the connection process with the relevant system operator (it might be the (C)DSO or TSO) on a case by case level and fixed in the individual connection contract.

Commented [A26]: General: The measurement points, the metering points must be in line with the billing of the ancillary products and also the obligation points of the capabilities requirements of the PGM.

Commented [A27]: Real-time measurements should not be asked from PGM if they are not used in the TSO/DSO's SCADA. One should avoid duplication of communication lines and IT systems to send twice the same (or similar) information: it should be clarified when data is acquired by TSO/DSO or sent by grid user, but not both at the same time.

Commented [A28]: The connection point belongs to TSO/DSO. The PGM cannot be responsible for those measurements. Why to mention this?

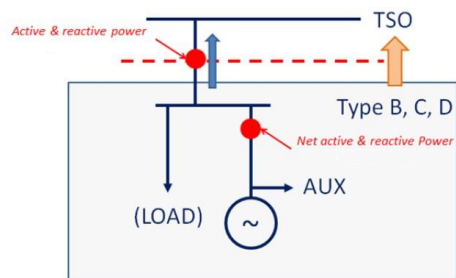


Figure 6: Clarification of the concept of net and gross measurement.

Commented [A29]: This drawing is too simplistic. What about step-up transformers?

Commented [A30]: Precise format needed. Proposal for a standard : 4 -20mA
Will it be possible for a third party to install such a meter?

Real-time measurement is defined as a measurement (representation of the current state of a facility) that is refreshed at a rate higher (faster frequency of refreshing) than one minute.

For data related to automatic load-frequency control processes & flexible generation, it shall not be longer than 10 s.

For other purposes, it shall be as fast as possible and, in any case, not longer than one minute.

Note that other real-time measurements could be required by the relevant system operator(s) depending on the location of the PGM and type of prime mover.

During the connection procedure of the unit, the exact list of signals to exchange, the communication protocols and infrastructure requirements are communicated by the relevant system operator.

Commented [A31]: This is too broad. Criteria's are required (technical/financial/...)

Commented [A32]: No, one unique format is desired.

4.3 Type B – SPGM Requirements

4.3.1 Reactive power capabilities - SPGM [Art 17-2(a)]

For TSO connected units, the required reactive capabilities should be met at the HV side of the step up transformer if existing; otherwise it should be met at the alternator terminals.

For public DSOs, the required reactive capabilities should be met at the Point of Connection with the public network.

For SPGMs of type B, the requirement for the reactive power provision capability is determined by the Q/P profile represented in Figure 7 where the limitations are based on nominal current at high active power output and by a reactive power (Q) limited to -33% and +33% of P_D , where P_D is the maximum active power that can be produced in case of the maximum requested reactive power output (hence equal to $0.95 \cdot S_{nom}$).

With respect to voltages different from 1pu, the required $U/U_c-Q/P_D$ profile is represented in Figure 8.

Note that the effective resulting available capability of the SPGM at the connection point (that might be different than the one at the SPGM terminals) should be communicated, demonstrated and put at disposal of the relevant system operator during the connection procedure.

The owner of the SPGM is not allowed to refuse the use of the reactive capability without a technical justification. The unit is therefore expected to not limit its capabilities to comply with the minimum requirement but to use the full capability to support the system stability as stated in its agreement.

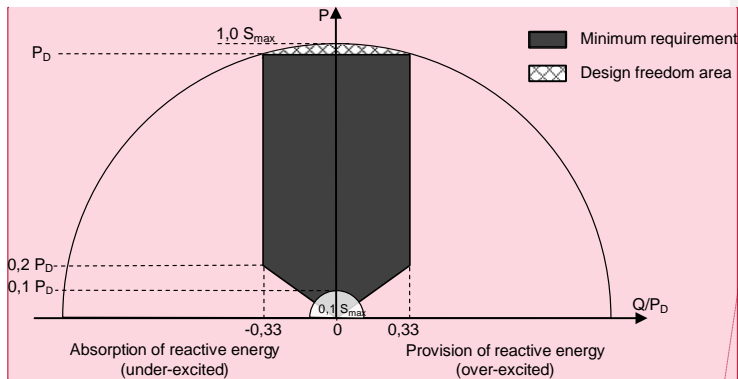


Figure 7: Capability curve for SPGM type B

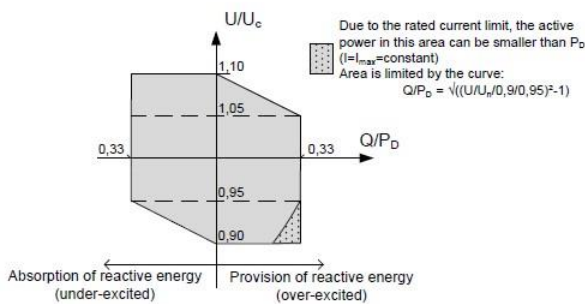


Figure 8: U/U_c-Q/P_D profile for type B SPGM in order to visualize reactive power requirements for voltages different from 1pu.

4.3.2 Voltage Control SPGM type B [Art 17-2 (b)]

With regards to the voltage control system, a synchronous power-generating module (SPGM) of type B shall be equipped with a permanent automatic excitation control system that can provide constant alternator terminal voltage at a remotely selectable setpoint without instability over the entire operating range of the synchronous power-generating module. This means that this SPGM shall be capable to control voltage with 2 control modi:

- Qfix: maintain a constant reactive power within the P/Q capabilities of Figure 7.
- Q(U): maintain a constant alternator voltage within the P/Q capabilities of Figure 7.
- For all those control modes the setpoint should be remotely selectable.

Note: Other reactive power control modi that are needed for local distribution management may be requested by the DSO.

4.3.3 Fault-ride through for symmetrical and asymmetrical faults for SPGM [Art 14-3]

This requirement should be met at the connection point .

The SPGM should be able to support the network during fast transient voltages and network shortcircuits for which the profile of the voltage versus time is referred as Fault-Ride-Through (FRT). SPGM shall fulfil the requirements in the figure below, where the SPGM shall remain connected to the grid as long as the voltage of the phase having the lower voltage is above the profile.

It is recommended however to remain connected as long as the technical capability of the PGM would allow. The same profile applies for asymmetrical faults.

Commented [A33]: Figure is drafted for terminals of alternator. Not at the HV side of the step up transformer.

Commented [A34]: The limitations of the AVR limiter/underexcitation protection (or Q32) are not indicated on the most P/Q-capacity diagrams of generators. Those protections add additional limitations on the P/Q capacity of the generation and shall be taken into account for the extended capabilities.

Commented [A35]: Value of 1 pu is for each voltage level?

Commented [A36]: Which voltage to control? Generator or step-up HV? AVR (=automatic voltage controller, incorporated in generator control system) either controls generator voltage at fixed setpoint (adjustable), or generator Q setpoint. always within generator capability limitations. Q is not allowed by RfG.

Commented [A37]: This notion needs to be further clarified. 'Permanent' might refer to permanent magnet excitation system (PMG) which must be ordered separately for the generators. Therefore, this definition needs clarification or we need to know which kind of excitation sources are allowed, e.g. auxiliary winding, PMG, etc.

Commented [A38]: Should be measured at the alternator, not the HV side of the transfo.

The proposed Fault-Ride-Through parameters are presented in the figure below.
 A voltage $U=1$ pu represents the rated voltage (phase-to-phase) at the connection point.

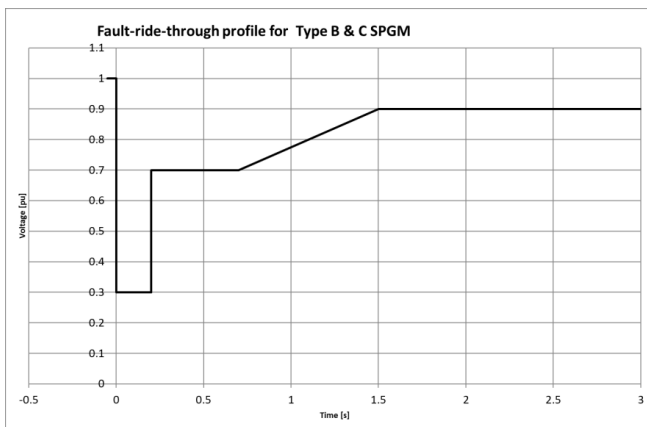


Figure 9: FRT requirement for SPGM type B and C

Tabel 2 : Parameters of the FRT requirements for SPGM of type B and C.

Voltage parameters [pu]	Time parameters [seconds]
$U_{ret} = 0.3$	$t_{clear} = 0.2$
$U_{clear} = 0.7$	$t_{rec1} = t_{clear}$
$U_{rec1} = 0.7$	$t_{rec2} = 0.7$
$U_{rec2} = 0.9$	$t_{rec3} = 1.5$

Commented [A39]: General requirement in the RfG is 0.14 - 0.15 in Table 3.1. Exception is 0.14-0.25 but it has to be justified by TSO. So justification from ELIA is mandatory demonstrating the necessity of this requirement for the secure and safe operation of the grid.

The parameters considered for Fault-Ride-Through capability calculations (e.g. pre and post fault short circuit capacity, pre-fault operating point of the SPGM...) are communicated by the TSO on request of the power-generating facility owner during the connection process.

Commented [A40]: The pre- and post-conditions of the FRT capabilities should be known before the generator is ordered. Therefore, we recommend to publish those conditions.

According to Art 14 3. (a) (vii), the relevant system operator can specify narrower settings for minimum voltage protection.

4.3.4 Post-fault active power recovery - SPGM [Art 17-3]

It is required that SPGM of Type B are able to provide post-fault active power recovery.

For distribution connected SPGMs of type B for which the public DSO is the relevant system operator, the proposed default post fault active power recovery requirement is 90% of pre-fault power within 3 seconds. Another site specific specification is to be agreed during the connection process with the DSO in coordination with the TSO.

Commented [A41]: This is only possible in full load. If the GT would run part load the IVG will play part resulting in a slower reaction, when returning to low Nox mode.

For all other SPGMs, the values of the magnitude and time for the active power recovery will be a site specific specification: it is to be agreed during the connection process with the TSO on a case by case level and fixed in the individual connection contract.

4.4 Type B – PPM Requirements

4.4.1 Fault-ride through for symmetrical and asymmetrical faults - PPM [Art 14.3]

This requirement should be met at the connection point.

The PPM unit should be able to support the network during fast transient voltages and network shortcircuits for which the profile of the voltage versus time is referred as Fault-Ride-Through (FRT). PPM shall fulfil the requirements in Figure 10 (the evolution of the minimum voltage at the Connection Point), where the PPM shall remain connected to the grid as long as the voltage of the phase having the lower voltage is above the profile of Figure 1010. It is recommended however to remain connected as long as the technical capability of the PPM would allow it. The same profile applies for asymmetrical faults.

The proposed fault-ride-through parameters are presented in Table 3.

A voltage $U=1$ pu represents the rated voltage (phase-to-phase) at the connection point.

Commented [A42]: Value of 1 pu is missing.

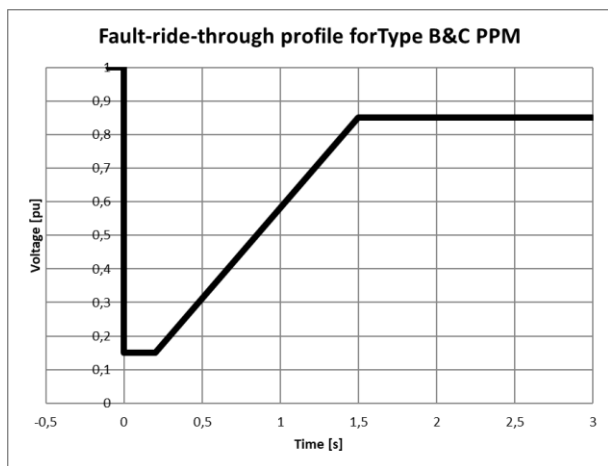


Figure 10: FRT requirement for PPM type B and C

Table 3 : Parameters of the FRT requirements for PPM of type B and C.

Voltage parameters [pu]	Time parameters [seconds]
U _{ret} =U _{clear} =U _{ret1} = 0.15	t _{clear} =t _{rec1} =t _{rec2} = 0.2
U _{rec2} = 0.85	t _{rec3} =1.5

Commented [A43]: See above as for SPGMs

According to Art 14 3. (a) (vii), the relevant system operator can specify narrower settings for minimum voltage protection..

4.4.2 Reactive capabilities - PPM [Art 20-2(a)]

The required reactive capabilities should be met at the HV side of the step up transformer if existing; otherwise they should be met at the inverter terminals.

For PPMs of type B, the requirement for the reactive power provision capability is determined by the Q-P profile represented in Figure 11 where the limitations are based on nominal current at high active power output and by a power factor (cos(phi)) defined by the 2 points at Q= -33% and +33% of P_D, where P_D is the maximum active power that can be produced in case of the maximum requested reactive power output (hence equal to 0.95*S_{nom}).

With respect to voltages different from 1pu, the required U/U_c-Q/P_D profile is represented in Figure 12.

Note that the effective resulting available capability of the PPM at the connection point (that can be different than the one at the PPM terminal) should be communicated, demonstrated and put at disposal of the relevant system operator during the connection procedure.

The owner of the PPM is not allowed to refuse the use of the reactive capability without a technical justification. The unit is therefore expected to not limit its capabilities to comply with the minimum requirement but to use the full capability to support the system stability as stated in its agreement.

Commented [A44]: Other than technical reasons need to be accepted as well.

In case the PPM unit has already the capability of voltage regulation, it should not refuse the relevant system operator to make use of this capability of voltage regulation. In this case, the settings of the controllers should be agreed with the relevant system operator.

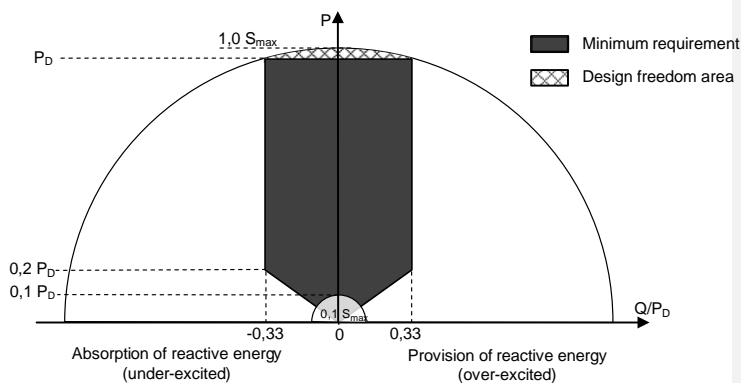


Figure 11: Capability curve for PPM type B

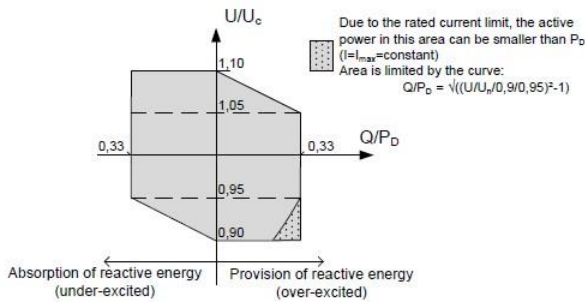


Figure 12: U/Uc-Q/P0 profile for type B PPM in order to visualize reactive power requirements for voltages different from 1pu .

Note: The control modi that are needed for local distribution management may be requested by the DSO.

4.4.3 Fault Current & dynamic voltage support [Art 20-2 (b and c)]

The PPM unit shall be able to inject/absorb additional reactive current compared to the pre-fault state during low and high voltage conditions up to the maximum of its capability.

The additional injected/absorbed reactive current shall be function of the positive sequence voltage at the connection point.

The requested additional reactive current characteristic injection is illustrated in Figure 13.

For voltages within the deadband $[\Delta V_-^{act}, \Delta V_+^{act}]$, the PPM unit should follow the normal voltage control mode.

The injection or absorption of additional reactive current shall be delivered by the PPM with a minimal delay from the detection of the over/undervoltage, t_{iq}^{act} . The functionality should remain active for a minimum time of t_{iq}^{on} and can be deactivated if the voltage returns and remains within $[\Delta V_-^{act}, \Delta V_+^{act}]$ for a time longer than t_{iq}^{off} .

The parameters of this functionality lying within the normal operational range of the installation as well as the delays of activation, dead band and duration of the activation are to be agreed during the connection process on a case by case level and fixed in the individual connection contract with the relevant system operator (it might be the CDSO or Elia) in coordination with the relevant TSO. These parameters are thus a site specific requirements.

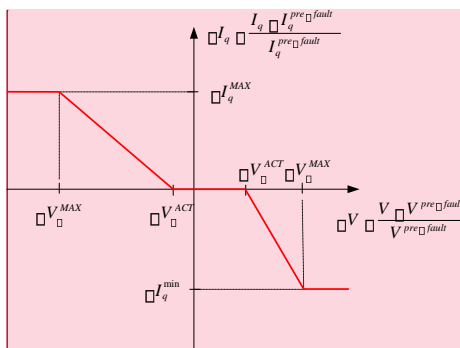


Figure 13: Injection of additional reactive current

For the reliable detection of asymmetric faults, the PPM unit shall contribute to the fault with positive, negative and zero-sequence current. The short-circuit contribution is to be agreed during the connection

Commented [A45]: With this sentence a lot of different control modi are possibly. Requirements should be reduced to the European common control modi which are defined in the Cenelec EN 50549-2.

Commented [A46]:

Commented [A47]: What is the link between over voltage and fault current?

Commented [A48]: This requirement (different k-factor with regard to overvoltage and undervoltage) is rather unusual compared to international standards. For the definition of the dynamic grid support please refer to Cenelec 50459-2 also for connections of Type C and Type D. If studies prove that different k-factors are needed for a secure network operation, manufacturers should be given more time (at least two years) to implement this function. This is possible because this function is not an exhaustive requirement from the RfG.

The use of a deadband should be possible for Wind turbines that are not able to behave like conventional power plants with a continuous voltage control. The standard requirement should be a voltage control without deadband with a continuous voltage control.

Commented [A49]: RSO or TSO? Quid DSO?

Commented [A50]: Information from Vestas V126 mentions only voltage drops, no increases.

Commented [A51R50]: 9.6.1 Symmetrical Reactive Current Contribution

During symmetrical voltage dips, the wind farm will inject reactive current to support the grid voltage. The reactive current injected is a function of the measured grid voltage.

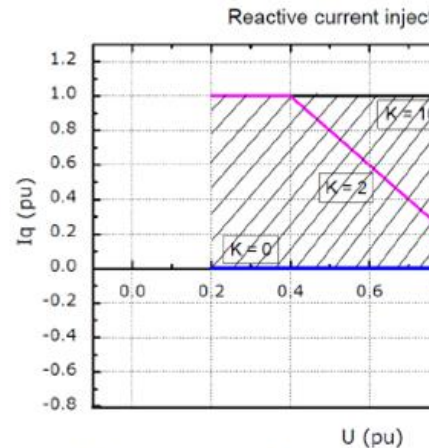


Figure 9-6: Reactive current injection

Commented [A52]: We do not inject a zero sequence. I do not see how this is physically possible through a transformer! In Germany the grid codes even forbids to inject a zero sequence.
Proposal: delete the word "zero-sequence."

Commented [A53]: What are the criteria?

process on a case by case level and fixed in the individual connection contract with the relevant system operator (it might be the CDSO or Elia) in coordination with the relevant TSO. This parameter is thus a site specific requirement.

Commented [A54]: RSO or TSO? Quid DSO?

For Type B generating units connected to distribution networks, the DSO intends to refer to the requirement in the future European standard EN50549-2.

4.4.4 Post-fault active power recovery [Art 20-3]

For PPMs connected to TSO, the parameters of this functionality and its activation should be agreed during the connection process with the relevant TSO on a case by case approach and fixed in the individual connection contract. These parameters are thus a site specific requirement.

For distribution connected PPMs of type B for which the public DSO is the relevant system operator, the proposed default post fault active power recovery requirement is 90% of pre-fault power within 1 seconds. Another site specific specification is to be agreed during the connection process with the DSO in coordination with the TSO.

5 Type C Requirements

In addition to the specifications for type B, the following is requested.

Commented [A55]: Change to "in addition to relevant requirements for..." Some requirements are not relevant for C or even contradictory

5.1 Frequency stability & Active Power management

5.1.1 Active Power Controllability and Control Range [Art. 15-2 (ab)]

The relevant TSO shall establish the period within which the adjusted active power set point must be reached. The relevant TSO shall specify a tolerance (subject to the availability of the prime mover resource) applying to the new setpoint and the time within which it must be reached as shown in the figure below.

The minimum period to reach the active power setpoint would be defined in the connection contract as per the technical ramping capabilities. Therefore, dependent on the technology, it is agreed during the connection process on a case by case level and fixed in the individual connection contract with the relevant system operator. These parameters are thus a site specific requirement.

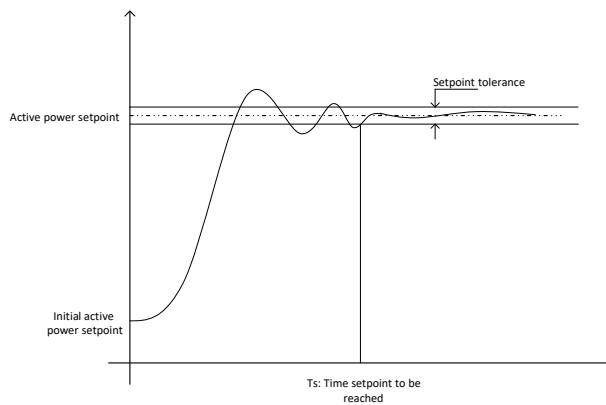


Figure 14 : Tolerance and time duration for application of new set point of active power

With respect to local measures where the automatic remote device is out of service, the minimum time for the setpoint to be reached is equal to 15 minutes for a tolerance of 10% of the active power setpoint.

Commented [A56]: If remote control is out of service a time of 15 minutes is impossible for unmanned PGMs.

Commented [A57R56]: RfG demands the regulators' approval for determining these 15 minutes.

5.1.2 Limited frequency sensitive mode – under frequency (LFSM-U) [Art. 15-2 (c)]

Similarly to the LFSM-O requirements, in order to take into consideration the system transient behaviour and the need for an adequate frequency response reaction, the proposal addresses as well the response performance while taking into consideration different PGM technologies.

Commented [A58]: Missing condition according to RfG Art.15.2.c.ii (ambient temperatures;availability of primary energy sources)

The below requirements are common for all PGM:

- The droop setting is 5 % and selectable within the range 2% and 12%;
- Frequency activation threshold 49.8 Hz;
- Dead time: as fast as technically possible, no intentional delay is foreseen.

NC RfG allows for two options for defining Pref for power park modules: either Pmax or the actual active power output at the moment the LFSM threshold is reached. In order to achieve an equitable active power

response to a high or low frequency event (regardless of the number of power generating modules in operation) the reference active power Pref is therefore assigned:

- Pref is by default the actual active (at the moment of activation) for PPM.
- Pref can be alternatively defined as Pmax for PPM expected to operate mostly at or near maximum capacity (example for offshore wind farms connected to Transmission Network);

For SPGM:

Parameters (SPGM)	For power increase	For power decrease
Step response time	≤ 5 minutes for an increase of active power of 20 % Pmax (a slow reaction is not applicable in the case of an increase shortly –few second- following a decrease phase)	≤ 8 seconds for a decrease of active power of 45% Pmax
Settling time	≤ 6 minutes for an increase of active power (a slow reaction is not applicable in the case of an increase shortly –few second- following a decrease phase)	≤ 30 seconds for a decrease of active power

Commented [A59]: Not applicable at low frequency

For PPM:

Parameters (PPM)	For power increase	For power decrease
Step response time	<p><i>For wind generation:</i> ≤ 5 seconds for an increase of active power of 20 % Pmax</p> <p><i>For the rest:</i> ≤ 10 seconds for an increase of active power of 50 % Pmax</p>	≤ 2 seconds for a decrease of active power of 50 % Pmax
Settling time	≤ 30 seconds for an increase of active power	≤ 20 seconds for a decrease of active power

Commented [A60]: Not applicable at low frequency

Commented [A61]: Impossible for wind due to pitching.

Commented [A62]: The text must be replaced by the following
'For wind generation :
 - <= 5 seconds for an increase of active power $dP \leq 20\%P_n$.
 This applies depending on the available primary energy and for $P_{actual} >= 50\%P_n$.
 - For $P_{actual} < 50\%P_n$, the rise time has to be as fast as possible (according to the technical possibilities as given by the manufacturers).'
 Explanation : in the case of wind energy, ability of the wind turbines to increase the active power is greatly depending on the actual active power, and in the wind condition. At low actual power (or low wind) the response time is longer.

5.1.3 Frequency Sensitive Mode [Art. 15.2.d]

The setting parameters for the frequency sensitive mode are summarized in below:

Parameters	Values and ranges
Active power range $ \Delta P /P_{max}$	A range between 2% and 10%
Frequency response insensitivity	$ \Delta f $ Maximum 10 mHz
	$ \Delta f /f$ Maximum 0,02 %
Frequency response deadband	0 mHz and adjustable between 0 et 500 mHz (a combined response insensitivity, possible delay and response dead band shall be limited to 10 mHz)
Droop s_i	Adjustable between 2% and 12% to guaranty a full activation $ \Delta P /P_{max}$ for the maximum frequency activation (200 mHz)
Pref	Defined as Pmax

Commented [A63]: We prefer that the current values are maintained.

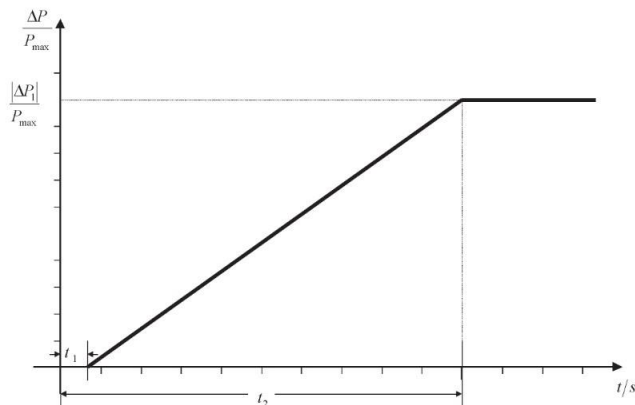


Figure 15 Active power response capability

With respect to the paragraph 15.2.(d).iii, the requirements in term of time response characteristics as described in the Figure 4 are defined as below:

- t_1 : Maximum 2 seconds for PGM with inherent inertia and Maximum 500 milliseconds for PGM without inherent inertia
- t_2 : Maximum 30 seconds (15 seconds for 50% of full active power activation)
- full activation duration: minimum 15 minutes

5.1.4 Frequency restoration control [Art 15-2.e]

Specifications aligned with synchronous area TSOs in compliance with the System Operation Guidelines (Articles 154, 158, 161, 165) [9] and currently applicable requirement of Elia, are to be agreed during the connection process with the relevant system operator (it might be the (C)DSO or Elia) on a case by case level and fixed in the individual connection contract.

5.1.5 Real-time monitoring of FSM [Art 15-2.g]

Defined coherently as per the System Operation Guidelines (Article 47) [9] and currently applicable requirement of Elia are to be agreed during the connection process with the relevant system operator (it might be the (C)DSO or Elia) on a case by case level and fixed in the individual connection contract.

Commented [A64]: To add : respecting arguments (or rules) regarding cyber security.

5.1.6 Automatic disconnection for voltage outside ranges [Art 15-3]

The automatic disconnection due to voltage level is not requested in a generic manner.

This requirement is considered site specific. The activation, values and settings of this functionality should be agreed during the connection process by the relevant system operator in coordination with the relevant TSO on a case by case level and fixed in the individual connection contract with the relevant system operator. The grid user will have to validate the settings of the disconnection relays with the relevant TSO.

Automatic reconnection to the network after a disconnection is not allowed and should be coordinated with the relevant TSO.

5.1.7 Rates of change of active power output [Art 15-6(e)]

Minimum and maximum active power ramping **limits** (upward and downward) should be agreed during the connection process by the relevant system operator in coordination with the relevant TSO on a case by case level and fixed in the individual connection contract with the relevant system operator. The ramping limits are to be defined site specifically taking into consideration the prime mover technology in compliance the System Operation Guidelines [9]. These limits are to be defined by the relevant system operator in coordination with the TSO.

Commented [A65]: Incorrect wording: 'power ramping limits' should be replaced by 'power ramping rates'.

Commented [A66]: Legal reference not correct. To add : GL SO Art.137.4

5.2 System restoration [Art 15-5]

Different from the current Federal Grid Code [4], the NC RfG asks for more strict behaviour for system restoration.

5.2.1 Capability to take part in island operation [Art 15.5(b)]

The PGMs of type C are not required to take part to island operation. **Nevertheless they are required to be able to trip to houseload and be able to quick-resynchronize as specified in 15-5(c).**

Commented [A67]: Not acceptable, a remuneration is required before offering such capabilities. See remark at the introduction regarding RfG art 1.

5.2.2 Quick resynchronization capability [Art 15-5(c)]

More specifically with regard to quick re-synchronisation capability:

- i. In case of disconnection of the power-generating module from the network, the powergenerating module shall be capable of quick re-synchronization in line with the protection strategy agreed between the relevant system operator in coordination with the relevant TSO and the power-generating facility.

The quick re-synchronization strategy is to be agreed with the relevant TSO on a case by case basis.

- ii. A power-generating module with a minimum re-synchronization time greater than 15 minutes after its disconnection from any external power supply **must be designed to trip to houseload from any operating point** in its P-Q-capability diagram. In this case, the identification of houseload operation must **not be based solely** on the system operator's switchgear position signals.

Commented [A68]: See earlier remark.

Commented [A69]: What are the other criteria?

The strategy of identification of houseload operation is to be agreed with the relevant TSO on a case by case basis.

- iii. Power-generating modules **shall be capable of continuing operation following tripping to houseload, irrespective of any auxiliary connection to the external network.** The minimum operation time shall be specified by the relevant system operator in coordination with the relevant TSO, taking into consideration the specific characteristics of prime mover technology.

Commented [A70]: Not according to RfG : only imposed in case the re-synchronisation takes more than 15 minutes. See also point ii.

For PGMs connected to TSO network, the minimum operation time is to be defined during the connection process.

5.3 Instrumentation, simulation and protection

5.3.1 Loss of angular stability or loss of **excitation control** [Art 15.6(a)]

The power generating facility owner and the relevant system operator in coordination with the TSO shall agree during the connection proces about the criteria to detect loss of angular stability or loss of control and consequent disconnection of the unit. **These parameters will be taken in the appendices of the individual connection agreement.**

Commented [A71]:

Commented [A72]: What in case no agreement can be reached?

5.3.2 Instrumentation [Art 15.6(b)]

The quality of supply parameters, the triggers for activation of fault recorders and power oscillation and relative sampling rates and the modality of access to the recorded data is to be defined in agreement with the TSO and/or relevant system operator (in accordance with art 15-6) during the connection process. **These parameters will be taken in the appendices of the individual connection agreement.**

Commented [A73]: What in case no agreement can be reached?

5.3.3 Simulation models [Art 15.6(c)]

Simulation models able to reflect the behaviour of the power generating module in steady state and electromechanical dynamic simulation (phasor-based) are required by ELIA for all units. A model to represent Electro Magnetic Transient phenomena can be required on a site specific base for every concerned unit.

The format of the model, as well the provision of documentation and short circuit capacity should be coordinated by the relevant system operator with the TSO during the connection process. **These parameters will be taken in the appendices of the individual connection agreement.**

Commented [A74]: What in case no agreement can be reached?

5.3.4 Devices for system operation and security [Art 15.6(d)]

The installation of additional devices for system operation and security should be agreed between the RSO or TSO and the PGFO on a site specific base.

5.3.5 Earthing of the neutral point at the network side of the step-up transformer [Art 15.6(f)]

The relevant system operator shall specify the earthing arrangement of the neutral-point at the network side of step-up transformers during connection process. These parameters will be taken in the appendices of the individual connection agreement.

5.4 Voltage control mode (for SPGM and PPM) [Art 19-2(a) and Art 21.3(d)]

This requirement should be met at the connection point.

By default the control mode is a voltage droop/slope mode. However site specific (during the grid conformity process with the relevant system operator; e.g. **EDS**) a different control mode can be requested/agreed.

Commented [A75]: Who is EDS?

These specifications are given in line with the FGC Art. 69. The power generating modules of types C and D are considered **regulating units**. They must be able to adapt their reactive power injected at the *connection point*:

Commented [A76]: Definition?

- Automatically in case of slow or fast variations of the grid voltage. This has to happen according to a reactive droop (FGC Art. 73);
- Through change of the controller setpoint on request of the Transmission System Operator. This request is quantified in MVAR measured at the connection point. The change of setpoint shall be initiated immediately after reception of the request;
- Reactive power exchange with the TSO network to control the voltage covering at least the 0.90 to 1.10 pu voltage range should be in steps not greater than 0.01 pu;
- The reactive power output shall be zero when the grid voltage value at the connection point equals the voltage setpoint.

Upcc (p.u.)

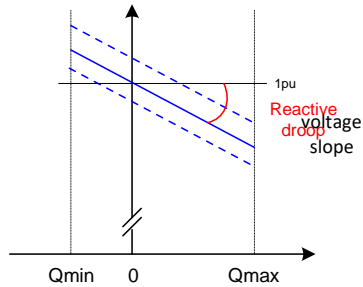


Figure 16 : Principle of the voltage and reactive power control

Automatic voltage control has to fulfil a reactive droop requirement (Figure 16). On request of the Transmission System Operator, the setpoint of the controller can be modified in real-time, and the operating point is to be shifted to a parallel line (dashed) with the same slope (illustrated in Figure 15c). The control loop gain will be agreed between the Transmission System Operator and the PGM operator (before first energization) so that a_{eq} lies between 18 and 25, as expressed in the following:

$$a_{eq} = \frac{Q_{net}}{U_{net}} \cdot 0,45 \cdot \frac{P_{nom}}{U_{norm,exp}}$$

Commented [A77]: This is a value from the old law and has to be modified in coherence with the current requirements for reactive power

Where

- U_{net} is the voltage measured at the Connection Point
- $U_{norm,exp}$ is the normal exploitation voltage at the Connection Point
- Q_{net} is the injected reactive power measured at the Connection Point

5.5 Type C SPGM Requirements

5.5.1 Reactive power capability SPGMs [Art 18-2]

This requirement should be met at the connection point.

All SPGMs of type C (and type D) should be compliant with the requested reactive power capabilities of the U-Q/Pmax diagram in Figure 17. For every connection demand, it should be proven that the SPGM is able to operate within the range shown in the figure below. The maximum voltage value of 1.118pu should be considered as 1.05pu in case of connection to voltage level above 300kV.

Note that the available capability of the SPGM (which could be wider than the minimum requirement) should be communicated, demonstrated and put at disposal of the relevant system operator.

The owner of the SPGM is not allowed to refuse the use of the reactive capability without a technical justification. The unit is therefore expected to not limit its capabilities to comply with the minimum requirement but to use the full capability to support the system stability as stated in its agreement. The SPGM should be in state to deliver the reactive capacity shown in figure above for the whole operating range of active power, conform to art 18.2(c).

The speed of reaction within the capability curve is site specific and will be determined during the connection conformity process (e.g. EDS) and specified in the contractual agreement.

Commented [A78]: For consistency best to change to: *the required reactive capabilities should be met at the HV side of the step up transformer if existing; otherwise it should be met at the alternator terminals*

In addition Art.18.2 of RfG indicating the additional reactive power needed for compensation for the HV-line between the connection point and the HV-terminals *shall be provided by the responsible owner of that line.* The owner in Belgium is always ELIA.

Commented [A79]: RfG (figure 7) imposes a max. value of 1.1 pu. To correct.

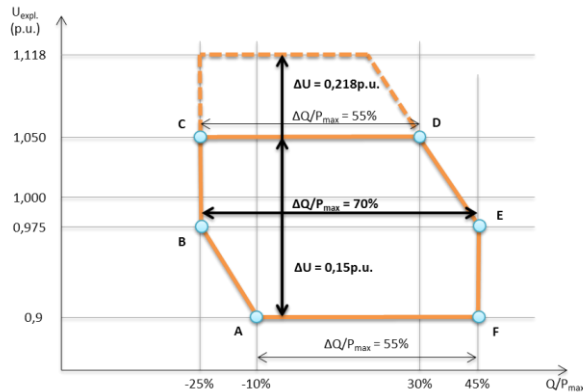


Figure 17: Capability curve for SPGM type C and D.

Commented [A80]: Generators may have high restriction for absorbing Q with low voltage (core end heating from axial flux). The limitation of the stator current is in this case proportional to the square of the terminal voltage.

5.5.2 Voltage control requirements for SPGM type C

The proposed requirements for voltage control for type C units are in line with the current federal grid code (Art. 75) [4] for which regards the functionalities and parameter settings of the automatic voltage regulator with regard to steady-state voltage and transient voltage control and the specifications and performance of the excitation control system. The functionality shall include:

- bandwidth limitation of the output signal to ensure that the highest frequency of response cannot excite torsional oscillations on other power-generating modules connected to the network;
- an underexcitation limiter to prevent the AVR from reducing the alternator excitation to a level which would endanger synchronous stability;
- an overexcitation limiter to ensure that the alternator excitation is not limited to less than the maximum value that can be achieved whilst ensuring that the synchronous power-generating module is operating within its design limits;
- a stator current limiter;
- a Power System Stabilizer (PSS) function to attenuate power oscillations, requested by the relevant TSO (i.e. the activation and tuning of the PSS function will be agreed depending on the connection point, size and the characteristic of the SPGM).

5.6 Type C PPM Requirements

5.6.1 Synthetic inertia for PPM [Art 21-2]

Synthetic inertia functionality is not required for the current Grid Code implementation due to low maturity of the available technology and limitations in terms of minimum time response which could result in adverse effects.

5.6.2 Reactive capabilities - PPM [Art 21-3(a-c)]

This requirement should be met at the connection point.

A PPM of type C shall be capable of delivering reactive power within the Q-P profile described in Figure 17.

For every voltage at the Connection Point between 90 % and 111.8 % of U_{nom} and for any value of the active power output between P_{min} (0.2 p.u. of P_{nom}) and P_{nom} , the wind park shall be able to produce or consume - at least - any reactive power at the connection point within the area limited by Q1, Q2, Q3 and Q4 (Figure 18).

Commented [A81]: Change to: *the required reactive capabilities should be met at the HV side of the step up transformer if existing; otherwise it should be met at the alternator terminals*

Commented [A82]: Not according to RfG figure 8.

Commented [A83]: So not for other types. What applies for other sources than wind farms?

This range has an obligated minimum span of 0.6 p.u. of P_{nom} , but can move within an area of $[-0.3$ p.u. of P_{nom} , $+0.35$ p.u. of $P_{nom}]$ when accepted by ELIA, based on the connection point, size and the characteristic of the installation.

For all values between the 90% and the 111.8% for nominal voltage below 300kV (or 90% and 105% for nominal voltage above 300kV) voltage ranges, it is requested that the wind park could participate in voltage regulation at least in the above mentioned reactive power range (as is represented in the UQ/Pmax profile in Figure 9); for values outside of the 90% and the 111.8% for nominal voltage below 300kV (or 90% and 105% for nominal voltage above 300kV) voltage ranges, it is requested that the wind park could participate in voltage regulation to the maximum of the technical capabilities of the installation.

For every voltage value, at the Connection Point, between 90 % and 111.8% of U_{nom} for nominal voltage below 300kV (or 90% and 105% for nominal voltage above 300kV) and for any value of active power output between P_0 (equal to 0.0263 p.u. of P_{nom}) and P_{min} , the minimum range of operating point for which reactive power shall be controlled is defined by the two values of the power factor computed by the points $(Q1, 0.2 * P_{nom})$ and $(Q2, 0.2 * P_{nom})$.

For every voltage, at the Connection Point, between 90 % and 111.8 % of U_{nom} for nominal voltage below 300kV (or 90% and 105% for nominal voltage above 300kV) and for any value of active power output below P_0 , the reactive power can be uncontrolled, however, injected/absorbed values must be limited within a range of $Q = [-0.0329 ; +0.0329]$ p.u. of P_{nom} that is represented by the shaded area in the Figure 18. Error! Reference source not found.

Commented [A84]: See above

Commented [A85]: Wrong reference

Commented [A86]: Avoid repeating the same requirement. (5 times in this paragraph).

Commented [A87]:

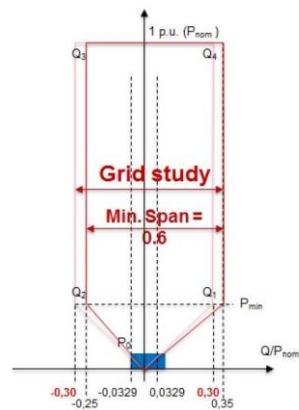
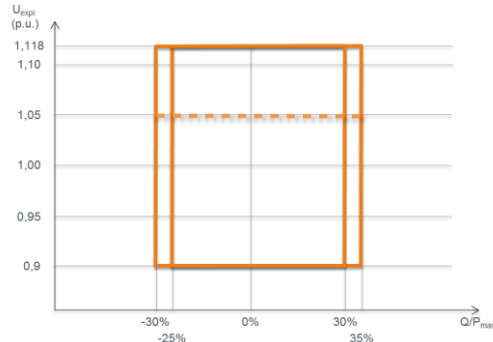


Figure 18: Reactive power capability for a Type C and D PPM.



³ FGC Article 209 §3: 3,29 % = 10 % of the reactive range at $\cos(\phi) = 0.95$.

Figure 19: U-Q/Pmax profile for a type C PPM (dashed for nominal voltages above 300kV).

Commented [A88]: 1.118 => 1.10

Note that the available capability of the PPM (which could be wider than the minimum requirement) should be communicated, demonstrated and put at disposal of the relevant system operator. The owner of the PPM is not allowed to refuse the use of the reactive capability without a technical justification. The unit is therefore expected to not limit its capabilities to comply with the minimum requirement but to use the full capability to support the system stability as stated in its agreement. The speed of reaction within the capability curve is site specific and will be determined during the connection conformity process (e.g. EDS) and specified in the contractual agreement.

5.6.3 Voltage control - PPM [Art 21-3 (d) and (e)]

This requirement should be met at the connection point.

The PPM shall be capable of providing reactive power automatically by either voltage control mode, reactive power control mode or power factor control mode.

The requirement for the prioritizing of active or reactive power contribution is to be defined as site specific by the relevant system operator. It has to be agreed during the connection process with the relevant system operator in coordination with the relevant TSO on a case to case basis and fixed in the individual connection contract with the relevant system operator.

6 Type D Requirements

In addition to the specifications for type C, the following is requested.

Commented [A89]: Change to "in addition to relevant requirements for..." ; Some requirements for are not relevant for D or even contradictory

6.1 Voltage Control

6.1.1 Voltage withstand capability [Art 16-2(a & b)]

This requirement should be met at the connection point.

The following voltage withstand capability are proposed in line with the RfG.

	Voltage Range	Time period for operation
Voltage ranges below 300kV	0.85 pu – 0.90 pu	60 minutes
	0.90 pu – 1.118 pu	Unlimited
	1.118 pu – 1.15 pu	20 minutes
Voltage ranges above 300kV	0.85 pu – 0.90 pu	60 minutes
	0.90 pu – 1.05 pu	Unlimited
	1.05 pu – 1.10 pu	20 minutes

Commented [A90]: I propose to add at Art. 6.1.1 the following comment : "At the latest European Stakeholder Committee, ENTSOE stated officially: o to ask for a modification of the IEC standard 400 kV to allow an overvoltage of 440 kV during 20 minutes or more o that it has never been the intention of ENTSOE to impose the IEC 550 kV standard to comply with the 440 kV requirement during 20 minutes or more. o that PGMs may use identical apparatus as the grid operators do." ELIA has to respect this statement and allow the installation of 400 kV material according to the IEC in force at that moment.

The following base values are to be considered for PGM connected to TSO network:

- 400kV
- 220kV □ 150kV
- 110kV
- 70kV
- 36kV

In case of broader or longer voltage withstand capabilities technically and economically feasible, the owner of the installation should put this at disposal of the relevant system operator.

Commented [A91]: According to RfG Art. 18 figure 7, reactive power requirements apply only up to 1.1 pu. What is the reactive behavior in the range 1.1 pu - 1.15 pu?

Commented [A92]: These requirements only apply on type D as it is inserted under 'Type D requirements'. This table should be inserted earlier in the document as it has also to apply on all types of PGM's. On top of that it should be specified that those are the values for 1 pu.

6.1.2 Automatic disconnection for voltage outside ranges [Art 162(c)]

No automatic disconnection is foreseen as a generic requirement.

The terms and settings for automatic disconnection should be agreed during the connection process with the PGFP by the relevant system operator in coordination with the relevant TSO on a case by case basis and fixed in the individual connection contract with the relevant system operator.

Commented [A93]:

Commented [A94]: Should not be an obligation. Remuneration is to be foreseen.

6.2 Resynchronization [Art 16-4]

The relevant system operator and the PFGO should agree on the settings of the synchronization devices during the connection process on a case by case basis and fixed in the individual connection contract with the relevant system operator.

Commented [A95]: What is the general rule? I would add here that the TSO will endeavour or mobilise all means possible in order to reconnect the generator to the grid as soon as technically possible.

6.3 Type D SPGM Requirements

6.3.1 Fault-ride through for symmetrical and asymmetrical faults – SPGM [Art 16-3]

This requirement should be met at the connection point.

The SPGM unit should be able to support the network during fast transient voltages and network shortcircuits for which the profile of the voltage versus time is referred as Fault-Ride-Through (FRT). SPGM unit shall fulfil the requirements in the Figure below (the evolution of the minimum voltage at the Connection Point), where the SPGM shall remain connected to the grid as long as the voltage of the phase having the lower voltage is above the profile shown in the Figure below. **Error! Reference ource not found.**

Commented [A96]: As mentioned in point 2. This is not possible for SPGM between 25 MW and 75 MW connected above 110kV.

It is recommended however to remain connected as long as the technical capability of the SPGM would allow. The same profile applies for asymmetrical faults.

Commented [A97]:

The proposed fault-ride-through parameters⁴ following FRT are presented in the table below. A voltage $U=1$ pu represents the rated voltage (phase-to-phase) at the connection point.

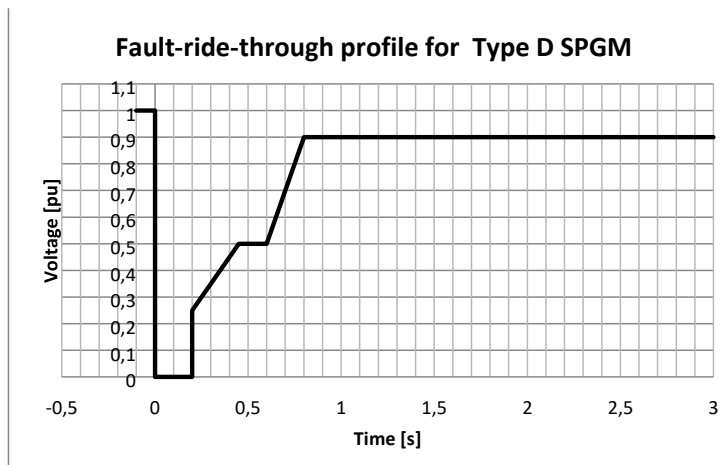


Figure 20 :FRT requirement for SPGM type D

Tabel 1 : Parameters of the FRT requirements for SPGM of type D

Voltage parameters [pu]	Time parameters [seconds]

⁴ Note that the parameter are not the coordinates of the FRT curve but must be interpreted following the specification of the RfG, art. 14.3 and presented, for information, in appendix I.

Uret= 0	tclear= 0.2
Uclear = 0.25	trec1 =0.45
Urec1= 0.5	trec2 =0.6
Urec2 = 0.9	trec 3=0.8

Commented [A98]: See earlier remarks regarding Tclear.

The parameters considered for fault-ride through capability calculations (e.g. pre and post fault short circuit capacity, pre-fault operating point of the PGM...) are communicated by the TSO on request of the power-generating facility owner during the connection process.

6.3.2 Voltage stability SPGM [Art 19-2]

In line with the current federal grid code (art 75) [4] for which regards the functionalities and parameter settings of the automatic voltage regulator with regards to steady-state voltage and transient voltage control and the specifications and performance of the excitation control system. The latter shall include:

Commented [A99]: Unclear, wrong reference.

- i. bandwidth limitation of the output signal to ensure that the highest frequency of response cannot excite torsional oscillations on other power-generating modules connected to the network;
- ii. an underexcitation limiter to prevent the AVR from reducing the alternator excitation to a level which would endanger synchronous stability;
- iii. an overexcitation limiter to ensure that the alternator excitation is not limited to less than the maximum value that can be achieved whilst ensuring that the synchronous powergenerating module is operating within its design limits;
- iv. a stator current limiter; and
- v. a PSS function to attenuate power oscillations, requested by the relevant TSO (: the activation and tuning of the PSS function will be required depending on the connection point, size and the characteristic of the concerned SPGM).

6.3.3 Technical capabilities to support angular stability under fault conditions for SPGM [Art 19-3]

No generic capabilities regarding SPGM to aid angular stability under fault condition are requested. The TSO and the PFGO should agree on these capabilities during the connection process on a case by case basis and fixed in the individual connection contract with the relevant TSO.

6.4 Type D - PPM

6.4.1 Fault-ride through for symmetrical and asymmetrical faults – PPM [Art 16-3]

This requirement should be met at the connection point.

The PPM unit should be able to support the network during fast transient voltages and network shortcircuits for which the profile of the voltage versus time is referred as Fault-Ride-Through (FRT). PPM unit shall fulfil the requirements in Figure 219, where the PPM unit shall remain connected to the grid as long as the voltage of the phase having the lower voltage is above the profile of the figure below. It is recommended however to remain connected as long as the technical capability of the PPM would allow. The same profile applies for asymmetrical faults.

The proposed fault-ride-through parameters are presented in Tabel 2.

A voltage $U=1$ pu represents the rated voltage (phase-to-phase) at the connection point.

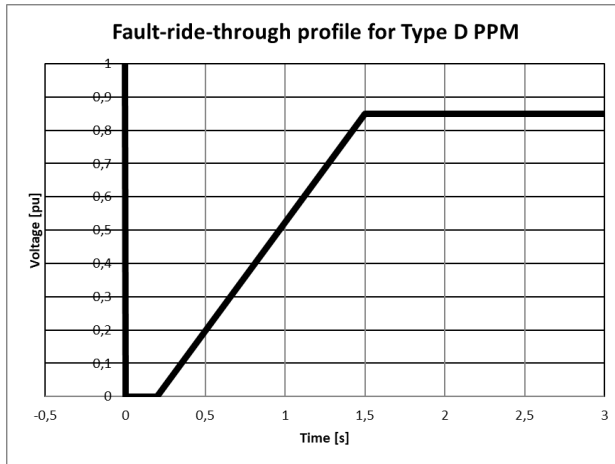


Figure 21: FRT requirement for PPM type D.

Table 2 : Parameters of the FRT requirements for PPM of type D.

Voltage parameters [pu]	Time parameters [seconds]
$U_{ret}=U_{clear}=U_{ret1}=0$	$T_{clear}=t_{rec1}=t_{rec2}=0.2$
$U_{rec2} = 0.85$	$t_{rec3}=1.5$

Commented [A100]: See earlier remarks.

7 Acronyms

SGU	Significant Grid User
PGM	Power Generating Module
LFSM	Limited Frequency Sensitive Mode
FRT	Fault Ride Through
PGM	Power Generating Module
PPM	Power Park Module
SPGM	Synchronous Power-Generating Modules
RfG	Requirement for Grid connection of generators
NCC	Elia National Control Center
PGFO	Power Generating Facility Owner
LOM	Loss Of Main

8 References

- [1] 'Network Code Requirements for Generators' or 'NC RfG': Commission Regulation (EU) 2016/631 of 14 April 2016 establishing a network code on requirements for grid connection of generators, <http://eurlex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32016R0631&from=EN>
- [2] 'Network Code on Demand Connection' or 'NC DCC': Commission Regulation (EU) 2016/1388 of 17 August 2016 establishing a Network

Code on Demand Connection, <http://eur-lex.europa.eu/legalcontent/EN/TXT/PDF/?uri=CELEX:32016R1388&from=EN>

[3] 'Network Code on High Voltage Direct Current' or 'NC HVDC': Commission Regulation (EU) 2016/1447 of 26 August 2016 establishing a network code on requirements for grid connection of high voltage direct current systems and direct current-connected power park modules, <http://eur-lex.europa.eu/legalcontent/EN/TXT/PDF/?uri=CELEX:32016R1447&from=EN>

[4] Federal Technical Reglement-
19 DECEMBER 2002. — Koninklijk besluit houdende een technisch reglement voor het beheer van het transmissienet van elektriciteit en de toegang ertoe, Arrêté royal établissant un règlement technique pour la gestion du réseau de transport de l'électricité et l'accès à celui-ci, <http://www.elia.be/~media/files/Elia/publications-2/gridcodes/Technisch%20realement%20Federaal%202002.pdf>.

[5] Presentation FOD/SPF Energy in WG Belgian Grid (in Dutch): http://www.elia.be/~media/files/Elia/usersgroup/WG%20Belgian%20Grid/20170307%20WG%20Belgian%20Grid/FOD_Vision_for_FederalGridCode.pdf

Minutes of Meeting WG Belgian Grid 7th March 2017 (in French): http://www.elia.be/~media/files/Elia/usersgroup/WG%20Belgian%20Grid/20170421_WG%20BG/20170307_PV_WGBG_FR_FINAL_WRITTEN-APPROVED.pdf

[6] Report On "Public Consultation: Maximum Capacity Thresholds For Types B, C And D Power-Generating Modules", September 2017, http://www.elia.be/~media/files/Elia/About-Elia/Publication/Report_public_consultation_Limits_ABCD_vENG.pdf

[7] ENTSO-E Guidance document for national implementation for network codes on grid connection : Parameters of Non-exhaustive requirements, 16 November 2016: https://www.entsoe.eu/Documents/Network%20codes%20documents/NC%20RfG/161116_IGD_General%20guidance%20on%20parameters_for%20publication.pdf

[8] Frequency Stability Evaluation Criteria for the Synchronous Zone of Continental Europe, SPD WG, March 2016

[9] ENTSO/e System operation guidelines, May 2016.

Formatted: Dutch (Belgium)

Field Code Changed

Formatted: Dutch (Belgium)

Field Code Changed

Formatted: Dutch (Belgium)

Field Code Changed

Formatted: Dutch (Belgium)

Field Code Changed

Formatted: Dutch (Belgium)

Formatted: Dutch (Belgium)

Formatted: Dutch (Belgium)

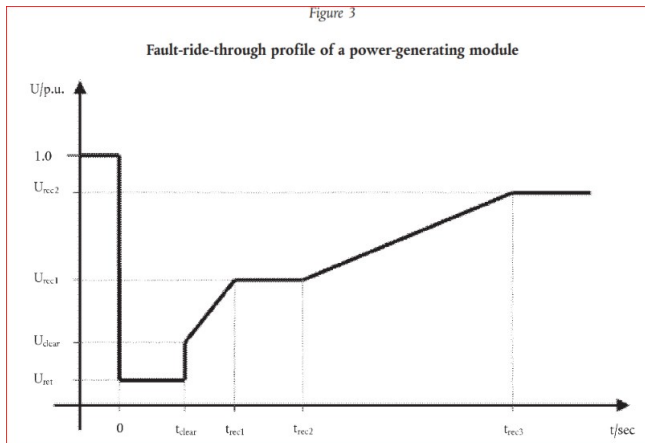
Field Code Changed

Formatted: Dutch (Belgium)

Commented [A101]: Please refer to the ENOVER discussion on type A/B

Commented [A102]: link to be added as codes above

9 Appendix I – Definition FRT profile (extract from Art. 14.3 RfG[1])



10 Appendix II - List of non-exhaustive articles for RfG

This list is extracted from ENTSO-E Guidance document for national implementation for network codes on grid connection : Parameters of Non-exhaustive requirements [7]



**PROPOSAL FOR NC DCC REQUIREMENTS OF
GENERAL APPLICATION**

TABLE OF CONTENTS

Table of Contents	222
Introduction	444
Scope of application	666
Elia proposal of general requirements	666
1. Connection of transmission-connected demand facilities, transmission-connected distribution facilities and distribution systems	666
1.1. General Frequency Requirements [Art. 12]	666
1.1.1. Frequency requirements [Art. 12 – 1].....	666
1.1.2. Extended frequency range [Art. 12 – 2].....	777
1.2. General voltage requirements [Art. 13]	777
1.2.1. Voltage requirements in case of voltage level at the connection point between 110kV and 400kV [Art. 13 – 1].....	777
1.2.2. Automatic voltage disconnection [Art. 13 – 6].....	888
1.2.3. Voltage requirements for transmission-connected (closed) distribution systems in case of a voltage level at the connection point below 110kV [Art. 13 – 7]	888
1.3. Short-Circuit requirements [Art. 14]	888
1.3.1. Short-circuit withstand capability [Art. 14 – 1].....	888
1.3.2. Communication of a change in maximum short-circuit current [Art. 14 – 3 , 14 – 5, 14 – 8, 14 – 9]	999
1.4. Reactive Power Requirements [Art. 15]	999
1.4.1. Reactive power exchange between the transmission system and transmission-connected demand facilities [Art. 15 – 1 (a)].....	999
1.4.2. Reactive power exchange between the transmission system and transmission-connected (closed) distribution systems [Art. 15 -1 (b), Art. 15 – 1 (c)]	104040
1.4.3. Reactive power exchange between the transmission system and transmission-connected (closed) distribution systems at low active power flow [Art. 15 – 2].....	124242
1.4.4. Metrics to express the reactive power capability ranges [Art. 15 – 1 (d)].....	134343
1.5. Protection requirements [Art. 16]	134343
1.5.1. Devices and settings required to protect the transmission system [Art. 16 – 1].....	134343
1.6. Control requirements [Art. 17]	134343
1.6.1. Schemes and settings of different control devices [Art. 17 – 1]	134343
1.7. Information exchange [Art. 18]	144443
1.7.1. Specifications of information exchange equipment [Art. 18 – 1, 18 – 2, 18 – 3].....	144443
1.8. Demand disconnection and demand reconnection [Art. 19]	144444
1.8.1. Low Frequency Demand Disconnection [Art. 19 – 1 (a), Art. 19 – 1 (b), Art. 19 – 1 (c)]	14
1.8.2. Low Voltage Demand Disconnection [Art. 19 – 2 (a), Art. 19 – 2(b)]	15
1.8.3. Blocking of on load tap changers [Art. 19 – 3 (a), Art. 19 – 3 (b)]	15
1.8.4. Reconnection [Art. 19 – 4 (a), Art. 19 – 4 (b), Art. 19 – 4 (c)]	15
1.9. Power quality [Art. 20]	15

1.10. Simulation models [Art. 21]	16
1.10.1. Models or equivalent information showing the behavior in steady and dynamic states [Art. 21 – 2, 21 – 3]	16
1.10.2. Recordings to compare with model [Art. 21 – 5]	16
2. Connection of demand units used by a demand facility or a closed distribution system to provide demand response services to system operators	17
2.1. Demand units providing active power control, reactive power control and transmission constraint management [Art. 28]	17
2.1.1. Definition of an extended frequency range [Art. 28 – 2 (a)]	17
2.1.2. Definition of voltage range if connected at a voltage below 110kV [Art. 28 – 2 (c)]	17
2.1.3. Time period to modify power consumption [Art. 28 – 2 (f)]	17
2.1.4. Notification of changes in demand response capacity [28 – 2 (i)]	17
2.1.5. Technical specifications to enable transfer of information [Art. 28 – 2 (e), 28 – 2 (l)]	17
2.1.6. Definition of the ROCOF maximum value [Art. 28 – 2 (k)]	17
2.2. Demand units with demand response system frequency control [Art. 29]	18
2.2.1. Definition of an extended frequency range [Art. 29 – 2 (a)]	18
2.2.2. Definition of voltage range if connected at a voltage below 110kV [Art. 29 – 2 (c)]	18
2.2.3. Definition of allowed frequency dead band [Art. 29 – 2 (d)]	18
2.2.4. Maximum frequency deviation to respond [Art. 29 – 2 (e)]	19
2.2.5. Definition of the rapid detection and response to frequency system changes [Art. 29 – 2 (g)]	19
2.3. Demand units with demand response very fast active power control [Art. 30] ...	19
References	20
Appendix – List of non-exhaustive requirements for NC DCC	21

INTRODUCTION

Article 6(4) of the NC DCC [1] states that the relevant system operator or the TSO submits a proposal for requirements of general application (or the methodology used to calculate or establish them), for approval by the competent entity, within two years of entry into force of the NC DCC, i.e. 7 September 2018. A similar requirement is included in the two other connection Network Codes, namely in Art. 7(4) of the NC RfG [2] and in Art. 5(4) of the NC HVDC [3]. The most stringent deadline for Elia, herein, is 17 May 2018, which is two years after the NC RfG entered into force as first connection network code.

The aim of this document is to synthesize the technical proposal of Elia, as relevant system operator or relevant TSO, regarding the Belgian implementation of the non-exhaustive requirements stated in the in the NC DCC. This document is the final version of the proposal for requirements of general application (hereafter named as 'general requirements', in accordance with Art. 6(4) of the NC DCC.

For the requirements related to transport- (closed) distribution system interface DSOs and CDSO's were largely involved in developing the TSO proposal. However these requirements have to be considered as an Elia proposal (as relevant TSO)

For the requirements related demand facility providing demand response services, the proposal is mainly focusing on requirements set by Elia, as (relevant) TSO or relevant system operator but the public DSOs were largely involved in developing the TSO proposal and in defining their own implementation proposals (for demand facility providing demand response services connected to the distribution system). Therefore, part of these requirements are also set by the public DSOs, as relevant system operator.

To facilitate the implementation of the NC DCC requirements, Elia and the public DSOs aligned as much as possible to increase the coherency and avoid as much as possible discrimination between a transmission-, or distribution-connected demand facility providing demand response services to system operators in terms of technical requirements and legal readability.-

On 17 May 2018, Elia will submit the general requirements proposals for NC DCC, but also for NC RfG and NC HVDC to the competent authorities together with the proposal of the amended Federal Grid Code [4] and the formal proposal on maximum capacity thresholds of type B, C and D PGM. Elia will organize beforehand a public consultation for all deliverables in March-April 2018, except for the public consultation on the maximum capacity thresholds B, C and D, that already took place from 19 May till 20 June 2017. This approach is in line with the vision of the Belgian Federal Administration (FOD/SPF Energy) [5].

This document represents the most recent position of Elia taken after discussions with the stakeholders in each of the relevant topics. During the last months, this document was gradually completed and presented to stakeholders, especially during the Federal Grid Code workshops until all non-exhaustive general requirements were included.

The public DSOs were also largely involved in developing the TSO proposal or in defining their own implementation proposals for units connected to the distribution grid. To facilitate the implementation of these Network Code requirements, Elia and the public DSOs aligned as much as possible to increase the coherency between a transmission-, or distribution connected unit in terms of technical requirements and legal readability. For aspects of the general requirements relevant for CDSOs, Elia has also been interacting with CDSOs.

This document should be considered as a technical and not legally binding document, focusing on the clarification of various technical general requirements that will be reflected

Commented [A1]: Wat is de meerwaarde van deze paragraaf, aangezien niet alles onderschreven wordt door de distributienetbeheerders.

Commented [A2]: Verwijderen: discriminatie moet t allen tijde vermeden worden.

in various grid codes, contracts, terms and conditions, regulatory documents and/or technical prescriptions.

The document follows the same article order as in the NC DCC: the proposal is organized per technical topic and per demand connection category.

The scope of this document contains especially, but is not limited to, the implementation proposal of the non-exhaustive general requirements in the NC DCC. To increase its readability, this document might also contain NC exhaustive requirements, implementation proposals of non-exhaustive requirements of the other connection NC, or other specific national/regional requirements for information purposes only, but certainly does not cover all of them.

With respect to the complete list of non-exhaustive requirements to be proposed as general requirements, Elia is taking as reference the ENTSO-E implementation guidance document (IGD) on 'Parameter of Non-exhaustive requirements' [6] to be defined by the (relevant) TSO and the relevant system operator. This document does not only mention the parameters to be defined per topic, but also which article of each connection NC should be considered as non-exhaustive and who should be the relevant system operator to define an implementation proposal. The TSO, DSOs and CDSOs can be considered as 'relevant system operator', depending on the requirement.

SCOPE OF APPLICATION

As mentioned in article 3 of the NC DCC, the connection requirements set out in the NC DCC apply to:

- a) New transmission-connected demand facilities;
- b) New transmission-connected distribution facilities;
- c) New distribution systems, including new closed distribution systems;
- d) New demand units, used by a demand facility or a CDS to provide demand response services to relevant system operators and relevant TSOs

These categories do not include storage devices except for pump storage power generating modules (art. 5(1) and 5(2) of the NC DCC).

We refer to articles 3 and 4 of the NC DCC for more information on the application of general requirements to existing facilities and systems, to demand facilities and closed distribution systems with more than one demand unit.

Commented [A3]: Only for PGMs with separate pumping and generating machines. See also RfG Art. 6.2

ELIA PROPOSAL OF GENERAL REQUIREMENTS

1. Connection of transmission-connected demand facilities, transmission-connected distribution facilities and distribution systems

1.1. General Frequency Requirements [Art. 12]

1.1.1. Frequency requirements [Art. 12 – 1]

The frequency withstand capability is defined in accordance with NC DCC Annex I and presented in the table below:

Frequency Range	Duration
47,5 Hz – 48,5 Hz	30 minutes
48,5 Hz – 49,0 Hz	30 minutes
49,0 Hz – 51,0 Hz	Unlimited
51,0 Hz – 51,5 Hz	30 minutes

Table 1 Minimum time periods to be capable of operating on different frequencies, deviating from a nominal value without disconnecting from the network.

For frequency range between 48.5Hz and 49.0Hz, transmission-connected demand facilities, transmission-connected distribution facilities and distribution systems shall be capable to remain connected to the TSO network and to operate for a minimum period of 30 minutes. This is the recommended value for all the Continental European Synchronous Area (CE SA) as per Connection Network Code Work Group (also the case for RfG NC).

Commented [A4]: In conflict with IEC-60601-1 standard for medical equipment 49 Hz - 51 Hz
With given ranges medical equipment might fail for emergency generation kicks in.

1.1.2. Extended frequency range [Art. 12 – 2]

The agreement on wider frequency ranges, longer times for operation is a site specific requirement that shall be agreed with transmission-connected demand facility or DSOs considering the system needs, their technically feasible frequency range and relative withstanding duration beyond the ones defined in paragraph 1.1.1.

1.2. General voltage requirements [Art. 13]

1.2.1. Voltage requirements in case of voltage level at the connection point between 110kV and 400kV [Art. 13 – 1]

The general voltage requirements are defined at the point of connection to the transmission grid, in line with Annex II of the NC DCC and presented in the table below:

- Voltage base is at or above 110 kV and up to (not including) 300 kV

Voltage range	Duration
0,90 pu – 1,118 pu	Unlimited
1,118 pu – 1,15 pu	20 minutes minimum

- Voltage base is from 300 kV to 400 kV (including)

Voltage range	Duration
0,90 pu – 1,05 pu	Unlimited
1,05 pu – 1,10 pu	20 minutes minimum

The following voltage base values are to be considered:

- 400kV
- 220kV
- 150kV
- 110kV

International studies ([9]) and experience ([7]) have proven the technical capabilities of high voltage equipment to fulfill these requirements concerning temporary overvoltage if the duration of the over voltage is limited to 20 minutes. Therefore the minimal duration of 20 minutes has been chosen by Elia. Nevertheless Elia believes that the temporary overvoltage withstand capabilities have to be in line with international standards (such as IEC 60071 and IEC 60038). For some voltage levels mentioned above this is not the case. Therefore Elia will only require the capabilities as demonstrated -through IEC type testing. It is however of great importance that protection system settings are in line with the above mentioned requirements. Concerning the rated voltages of high voltage equipment Elia applies IEC standards.

1.2.2. Automatic voltage disconnection [Art. 13 – 6]

There is no general need for automatic disconnection at specific voltages except for some individual connection projects. The terms and settings for automatic disconnection shall be agreed upon between the TSO and the transmission-connected demand facility owner or the (C)DSO.

1.2.3. Voltage requirements for transmission-connected (closed) distribution systems in case of a voltage level at the connection point below 110kV [Art. 13 – 7]

The voltage level at the connection point to the transmission system of (closed) distribution systems can be lower than 110kV in Belgium. More specifically, (closed) distribution systems can be connected at voltage levels of 70kV, 36kV, 30kV and lower.

For these voltage levels, following requirements are defined at the point of connection to the transmission grid :

Voltage range	Duration
0,90 pu – 1,118 pu	Unlimited

Commented [A5]: The voltage requirements should also respect EN 50160 as stipulated in article 44 of the Federal Grid Code.

The following voltage base values are to be considered:

- 6 kV
- 10 kV
- 11 kV
- 12 kV
- 15 kV
- 26 kV
- 30 kV
- 36 kV
- 70 kV

It has to be noticed that the requirement on the upper value of the voltage range does not replace the material voltage withstand capability which is required through Annex I of the Federal Grid Code.

1.3. Short-Circuit requirements [Art. 14]

1.3.1. Short-circuit withstand capability [Art. 14 – 1]

The maximum short-circuit current at the point of connection to the transmission grid that a transmission-connected demand facility or (closed) distribution system shall be capable of withstanding will be specified for each voltage level, and will be specified in the revised version of the Grid Code.

1.3.2. Communication of a change in maximum short-circuit current [Art. 14 – 3 , 14 – 5, 14 – 8, 14 – 9]

These articles are related to a specific situation/event. These articles present requirements that will be particularized for the cases indicated there.

In general no changes in short-circuit withstand capability are expected as they will be defined in a non-site specific manner.

1.4. Reactive Power Requirements [Art. 15]

1.4.1. Reactive power exchange between the transmission system and transmission-connected demand facilities [Art. 15 – 1 (a)]

A technical capability must be present in the transmission-connected demand facility to be able to keep the reactive power exchange at the connection point between the following limits:

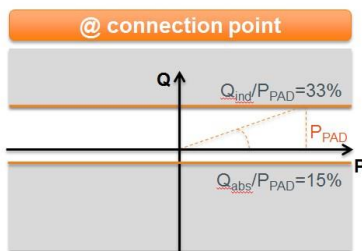
- For the import of reactive power (consumption) the limit is fixed to 33% of the maximum import or export capacity of the connected demand facility,
- For the the export of reactive power (production) the limit is fixed to 15% of the maximum import or export capacity of the connected demand facility.

Exceptions can be allowed for a specific connection point, but technical or financial benefits should be demonstrated before granting such an exception.

The Power Put At Disposal (PPAD) is fixed for the import and export of power from or to the transmission grid. These values are fixed in the connection contract. The above mentioned 'maximum import or export capacity' concerns the maximum of both PPAD values.

These requirements ensure that a sufficient amount of reactive power sources will be present in the transmission-connected demand facility but do not specify their usage (in operations).

So, without prejudice to other operational rules, these capabilities have to be demonstrated during the connection process for a limited number of predefined reference scenarios but do not exclude operation with reactive power exchanges outside the above-mentioned limits.



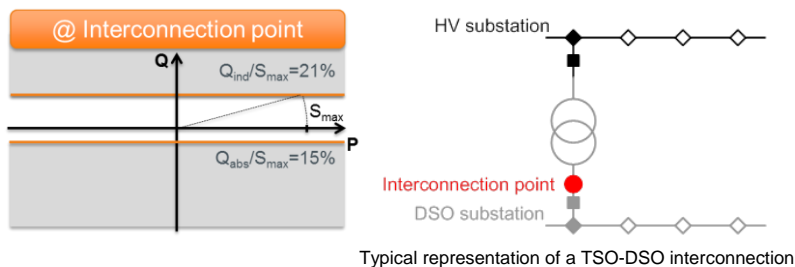
1.4.2. Reactive power exchange between the transmission system and transmission-connected (closed) distribution systems [Art. 15 -1 (b), Art. 15 – 1 (c)]

The Belgian transmission system or the (closed) distribution systems contain power transformers that transform voltage levels of 30kV and higher to voltage levels below 30kV. As the reactive losses in power transformers are not negligible (~12%¹ of the active power flow), the requirements on reactive power exchange between the transmission and (closed) distribution systems need to take this aspect into account.

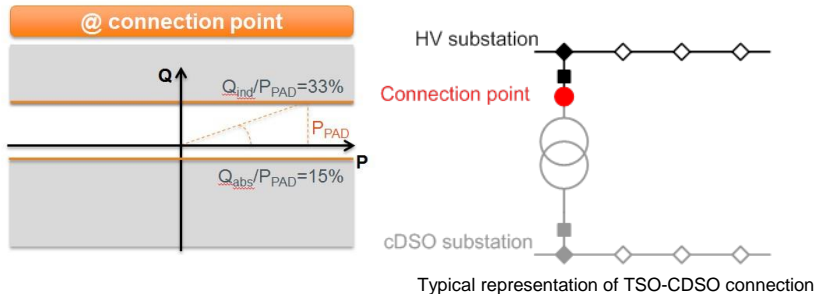
The import of reactive power (consumption) typically occurs at moments of high active power consumption. This also means that the reactive power losses in the power transformers are high in those situations. The export of reactive power typically occurs at moments of low active power exchange between the transmission and distribution system. Reactive power losses in the distribution power transformers are negligible in those situations.

A technical capability must be present in the connected (closed) distribution system (including capabilities of production unit connected to the (closed) distribution system) to be able to keep the reactive power exchange at the connection point between the following limits:

- For the import of reactive power (consumption) the limit is fixed to
 - 33% of the maximum import or export capacity of the connected (closed) distribution system if the voltage level at the connection point of the (closed) distribution system is equal or higher than 30kV.
 - 21% of the maximum import or export capacity of the connected (closed) distribution system if the voltage level at the connection point of the (closed) distribution system is lower than 30kV.
- For the export of reactive power (production) the limit is fixed to 15% of the maximum import or export capacity of the connected (closed) distribution system in both cases (not dependent of the voltage level at the connection point).



¹ The short-circuit voltage of distribution power transformers is 12% in average.



The maximum import or export capacity is equal to:

- the Power Put At Disposal (PPAD) in case of a transmission-connected closed distribution system. The PPAD is fixed for the import and export of power from or to the transmission grid. These values are fixed in the connection contract. The above mentioned 'maximum import or export capacity' concerns the maximum of both PPAD values;
- the Power Put At Disposal (PPAD) in case of distribution system (closed distribution system excluded) with a voltage level at the connection point equal or higher than 30kV. The PPAD is fixed for the import and export of power from or to the transmission grid. These values are fixed in the collaboration agreement. The above mentioned 'maximum import or export capacity' concerns the maximum of both PPAD values;
- the minimal available exchange capacity at the connection point when taking into account the contingencies on grid elements (N-1), i.e. $S_{nom, N-1}$ in case of distribution system (closed distribution system excluded) with a voltage level at the connection point lower than 30kV.

Exceptions can be allowed for a specific connection point or a set of connection points, but technical or financial benefits should be demonstrated through a joint analysis between Elia and the transmission-connected (closed) distribution system owner before granting such an exception as mentioned in [Art. 15 – 1 (c)].

In this perspective, in case of difficulty to reach the above mentioned requirements with the available assets within the (closed) distribution system (including capabilities of production unit connected to the (closed) distribution system) for a given (or a set of) connection point(s), a joint analysis between Elia and the transmission-connected (closed) distribution system owner will be conducted before an investment should be done. The goal of this joint analysis is to guarantee to reach the above-mentioned limits (either for each separate connection point or for a set of connection points of the (closed) distribution grid using the interconnection of the (distribution) grid) and to guarantee that, if an investment has to be done, it is the overall technical and economical optimum.

These requirements ensure that a sufficient amount of reactive power sources (including capabilities of production unit connected to the (closed) distribution system) will be present in the connected (closed) distribution system but do not specify anything about their usage (in operations).

So, without prejudice to other operational rules, these capabilities have to be demonstrated during the connection process for a limited number of predefined reference scenarios but do not exclude operation with reactive power exchanges outside the above-mentioned limits.

1.4.3. Reactive power exchange between the transmission system and transmission-connected (closed) distribution systems at low active power flow [Art. 15 – 2]

According to the Art 15.2 of NC DCC, the relevant TSO may require that transmission-connected (closed) distribution systems have the capability at the connection point to not export reactive power (at reference 1 pu voltage) at an active power flow of less than 25 % of the maximum import capability.

After analysis, Elia confirms that this requirement reflects a need for the global Belgium zone to be able to manage the reactive power flows and operate the system with the same quality of service in the future as it is nowadays taking into account the expected evolution of energy mix in Belgium.

In this context, a technical capability must be present in the connected (closed) distribution system (including capabilities of production unit connected to the (closed) distribution system) to be able to not export reactive power (at reference 1 pu voltage) at the connection point at an active power flow of less than 25% of the maximum import capacity.

The maximum import or export capacity is equal to:

- the Power Put At Disposal (PPAD) in case of a transmission-connected closed distribution system. The PPAD is fixed for the import and export of power from or to the transmission grid. These values are fixed in the connection contract. The above mentioned 'maximum import or export capacity' concerns the maximum of both PPAD values;
- the Power Put At Disposal (PPAD) in case of distribution system (closed distribution system excluded) with a voltage level at the connection point equal or higher than 30kV.
- the minimal available exchange capacity at the connection point when taking into account the contingencies on grid elements (N-1), i.e. $S_{nom, N-1}$ in case of distribution system (closed distribution system excluded) with a voltage level at the connection point lower than 30kV.

In case of difficulty to reach the above mentioned requirement with the available assets within the (closed) distribution system (including capabilities of production unit connected to the (closed) distribution system) for a given (or a set of) connection point(s), a joint analysis between Elia and the transmission-connected (closed) distribution system owner will be conducted before an investment should be done. The goal of this joint analysis is:

1. to verify whether the above mentioned requirement is justified (according to art 15.2 of the DCC NC) either for each separate connection point or for a set of connection points of the distribution grid
2. then (if this requirement is confirmed), to guarantee the capability to reach the above-mentioned limits (either for each separate connection point or for a set of connection points of the (closed) distribution grid using the interconnection of the (distribution) grid)

3. to guarantee that, if an investment has to be done, it is the overall technical and economical optimum. This implies that this investments shall be done at the most appropriate grid segment by the relevant System Operator, and it responds to the needs of the system at the lowest overall societal costs on a long term basis

Note that, accorded to art 15.2 of the DCC NC, if this requirement is not justified based on the joint analysis (see point 1 above), Elia and the transmission-connected (closed) distribution system operator will agree in the collaboration agreement on alternative requirements according to the outcomes of a joint analysis and based on the overall technical and economical optimum.

These requirements ensure that a sufficient amount of reactive power sources (including capabilities of production unit connected to the (closed) distribution system) will be present in the connected (closed) distribution system but do not specify anything about their usage (in operations).

So, without prejudice to other operational rules, these capabilities have to be demonstrated during the connection process for a limited number of predefined reference scenarios but do not exclude operation with reactive power exchanges outside the above-mentioned limits.

1.4.4. Metrics to express the reactive power capability ranges [Art. 15 – 1 (d)]

All limits are expressed as a percentage of the maximum import or export capacity. The power factor is not used.

1.5. Protection requirements [Art. 16]

1.5.1. Devices and settings required to protect the transmission system [Art. 16 – 1]

The protection schemes and settings relevant for the transmission-connected demand facility or the transmission-connected (closed) distribution system are to be determined and agreed site specific by the RTSO and the transmission-connected demand facility owner or (closed) distribution system operator.

Commented [A6]: Indien geen overeenkomst wordt bereikt, is dan de CREG bevoegd?

1.6. Control requirements [Art. 17]

1.6.1. Schemes and settings of different control devices [Art. 17 – 1]

The RTSO and the transmission-connected demand facility owner or the transmission connected (closed) distribution system operator shall agree on the schemes and settings of the different control devices relevant for system security of the transmission-connected demand facility or the transmission-connected distribution system.

Commented [A7]: Indien geen overeenkomst wordt bereikt, is dan de CREG bevoegd?

1.7. Information exchange [Art. 18]

1.7.1. Specifications of information exchange equipment [Art. 18 – 1, 18 – 2, 18 – 3]

For real-time information exchange between transmission-connected demand facilities and the TSO, or between transmission-connected (closed) distribution systems and the TSO, the TSO applies the TASE 2 (IEC 60870-6) and IEC104 IEC 60870-5-104 Transmission Protocol standards. These standards support time stamping. As standards can change over time Elia will make them publically on its website.

It is important to implement these protocols on a private transmission path (not through the public internet) for reliability and cybersecurity reasons.

Although the refresh rate is not mentioned in the NC DCC, real-time measurement is defined as a measurement (representation of the current state of a facility) that is refreshed at a rate faster than one minute ('elapsed time'). For data related to automatic load frequency control processes, it shall not be longer than 10 s. For other purposes, it shall be as fast as possible and, in any case, not slower than one minute. For information exchange between the TSO and a transmission-connected distribution system a hysteresis method can also be allowed. Further specifications of this method will be defined in the TSO-DSO agreements for transmission connected distribution systems.

Regarding voice communication the requirements concerning backup power supply and equipment redundancy are defined by article 41 of the Network Code Emergency & Restoration.

1.8. Demand disconnection and demand reconnection [Art. 19]

1.8.1. Low Frequency Demand Disconnection [Art. 19 – 1 (a), Art. 19 – 1 (b), Art. 19 – 1 (c)]

Elia as TSO will require transmission-connected distribution system operators to provide automatic low frequency demand disconnection capabilities. The Belgian transmission system contains the power transformers that transform voltage levels of 30kV and higher to voltage levels below 30kV. Therefore this requirement will only apply to a very limited number of cases.

Currently, the low frequency triggers will disconnect all the power transformers at the connection point (non-selective), resulting in a disconnection of the complete demand and production at the connection point. This is why the automatic frequency disconnection is currently not implemented in every case. In the near future an automatic demand disconnection in stages (selective) could be required. The settings of these automatisms will be communicated at the design phase of the connection, during the connection process.

Elia does not currently require transmission-connected demand facilities owners and transmission-connected closed distribution operators to provide automatic low frequency demand disconnection capabilities. Elia does however not exclude that this will be part of a future defense plan.

As mentioned in [8] the reliability, dependability and speed of a Low Frequency Demand Disconnection scheme are key to secure a power system in case of major disturbances. Several actions are typically covered within such a scheme:

- The operating time of the under-frequency relays (measurement, individual relay logic and relays combination logic)
- The time of tele protections in case of a transfer trip (in case the underfrequency load shedding relay has to trip a remote load)
- The interface relays (in case the underfrequency load shedding relay and the circuit breaker to trip belong to different entities)
- The time of operation of the circuit breaker.

The operating time of 150ms specified in [Art. 19 – 1(c)] should be interpreted as a maximum boundary for the frequency relay operating time. The specifications of the compliance testing of the frequency relay will be defined by Elia in accordance with article 37 of the DCC.

1.8.2. Low Voltage Demand Disconnection [Art. 19 – 2 (a), Art. 19 – 2(b)]

Elia as TSO will not require to the transmission-connected (closed) distribution system operators and transmission-connected demand facilities owners to provide low voltage disconnection capabilities. Elia does however not exclude that this will be part of a future defense plan.

1.8.3. Blocking of on load tap changers [Art. 19 – 3 (a), Art. 19 – 3 (b)]

Elia requires automatic on load tap changer block on transformers that supply distribution systems. The specifications of this automatism will be communicated to Elia before being installed, for example at the design phase of the connection process. The Belgian transmission system contains power transformers that transform voltage levels of 30kV and higher to voltage levels below 30kV. As a consequence the on load tap changer blocking will be installed by the TSO in many cases.

These requirements do not apply to transmission-connected closed distribution facilities. Elia does however not exclude that this will be part of a future defense plan.

1.8.4. Reconnection [Art. 19 – 4 (a), Art. 19 – 4 (b), Art. 19 – 4 (c)]

In general, the RTSO does not allow automatic reconnection, as a manual reconnection after clearance of the control center of Elia is preferred. In specific cases Elia could allow automatic reconnection. The latter will be fixed in connection contracts for transmission_connected demand facilities and closed distribution systems, and TSO-DSO agreements for transmission connected distribution systems.

The settings of synchronisation devices are site specific and to be agreed with transmission-connected demand facility owner or the transmission-connected (closed) distribution system operator.

In case of remote disconnection of a transmission-connected demand facility or (closed) distribution facility due to scarcity, Elia will in require to complete the disconnection within 10

minutes. This value will however be confirmed during the design phase of the connection, during the connection process.

1.9. Power quality [Art. 20]

The level of allowed distortion or fluctuation of the supply voltage on the network at the connection point of a transmission-connected demand facility or a transmission-connected (closed) distribution system will not alter from what is stated in article 46 of the current Federal Grid Code.

1.10. Simulation models [Art. 21]

1.10.1. Models or equivalent information showing the behavior in steady and dynamic states [Art. 21 – 2, 21 – 3]

Elia will not require the specific simulation models mentioned in the NC DCC showing the behavior of the transmission-connected demand facilities and transmission-connected (closed) distribution systems in steady and dynamic states.

Elia will however require specific data of transmission-connected demand facilities and transmission-connected closed distribution systems as defined during the connection process. The required data concerning transmission-connected distribution systems is defined by the TSO-DSO operation agreement.

1.10.2. Recordings to compare with model [Art. 21 – 5]

Elia will not require the specific recordings of the transmission-connected demand facilities and transmission-connected (closed) distribution systems as mentioned in the NC DCC, in order to compare the response of the model with these recordings.

2. Connection of demand units used by a demand facility or a closed distribution system to provide demand response services to system operators

2.1. Demand units providing active power control, reactive power control and transmission constraint management [Art. 28]

2.1.1. Definition of an extended frequency range [Art. 28 – 2 (a)]

The frequency requirements defined in section 1.1. are also applicable to demand units with demand response active power control, demand response reactive power control, or demand response transmission constraint management, or demand response system frequency control, either individually or, where it is not part of a transmission connected demand facility, collectively as part of demand aggregation through a third party.

2.1.2. Definition of voltage range if connected at a voltage below 110kV [Art. 28 – 2 (c)]

The normal operational voltage range at the connection point across which a demand unit delivering demand response shall be capable to operate will be fixed by Elia and the distribution system operators.

2.1.3. Time period to modify power consumption [Art. 28 – 2 (f)]

The time period within which a demand unit delivering demand response needs to adjust its power consumption depends on the type of offered demand response service. These time periods are defined in the terms and conditions (T&C) of these services. As they tend to evolve in time, fixed values cannot be given.

2.1.4. Notification of changes in demand response capacity [28 – 2 (i)]

The notification of a change in demand response capacity shall be carried-out as per the contractual provisions of the terms and conditions (T&C) of this service.

2.1.5. Technical specifications to enable transfer of information [Art. 28 – 2 (e), 28 – 2 (l)]

For active or reactive power control and transmission constraint management services, the technical communication requirements are defined as per the current contractual provisions.

2.1.6. Definition of the ROCOF maximum value [Art. 28 – 2 (k)]

The requirement for Rate of Change of Frequency (RoCoF) withstanding capability is aligned with the requirements for generators (RfG Article 13.1.(b)) which is defined in coordination with TSOs in the European Continental Synchronous area. The current applicable ENTSO-e IGD proposes a profile taking 2.0 Hz/s for duration of 500ms as the minimum RoCoF to be withstood as per the Figure 1.

Commented [A8]: In dit hoofdstuk staat geen enkele verwijzing naar een mogelijke vergoeding voor diens naar het neutraliseren van de impact op de BRP.

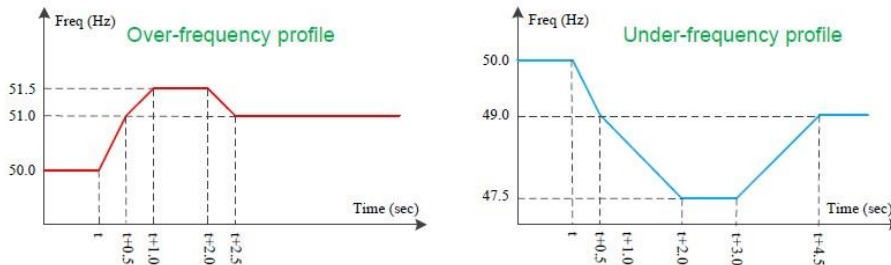


Figure 1 Overfrequency and underfrequency withstanding capabilities

2.2. Demand units with demand response system frequency control [Art. 29]

All frequency related technical requirements are coordinated with TSOs in the European Continental Synchronous area. The implementation of the Article 29 of the DCC NC is covering only the technical capabilities of LFSM-U and LFSM-O emergency functions whenever identified necessary and required by Elia. With respect to Frequency Containment (FCR) service, the relevant technical requirements are defined as per the general framework for FCR Service.

2.2.1. Definition of an extended frequency range [Art. 29 – 2 (a)]

This requirement is defined according to Art. 29(2)a of NC DCC. The frequency ranges and extended range, defined in section 1, are also applicable to demand units with demand response active power control, demand response reactive power control, demand response transmission constraint management, or demand response system frequency control, either individually or, where it is not part of a transmission connected demand facility, collectively as part of demand aggregation through a third party.

2.2.2. Definition of voltage range if connected at a voltage below 110kV [Art. 29 – 2 (c)]

The normal operational voltage range at the connection point at a voltage below 110kV across which a demand unit delivering demand response system frequency control shall be capable of operating, will be fixed by Elia and the distribution grid owners.

Commented [A9]: Artikel 29 verwijst eveneens naar een marktbevraging omtrent de mogelijkheden voor eenheden geconnecteerd lager dan 110kV.

2.2.3. Definition of allowed frequency dead band [Art. 29 – 2 (d)]

The current draft requirement is aligned with Entso-e IGD prescribing the allowed maximum frequency dead band for LFSM-U and LFSM-O emergency system frequency control as ± 200 mHz for the CE synchronous area. Therefore resulting in under-frequency threshold of 49.8 Hz and over-frequency threshold of 50.2 Hz.

Commented [A10]: Artikel 29 verwijst eveneens naar een marktbevraging omtrent de mogelijkheden voor eenheden geconnecteerd lager dan 110kV.

2.2.4. Maximum frequency deviation to respond [Art. 29 – 2 (e)]

The current draft requirement is aligned with Entso-e IGD recommending the maximum frequency deviation to respond for LFSM-U and LFSM-O emergency system frequency control respectively as – 49 Hz and 51.5 Hz for the CE synchronous area.

Commented [A11]: Artikel 29 verwijst eveneens naar een marktbevraging omtrent de mogelijkheden voor eenheden geconnecteerd lager dan 110kv.

2.2.5. Definition of the rapid detection and response to frequency system changes [Art. 29 – 2 (g)]

The current draft requirement proposes the following parameters for the rapid detection and response in case of LFSM-U and LFSM-O is defined as following:

- Maximum time delay (rapid detection): 400 ms (this includes provision frequency measurement update i.e. 200 ms, breaker operating time, controller time delay);
- Linear proportional response: this shall be achieved following a DR SFC droop:

$S_{DR\ SFC} = \left(\frac{\Delta f}{f_n}\right) / \left(\frac{-\Delta P_{DR}}{P_{ref}}\right)$. The equivalent droop should be adjustable to equivalent droop between 2% and 12%.

Commented [A12]: Zal dit niet eerder trapsgewijs verlopen, aangezien klanten apparaten zullen afschakelen (aan of uit)

2.3. Demand units with demand response very fast active power control [Art. 30]

There are no minimum requirement for inertia contribution, this will not be considered necessary as of today ~~within the synchronous area~~.

REFERENCES

[1] 'Network Code on Demand Connection' or 'NC DCC': Commission Regulation (EU) 2016/1388 of 17 August 2016 establishing a Network Code on Demand Connection, <http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32016R1388&from=EN>

[2] 'Network Code Requirements for Generators' or 'NC RfG': Commission Regulation (EU) 2016/631 of 14 April 2016 establishing a network code on requirements for grid connection of generators, <http://eur-lex.europa.eu/legalcontent/EN/TXT/PDF/?uri=CELEX:32016R0631&from=EN>

[3] 'Network Code on High Voltage Direct Current' or 'NC HVDC': Commission Regulation (EU) 2016/1447 of 26 August 2016 establishing a network code on requirements for grid connection of high voltage direct current systems and direct current-connected power park modules, <http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32016R1447&from=EN>.

[4] Federal Technical Reglement- 19 DECEMBER 2002. — Koninklijk besluit houdende een technisch reglement voor het beheer van het transmissienet van elektriciteit en de toegang ertoe, Arrêté royal établissant un règlement technique pour la gestion du réseau de transport de l'électricité et l'accès à celui-ci, <http://www.elia.be/~media/files/Elia/publications-2/gridcodes/Technisch%20reglement%20Federaal%202002.pdf>.

[5] Presentation FOD/SPF Energy in WG Belgian Grid (in Dutch): <http://www.elia.be/~media/files/Elia/users->

Formatted: French (Belgium)

Formatted: French (Belgium)

Field Code Changed

Field Code Changed

Formatted: French (Belgium)

Field Code Changed

Formatted: French (Belgium)

Field Code Changed

Formatted: French (Belgium)

Field Code Changed

Formatted: French (Belgium)

Formatted: French (Belgium)

Field Code Changed

Formatted: French (Belgium)

Formatted: French (Belgium)

Field Code Changed

Field Code Changed

[group/WG%20Belgian%20Grid/20170307%20WG%20Belgian%20Grid/FOD_Visionfor_FederalGridCode.pdf](#)

- [6] ENTSO-E Guidance document for national implementation for network codes on grid connection: Parameters of Non-exhaustive requirements, 16 November 2016:
https://www.entsoe.eu/Documents/Network%20codes%20documents/NC%20RfG/161116_IGD_General%20guidance%20on%20parameters_for%20publication.pdf
- [7] ENTSO-E Guidance document for national implementation for network codes on grid connection: Parameters related to voltage issues, 16 November 2016:
https://www.entsoe.eu/Documents/Network%20codes%20documents/NC%20RfG/161116_IGD_Parameters%20related%20to%20voltage%20issues_for%20publication.pdf
- [8] ENTSO-E Internal Guidance for national implementation of network codes on grid connection : FREQUENTLY ASKED QUESTIONS - FAQ 1 - *What is the goal of the requirement on operating time of the LFDD schemes in the NC DCC? How should Article 19.1.c.(2) be understood?*
- [9] CIGRE: WG 33.10, Temporary Overvoltages: Withstand Characteristics of Extra High Voltage Equipment, Electra No.179 August 1998, pp. 39-45

APPENDIX – LIST OF NON-EXHAUSTIVE REQUIREMENTS FOR NC DCC

This list is extracted from ENTSO-E Guidance document for national implementation for network codes on grid connection : Parameters of Non-exhaustive requirements [6]



PROPOSAL FOR NC HVDC REQUIREMENTS OF GENERAL APPLICATION

TABLE OF CONTENTS

Introduction	66
1. Scope of application.....	88
2. TITLE II: General Requirements for HVDC connections	99
2.1. Chapter 1: Requirements for active power control and frequency support	99
2.1.1. Article 11: Frequency ranges.....	99
2.1.1.1. Frequency Ranges §11.1	99
2.1.1.2. Wider frequency Ranges §11.2.....	99
2.1.1.3. Automatic disconnection §11.3	99
2.1.1.4. Maximum admissible power output §11.4	99
2.1.2. Article 13: Active power controllability, control range and ramping rate	99
2.1.2.1. Active power controllability §13.1(a)i	99
2.1.2.2. Active power controllability §13.1(a)ii	99
2.1.2.3. Active power controllability §13.1(a)iii	1040
2.1.2.4. Active power controllability §13.1(b).....	1040
2.1.2.5. Fast active power reversal §13.1(c)	1040
2.1.2.6. Automatic remedial actions §13.3.....	1040
2.1.3. Article 14: Synthetic inertia	1040
2.1.3.1. Synthetic inertia §14.1	1040
2.1.3.2. Synthetic inertia §14.2.....	1040
2.1.4. Annex II: Requirements applying to frequency sensitive mode, limited frequency sensitive mode overfrequency and limited frequency sensitive mode underfrequency ..	1040
2.1.4.1. Frequency Sensitive mode Annex II A1(a)	1144
2.1.4.2. Frequency Sensitive mode Annex II A1(d)(ii)	1144
2.1.4.3. LFSM-O Annex II B1(c)	1144
2.1.4.4. LFSM-O Annex II B2	1144
2.1.4.5. LFSM-U Annex II C1(c)	1144
2.1.4.6. LFSM-U Annex II C2	1144
2.1.5. Article 16: Frequency control.....	1144
2.1.5.1. Frequency control mode §16.1	1144
2.1.5.2. Frequency control mode §16.2	1144
2.1.6. Article 17: Maximum loss of active power	1144
2.1.6.1. Maximum loss of active power §17.1	1144
2.2. Chapter 2: Requirements for reactive power control and voltage support	1242
2.2.1. Article 18: Voltage ranges.....	1242
2.2.1.1. Voltage ranges Annex III Table 4	1242
2.2.1.2. Voltage ranges Annex III Table 5.....	1242
2.2.1.3. Agreement on wider voltage ranges or longer minimum times §18.2	1242
2.2.1.4. Automatic disconnection §18.3	1242
2.2.1.5. Voltage ranges §18.4	1242
2.2.2. Article 19: Short circuit contribution during faults.....	1242
2.2.2.1. Short circuit contribution during faults §19.2(a)	1242
2.2.2.2. Short circuit contribution during faults §19.2(b)	1242
2.2.2.3. Short circuit contribution during faults §19.2(c).....	1243

2.2.2.4. Short circuit contribution during faults §19.3.....	1343
2.2.3. Article 20: Reactive power capability.....	1343
2.2.3.1. Reactive power capability §20.1.....	1343
2.2.3.2. Reactive power capability §20.3.....	1343
2.2.4. Article 21: Reactive power exchanged with the network.....	1343
2.2.4.1. Reactive power exchanged with the network §21.2.....	1343
2.2.5. Article 22: Reactive power control mode.....	1343
2.2.5.1. Reactive power control mode §22.1.....	1343
2.2.5.2. Reactive power control mode §22.2.....	1343
2.2.5.3. Reactive power control mode §22.3(b).....	1343
2.2.5.4. Reactive power control mode §22.3(c)(i).....	1344
2.2.5.5. Reactive power control mode §22.3(c)(ii).....	1444
2.2.5.6. Reactive power control mode §22.3(d).....	1444
2.2.5.7. Reactive power control mode §22.4.....	1444
2.2.5.8. Reactive power control mode §22.5.....	1444
2.2.5.9. Reactive power control mode §22.6.....	1444
2.2.6. Article 23: Priority to active or reactive power contribution.....	1444
2.2.6.1. Priority to active or reactive power contribution §23.....	1444
2.2.7. Article 24: Power Quality.....	1444
2.2.7.1. Power quality §24.....	1444
2.3. Chapter 3: Requirements for fault ride through capability.....	1444
2.3.1. Article 25: Fault ride through capability.....	1444
2.3.1.1. Fault ride through capability §25.1.....	1444
2.3.1.2. Fault ride through capability §25.2.....	1545
2.3.1.3. Fault ride through capability §25.4.....	1545
2.3.1.4. Fault ride through capability §25.5.....	1545
2.3.1.5. Fault ride through capability §25.6.....	1545
2.3.2. Article 26: Post fault active power recovery.....	1545
2.3.2.1. Post fault active power recovery §26.....	1545
2.4. Chapter 4: Requirements for control.....	1546
2.4.1. Article 28: Energisation and synchronisation of HVDC converter stations.....	1546
2.4.1.1. Energisation and synchronisation of HVDC converter stations §28.....	1546
2.4.2. Article 29: Interaction between HVDC systems or other plants and equipment.....	1646
2.4.2.1. Interaction between HVDC systems or other plants and equipment §29.2.....	1646
2.4.2.2. Interaction between HVDC systems or other plants and equipment §29.7.....	1646
2.4.3. Article 30: Power oscillation damping capability.....	1646
2.4.3.1. Power oscillation damping capability §30.....	1646
2.4.4. Article 31: Subsynchronous torsional interaction damping capability.....	1646
2.4.4.1. Subsynchronous torsional interaction damping capability §31.2.....	1646
2.4.4.2. Subsynchronous torsional interaction damping capability §31.3.....	1646
2.4.5. Article 32: Network characteristics.....	1646
2.4.5.1. Network characteristics §32.1.....	1646
2.4.6. Article 33: HVDC system robustness.....	1647
2.4.6.1. HVDC system robustness §33.1.....	1647
2.4.6.2. Network characteristics §33.2.....	1647
2.5. Chapter 5: Requirements for protection devices and settings.....	1747
2.5.1. Article 34: Electrical protection schemes and settings.....	1747
2.5.1.1. Electrical protection schemes and settings §34.1.....	1747
2.5.1.2. Electrical protection schemes and settings §34.3.....	1747
2.5.2. Article 35: Priority ranking of protection and control.....	1747
2.5.2.1. Priority ranking of protection and control §35.1.....	1747
2.5.2.2. Priority ranking of protection and control §35.2.....	1747
2.5.3. Article 36: Changes to protection and control schemes and settings.....	1748
2.5.3.1. Changes to protection and control schemes and settings §36.1.....	1748

2.5.3.2. Changes to protection and control schemes and settings §36.2	1748
2.5.3.3. Changes to protection and control schemes and settings §36.3	1848
2.6. Chapter 6: Requirements for power system restoration	1848
2.6.1. Article 37: Black start	1848
2.6.1.1. Black start §37.1	1848
2.6.1.2. Black start §37.2	1848
2.6.1.3. Black start §37.3	1848
3. TITLE III: Requirements for DC-connected power park modules and remote-end HVDC converter stations	1849
3.1. Chapter 1: Requirements for DC-connected power park modules	1849
3.1.1. Article 39: Frequency stability requirements	1849
3.1.1.1. Frequency stability requirements §39.1	1849
3.1.1.2. Frequency ranges §39.2(a)	1849
3.1.1.3. Wider frequency ranges §39.2(b)	1849
3.1.1.4. Automatic disconnection §39.2(c)	1949
3.1.1.5. LFSM-O §39.4	1949
3.1.1.6. Constant power §39.5	1949
3.1.1.7. Active power controllability §39.6	1949
3.1.1.8. LFSM-U §39.7	1949
3.1.1.9. FSM with subject to a fast signal response §39.8	1949
3.1.1.10. Frequency restoration §39.9	1949
3.1.1.11. Frequencies other than 50Hz §39.10	1920
3.1.2. Article 40: Reactive power and voltage requirements	1920
3.1.2.1. Voltage ranges Annex VII Table 9 and 10	1920
3.1.2.2. Agreement on wider voltage ranges or longer minimum times §40.1(b)	1920
3.1.2.3. Automatic disconnection §40.1(c)	1920
3.1.2.4. Voltage ranges for other AC voltages §40.1(d)	1920
3.1.2.5. Agreement how to meet reactive power requirements §40.1(e)	1920
3.1.2.6. Reactive power capability §40.2(b)(i)	1920
3.1.2.7. Reactive power capability §40.2(b)(ii)	2020
3.1.2.8. Priority to active and reactive power contribution §40.3	2020
3.1.3. Article 41: Control requirements	2020
3.1.3.1. Synchronisation §41.1	2020
3.1.3.2. Output signals §41.2	2020
3.1.4. Article 42: Network characteristics	2024
3.1.4.1. Method of pre-fault and post-fault conditions §42(a)	2024
3.1.4.2. Equivalentents representing the collection grid §42(c)	2024
3.1.5. Article 43: Protection requirements	2024
3.1.5.1. Electrical protection schemes §43.1	2024
3.1.6. Article 44: Power quality	2024
3.1.6.1. Power quality §44	2024
3.2. Chapter 2: Requirements for remote-end HVDC converter stations	2024
3.2.1. Article 47: Frequency stability requirements	2024
3.2.1.1. Frequency ranges §47.1	2024
3.2.1.2. Frequency ranges §47.2	2124
3.2.2. Article 48: Reactive power and voltage requirements	2124
3.2.2.1. Reactive power and voltage ranges Annex VIII Table 12 and 13	2124
3.2.2.2. Agreement on wider voltage ranges or longer minimum times §48.1(b)	2124
3.2.2.3. Voltage ranges for other AC voltages §48.1(c)	2124
3.2.2.4. Reactive power provision §48.2(a)	2124
3.2.2.5. U-Q/Pmax – profile §48.2(a)	2122
3.2.3. Article 50: Power quality	2122
3.2.3.1. Power quality §50	2122

4. TITLE IV: Information Exchange and Coordination	2223
4.1.1. Article 51: Operation of HVDC systems	22 23
4.1.1.1. Operation of HVDC systems §51.1	22 23
4.1.1.2. Operation of HVDC systems §51.4	22 23
4.1.2. Article 52: Parameters and settings	22 23
4.1.3. Article 53: Fault recording and monitoring.....	22 23
4.1.3.1. Fault recording and monitoring §53.2 to 53.5	22 23
4.1.4. Article 54: Simulation models	22 23
4.1.4.1. Simulation models §54.1	22 23
5. References	2224
6. Appendix - List of non-exhaustive articles for HVDC.....	2325

INTRODUCTION

Scope of this document

Article 5(4) of the NC HVDC [1] states that the relevant system operator or TSO submits a proposal for requirements of general application (or the methodology used to calculate or establish them), for approval by the competent entity, within two years of entry into force of the NC HVDC, i.e. 28 September 2018. A similar requirement is included in the two other connection Network Codes, namely in Art. 7(4) of the NC RfG [2] and in Art. 6(4) of the NC DCC [3].

The aim of this document is to synthesize the technical proposal of the TSO regarding the Belgian implementation of the non-exhaustive requirements stated in the NC HVDC. This document is the final version of the proposal for requirements of general application (hereafter named as 'general requirements'), in accordance with Art. 5(4) of the NC HVDC.

On 17 May 2018, Elia will submit the general requirements proposals for NC RfG, but also for NC DCC and NC HVDC to the competent authority (because this is the deadline for the submission of the general requirements NC RfG and the decision has been taken to submit the general requirements for the three codes together) together with the (track change) proposal of an amended Federal Grid Code [4] (and a formal proposal on maximum capacity thresholds of type B, C and D power-generating modules (PGM)). Elia will organize beforehand a public consultation for all deliverables in March-April 2018 (except for the public consultation on the maximum capacity thresholds B, C and D, that already took place from 19 May till 20 June 2017). This approach is in line with the vision of the Belgian Federal Administration (FOD/SPF Energy) [5].

This document should be considered as a technical and not legally binding document, focusing on the clarification of various technical general requirements that will be reflected in various grid codes, contract, terms and conditions, regulatory documents and or technical prescriptions.

The document follows the same logic as in the NC HVDC: the proposal is organized per technical topic and per category. As such the NC HVDC provides for requirements for HVDC connections and for DC-connected power park modules and remote-end HVDC converter stations.

The scope of this document contains especially, but is not limited to, the implementation proposal of the non-exhaustive requirements in the NC HVDC. To increase its readability, this document might also contain NC exhaustive requirements, implementation proposal of non-exhaustive requirements of the other connection NC, or other specific national/regional requirements for information purposes only, but certainly does not cover all of them. Furthermore, some non-exhaustive requirements foreseen in the HVDC NC are sitespecific (and not general). A reference to those site-specific requirements is also included in this document. Some site-specific requirements require an agreement between the relevant system operator, the TSO and the owner of the unit in question. In such case, Article 5(5) of the NC HVDC shall apply, which foresees that the relevant parties shall then endeavor to seek an agreement within six months after a first proposal has been submitted by one party

to the other parties. Site-specific requirements might, e.g., be taken up in a connection agreement.

For which regards the complete list of non-exhaustive requirements to be proposed as general requirements, Elia is taking as reference the ENTSO-e guidance document on 'Parameter of Non-exhaustive requirements' [6]. This document does not only mention the parameters to be defined per topic, but also sometimes which article of each connection NC should be considered as non-exhaustive and who should be seen as relevant system operator to define an implementation proposal. In theory, both the TSO and (C)DSOs can be considered as 'relevant system operator', depending on the requirement. In practice, however, HVDC systems will in Belgium currently be connected to the TSO-grid. Hence, when a reference is made in this document (or in the NC HVDC) to the relevant system operator, this will in the current situation be the TSO, i.e. Elia.

Current HVDC knowledge and translation of this knowledge in general or sitespecific requirements

The current HVDC knowledge is limited:

- HVDC VSC converters: still experimental (limited European operational experience);
- Not yet any operational experience in Elia (NEMO: start foreseen in 2019);
- Academic & industrial research on DC-AC interactions still in early stages;
- Current proposals may not exclude future opportunities;
- International tendency to specify the least possible and gather experience.

This explains why the NC HVDC foresees a lot of site-specific requirements.

1. Scope of application

For the scope of application of the requirements of this document, please refer to Article 3 of the NC HVDC.

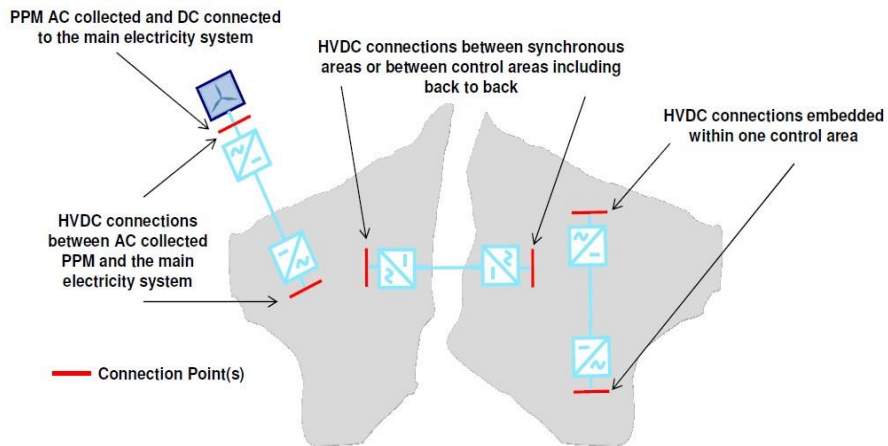


Figure 1 – The different HVDC applications as defined within the scope of application.

2. TITLE II: General Requirements for HVDC connections

2.1. Chapter 1: Requirements for active power control and frequency support

2.1.1. Article 11: Frequency ranges

2.1.1.1. Frequency Ranges §11.1

An HVDC system shall be capable of staying connected to the network and remaining operable within the following frequency ranges and time periods

- In the range from 47.0 Hz to 47.5 Hz for 60 seconds
- In the range from 47.5 Hz to 48.5 Hz for unlimited time
- In the range from 48.5 Hz to 49.0 Hz for unlimited time
- In the range from 49.0 Hz to 51.0 Hz for unlimited time
- In the range from 51.0 Hz to 51.5 Hz for unlimited time
- In the range from 51.5 Hz to 52.0 Hz for 30 minutes

2.1.1.2. Wider frequency Ranges §11.2

The definition of wider frequency ranges and longer minimum times for operation is site specific. It may be agreed between the TSO and HVDC system owner on a case by case basis.

2.1.1.3. Automatic disconnection §11.3

This requirement is site specific. It is to be specified by the TSO on a case by case basis.

2.1.1.4. Maximum admissible power output §11.4

In case of technical limitation, when operating at an AC system frequency below 49 Hz, the maximum admissible active power output reduction from its operating point shall not go beyond 2%/Hz.

2.1.2. Article 13: Active power controllability, control range and ramping rate

2.1.2.1. Active power controllability §13.1(a)i

The definition of a maximum and minimum power step size for adjusting the transmitted active power is site specific. It may be specified by the TSO on case by case basis.

2.1.2.2. Active power controllability §13.1(a)ii

The definition of a minimum active power transmission capacity for each direction, below which active power transmission capability is not requested, is site specific. It may be specified by the TSO on case by case basis.

Commented [A1]: The imposed durations are more stringent than the durations foreseen in the NC HVD

2.1.2.3. Active power controllability §13.1(a)iii

The definition of the maximum delay within which the HVDC system shall be capable of adjusting the transmitted active power is site specific. It is to be specified by the TSO on case by case basis.

2.1.2.4. Active power controllability §13.1(b)

The modalities according to which an HVDC system shall be capable of modifying the transmitted active power in case of disturbances into one or more of the AC networks to which it is connected is site specific and shall be specified by the TSO on a case by case basis. If the initial delay prior to the start of the change is greater than 10 milliseconds from receiving the triggering signal sent by the relevant TSO, it shall be reasonably justified by the HVDC system owner to the relevant TSO.

2.1.2.5. Fast active power reversal §13.1(c)

HVDC systems shall be capable of fast active power reversal. Fast active power reversal shall be performed as fast as technically feasible but in less than 2 seconds.

Commented [A2]: Is this feasible, for the converter well as for the grid?

2.1.2.6. Automatic remedial actions §13.3

The control functions of an HVDC system shall be capable of taking automatic remedial actions including, but not limited to, stopping the ramping and blocking FSM, LFSM-O, FFSM-U and frequency control.

Contingencies involving loss of generation or load may require Emergency Power Control (EPC), i.e. an automatic reduction or increase in the power transfer including possible power reversal. The System Owner shall design and supply a run-back (active power ramp-down) & run-up (active power ramp-up) control system that shall be able to activate in each station up to 10 distinct pre-programmed run-back cases and up to 10 run-up cases by external signals and each with a predefined setting for active power exchange [MW] and power ramp rate [MW/s] for the power setpoint change from the actual setting to the requested one. The Relevant System Operator or the Transmission System Operator must be able to trigger any of the 10 run-up and 10 run-back systems at any given instant.

The triggering and blocking criteria are site specific and shall be specified by the TSO on a case by case basis after notification to the CREG.

2.1.3. Article 14: Synthetic inertia

2.1.3.1. Synthetic inertia §14.1

This requirement is site specific. It is to be specified by the TSO on a case by case basis.

2.1.3.2. Synthetic inertia §14.2

This requirement is site specific. It is to be specified by the TSO on a case by case basis.

2.1.4. Annex II: Requirements applying to frequency sensitive mode, limited frequency sensitive mode overfrequency and limited frequency sensitive mode underfrequency

2.1.4.1. Frequency Sensitive mode Annex II A1(a)

This requirement is site specific. It is to be specified by the TSO on a case by case basis after notification to the CREG.

Commented [A3]: Notification or approval?

2.1.4.2. Frequency Sensitive mode Annex II A1(d)(ii)

This requirement is site specific. It is to be specified by the TSO on a case by case basis after notification to the CREG.

2.1.4.3. LFSM-O Annex II B1(c)

With regard to limited frequency sensitive mode - overfrequency (LSM-O), the HVDC system shall be capable of adjusting active power frequency response as fast as inherently technically feasible, with an initial delay as short as possible and time for full activation set at 2 seconds. This is subject to a notification to the CREG.

Formatted: Italian (Italy)

2.1.4.4. LFSM-O Annex II B2

The frequency threshold referred to in point (a) of paragraph 1 shall be adjustable between 50.2 Hz and 50.5 Hz and the minimum droop setting is 0.1% (the exact value will be set in connection contract). This is subject to a notification to the CREG.

2.1.4.5. LFSM-U Annex II C1(c)

The initial delay is the shortest time within technical feasible limits and with a possibility to implement an additional adjustable delay to be at full activation at 2 seconds. This is subject to a notification to the CREG.

2.1.4.6. LFSM-U Annex II C2

The frequency threshold referred to in point (a) of paragraph 1 shall be adjustable between 49.8 Hz and 49.5Hz and the minimum droop setting is 0.1% (the exact value will be set in connection contract). This is subject to a notification to the CREG.

2.1.5. Article 16: Frequency control

2.1.5.1. Frequency control mode §16.1

This is a site-specific requirement and can be specified by the TSO on a case by case basis.

2.1.5.2. Frequency control mode §16.2

The operating principle, the associated performance parameters and the activation criteria of this frequency control are site specific and shall be specified by the TSO on a case by case basis.

2.1.6. Article 17: Maximum loss of active power

2.1.6.1. Maximum loss of active power §17.1

This is a site-specific requirement and can be specified by the TSO on a case by case basis.

2.2. Chapter 2: Requirements for reactive power control and voltage support

2.2.1. Article 18: Voltage ranges

Formatted: French (Belgium)

2.2.1.1. Voltage ranges Annex III Table 4

HVDC systems connected between 110kV and 300kV shall remain connected for voltages between 1.118 pu – 1.15 pu for at least 10 hours.

Commented [A4]: 1 pu is not specified

2.2.1.2. Voltage ranges Annex III Table 5

HVDC systems connected between 300kV and 400kV shall remain connected for voltages between 1.05 pu – 1.0875 pu for at least 10 hours.

2.2.1.3. Agreement on wider voltage ranges or longer minimum times §18.2

The definition of wider voltage ranges and longer minimum times for operation is site specific. It may be agreed between RSO/TSO and HVDC system owner on a case by case level.

2.2.1.4. Automatic disconnection §18.3

The minimum requirement to stay connected is stated in the following table (stricter requirements may be specified on a case by case basis):

Time [ms]	Voltage amplitude [pu]
T<0 ms	1.0
0	0
250	0 (linearly rising to next point)
3000	0.9
∞	0.9

Commented [A5]: Two values at 0.9 pu : 3 sec and always

2.2.1.5. Voltage ranges §18.4

For connection points on voltages outside the range of 110 – 400kV, the same requirements as for 400kV connection points are taken.

Commented [A6]: What with 2.2.1.3, there it is mentioned case specific.

2.2.2. Article 19: Short circuit contribution during faults

2.2.2.1. Short circuit contribution during faults §19.2(a)

This requirement is site specific. It is to be specified by the RSO/TSO on a case by case basis.

2.2.2.2. Short circuit contribution during faults §19.2(b)

This requirement is site specific. It is to be specified by the RSO/TSO on a case by case basis.

2.2.2.3. Short circuit contribution during faults §19.2(c)

This requirement is site specific. It is to be specified by the RSO/TSO on a case by case basis.

2.2.2.4. Short circuit contribution during faults §19.3

This requirement is site specific. It is to be specified by the RSO/TSO on a case by case basis.

2.2.3. Article 20: Reactive power capability

2.2.3.1. Reactive power capability §20.1

This requirement is site specific. It is to be specified by the RSO/TSO on a case by case basis.

2.2.3.2. Reactive power capability §20.3

An HVDC system shall be capable of moving to any operating point within its U-Q/Pmax profile in less than 100 ms.

2.2.4. Article 21: Reactive power exchanged with the network

2.2.4.1. Reactive power exchanged with the network §21.2

This requirement is site specific. It is to be specified by the RSO/TSO on a case by case basis.

2.2.5. Article 22: Reactive power control mode

2.2.5.1. Reactive power control mode §22.1

An HVDC converter station shall be capable of operating in the following reactive power control modes:

- (a) voltage control mode; (b) reactive power control mode; (c) power factor control mode.

2.2.5.2. Reactive power control mode §22.2

An HVDC converter station shall be capable of operating in the following additional control modes:

- (a) voltage dependent reactive power control mode. The characteristics of this mode are subject of a mutual agreement between the relevant TSO and the HVDC system owner.
- (b) STATCOM mode: all previously specified control modes must be available without exchange of active power in the situation with or without the connection of the DC cable or overhead line.

2.2.5.3. Reactive power control mode §22.3(b)

The set point deadband shall be adjustable in steps of 0.5%

2.2.5.4. Reactive power control mode §22.3(c)(i)

In voltage control mode following a voltage step change, an HVDC system is able to achieve 90% of the change of reactive power within maximum 100ms with disabled ramp rate limiter.

2.2.5.5. Reactive power control mode §22.3(c)(ii)

The HVDC system shall be equipped with a reactive power ramp rate limiter with [settle-sets](#) the controlled AC voltage within the range of 99% of the setpoint in a programmable time span ranging between 1s and 60s with steps of 0.1s.

2.2.5.6. Reactive power control mode §22.3(d)

The slope of the instructed reactive power component shall be online adjustable in the range of 1 to 50 Mvar/s in steps of 0.1 Mvar/s.

2.2.5.7. Reactive power control mode §22.4

This requirement is site specific. It is to be specified by the RSO/TSO on a case by case basis.

2.2.5.8. Reactive power control mode §22.5

The maximum step size for reactive power is less than 1Mvar and for the voltage less than 1kV.

2.2.5.9. Reactive power control mode §22.6

This requirement is site specific. It is to be specified by the RSO/TSO on a case by case basis.

2.2.6. Article 23: Priority to active or reactive power contribution

2.2.6.1. Priority to active or reactive power contribution §23

Reactive power contribution shall have priority during low or high voltage operation and during faults for which fault-ride-through capability is required, taking into account the capabilities of the HVDC system specified.

2.2.7. Article 24: Power Quality

2.2.7.1. Power quality §24

This non-exhaustive requirement related to power quality will be based on the relevant [Synergrid regulations](#) regarding power quality, unless more stringent requirements are set forth in the connection contract.

Commented [A7]: We do not see the relation with Synergrid. Why not IEC?

2.3. Chapter 3: Requirements for fault ride through capability

2.3.1. Article 25: Fault ride through capability

2.3.1.1. Fault ride through capability §25.1

This requirement is site specific. It is to be specified by the RSO/TSO on a case by case basis. The terms and settings for automatic disconnection shall be agreed between RSO/TSO and HVDC system owner on a case by case basis.

The minimum requirement to stay connected is stated in the following table:

Time [ms]	Voltage amplitude [pu]
T<0 ms	1.0

0	0
250	0 (linearly rising to next point)
3000	0.9
∞	0.9

Commented [A8]: Two values at 0.9 pu : 3 sec and always

2.3.1.2. Fault ride through capability §25.2

TSO shall only provide this if requested by HVDC system owner

2.3.1.3. Fault ride through capability §25.4

Time is to be agreed between TSO and HVDC system owner, but TSO specifies the voltage levels on a case by case basis.

2.3.1.4. Fault ride through capability §25.5

This requirement is subject of an agreement between the system owner and the RSO/TSO on a case by case basis.

2.3.1.5. Fault ride through capability §25.6

The fault-ride through capabilities for asymmetrical faults of an HVDC system shall be the following

- (a) The HVDC converter station shall be able to inject negative sequence currents. There shall be separate positive and negative sequence current controllers.
- (b) It shall be possible to continue active power injection up to the maximum possible value.
- (c) No second harmonic current shall be transferred to the converters' DC side
- (d) Automatic reclosure of AC overhead lines may not lead to the disconnection of the HVDC system.

2.3.2. Article 26: Post fault active power recovery

2.3.2.1. Post fault active power recovery §26

A HVDC system shall be able to recover active power transmission following fault clearance and reach the pre-fault set-points within maximum 200ms. The relevant TSO may set the recovery time and post-fault ramping rate in order to reach a slower recovery.

2.4. Chapter 4: Requirements for control

2.4.1. Article 28: Energisation and synchronisation of HVDC converter stations

2.4.1.1. Energisation and synchronisation of HVDC converter stations §28

During the energisation or synchronisation of an HVDC converter station to the AC network or during the connection of an energised HVDC converter station to an HVDC system, the HVDC converter station shall have the capability to limit any voltage changes to a steady-state level. That steady-state level and the maximum magnitude, duration and measurement

window of the voltage transients are site specific and are to be specified by the RSO/TSO on a case by case basis. The steady-state level shall not exceed 5 per cent of the pre-synchronisation voltage.

2.4.2. Article 29: Interaction between HVDC systems or other plants and equipment

2.4.2.1. Interaction between HVDC systems or other plants and equipment §29.2

This requirement is site-specific and is to be specified by the RSO/TSO on a case by case basis.

2.4.2.2. Interaction between HVDC systems or other plants and equipment §29.7

This requirement is site-specific and is to be specified by the RSO/TSO on a case by case basis.

2.4.3. Article 30: Power oscillation damping capability

2.4.3.1. Power oscillation damping capability §30

This requirement is site specific. It has to be agreed between the TSO and the HVDC system owner on a case by case basis.

2.4.4. Article 31: Subsynchronous torsional interaction damping capability

2.4.4.1. Subsynchronous torsional interaction damping capability §31.2

This requirement is site specific and needs to be specified by the TSO on a case by case basis.

2.4.4.2. Subsynchronous torsional interaction damping capability §31.3

This requirement is site specific and needs to be specified by the TSO on a case by case basis.

2.4.5. Article 32: Network characteristics

2.4.5.1. Network characteristics §32.1

This requirement is site specific and needs to be specified by the TSO on a case by case basis.

2.4.6. Article 33: HVDC system robustness

2.4.6.1. HVDC system robustness §33.1

This requirement is site specific and needs to be specified by the TSO on a case by case basis.

2.4.6.2. Network characteristics §33.2

This requirement is site specific and needs to be specified by the TSO on a case by case basis.

Commented [A9]: Duitsland ervaart hier problemen mee.
De netbeheerder moet aantonen aan de bestaande netgebruikers dat bestaande en nieuwe installaties niet geïmpacteerd worden.

2.5. Chapter 5: Requirements for protection devices and settings

2.5.1. Article 34: Electrical protection schemes and settings

2.5.1.1. Electrical protection schemes and settings §34.1

Following elements will need to be provided for under HVDC connection contract: Any scheme considered suitable for the HVDC system to meet the functional requirements may be proposed by the system owner. The System Owner shall, with adequate explanatory descriptions, demonstrate that the proposed schemes meet the criteria of speed, dependability, security, sensitivity and maintainability requirements. The System Owner shall provide proof that the protection scheme is not a prototype and has been successfully used in other similar installations. The relevant TSO reserves the right to adapt the protection scheme in mutual agreement with the System Owner in order to coordinate with the protection system of the AC system at the PCC.

Protective relay settings shall be completed by the System Owner and provided to the relevant TSO for review at least 3 months before the Tests on Completion program commencement date. Setting development explanations and calculations shall be provided with the protective relay settings.

2.5.1.2. Electrical protection schemes and settings §34.3

Idem §34.1

2.5.2. Article 35: Priority ranking of protection and control

2.5.2.1. Priority ranking of protection and control §35.1

A control scheme, specified by the HVDC system owner consisting of different control modes, including the settings of the specific parameters, shall be coordinated and agreed between the relevant TSO, the relevant system operator and the HVDC system owner. The control scheme, its setting development explanations and calculations shall be provided to the relevant TSO for review at least 3 months before the Tests on Completion program commencement date.

2.5.2.2. Priority ranking of protection and control §35.2

This requirement is site specific. It has to be agreed between the TSO and the HVDC system owner on a case by case basis.

2.5.3. Article 36: Changes to protection and control schemes and settings

2.5.3.1. Changes to protection and control schemes and settings §36.1

The design of the HVDC converter shall permit modifying control characteristics, control loop responses, and protection settings etc. of the control and protection systems for the purpose of on-site optimization and when deemed required in the future using the engineering workstation. The System Owner shall provide a secure method of preventing inadvertent change to implemented functions

2.5.3.2. Changes to protection and control schemes and settings §36.2

This requirement is site specific. It has to be agreed between the TSO and the HVDC system owner on a case by case basis.

2.5.3.3. Changes to protection and control schemes and settings §36.3

This requirement is site specific. It has to be agreed between the TSO and the HVDC system owner on a case by case basis.

2.6. Chapter 6: Requirements for power system restoration

2.6.1. Article 37: Black start

2.6.1.1. Black start §37.1

This requirement is site specific and needs to be specified by the TSO on a case by case basis.

2.6.1.2. Black start §37.2

This requirement is site specific and needs to be specified by the TSO on a case by case basis.

2.6.1.3. Black start §37.3

This requirement is site specific and needs to be specified by the TSO on a case by case basis.

3. TITLE III: Requirements for DC-connected power park modules and remote-end HVDC converter stations

3.1. Chapter 1: Requirements for DC-connected power park modules

3.1.1. Article 39: Frequency stability requirements

3.1.1.1. Frequency stability requirements §39.1

The requirement for DC-connected power park modules connected via HVDC systems which connect more than one control area to be capable of delivering coordinated frequency control is site specific and shall be specified by the TSO on a case by case basis.

3.1.1.2. Frequency ranges §39.2(a)

A nominal frequency other than 50 Hz or a frequency variable by design can be used, subject to agreement to TSO. In that case, the applicable frequency ranges and time periods shall be specified by the TSO on a case by case basis.

3.1.1.3. Wider frequency ranges §39.2(b)

The definition of wider frequency ranges and longer minimum times for operation is site specific. It may be agreed between TSO and DC-connected power park module owner on a case by case level to ensure the best use of the technical capabilities of a DC-connected power park module if needed to preserve or restore system security.

3.1.1.4. Automatic disconnection §39.2(c)

This requirement is site specific. It may be specified by the TSO on a case by case basis.

3.1.1.5. LFSM-O §39.4

The same requirements of the RfD Type D will be applied

3.1.1.6. Constant power §39.5

The same requirements of the RfD Type D will be applied

3.1.1.7. Active power controllability §39.6

The same requirements of the RfD Type D will be applied

3.1.1.8. LFSM-U §39.7

The same requirements of the RfD Type D will be applied

3.1.1.9. FSM with subject to a fast signal response §39.8

The same requirements of the RfD Type D will be applied

3.1.1.10. Frequency restoration §39.9

The same requirements of the RfD Type D will be applied

3.1.1.11. Frequencies other than 50Hz §39.10

This requirement is site specific. It may be specified by the TSO on a case by case basis.

3.1.2. Article 40: Reactive power and voltage requirements

3.1.2.1. Voltage ranges Annex VII Table 9 and 10

This requirement is site specific. It may be specified by the TSO on a case by case basis.

3.1.2.2. Agreement on wider voltage ranges or longer minimum times §40.1(b)

The definition of wider voltage ranges and longer minimum times for operation is site specific. It can be agreed between RSO/TSO and HVDC system owner on a case by case level.

3.1.2.3. Automatic disconnection §40.1(c)

This requirement is site specific. It is to be specified by the RSO/TSO on a case by case basis. The terms and settings for automatic disconnection shall be agreed between the relevant system operator, the TSO and DC-connected power park module owner.

3.1.2.4. Voltage ranges for other AC voltages §40.1(d)

This requirement is site specific. It may be specified by the TSO on a case by case basis.

3.1.2.5. Agreement how to meet reactive power requirements §40.1(e)

This requirement is site specific. It may be specified by the TSO on a case by case basis.

3.1.2.6. Reactive power capability §40.2(b)(i)

This requirement is site specific. It may be specified by the TSO on a case by case basis.

3.1.2.7. Reactive power capability §40.2(b)(ii)

This requirement is site specific. It may be specified by the TSO on a case by case basis.

3.1.2.8. Priority to active and reactive power contribution §40.3

This requirement is site specific. It may be specified by the TSO on a case by case basis.

3.1.3. Article 41: Control requirements

3.1.3.1. Synchronisation §41.1

During the energisation or synchronisation of a DCC-connected power park module to the AC network, the DCC-connected power park module shall have the capability to limit any voltage changes to a steady-state level. That steady-state level and the maximum magnitude, duration and measurement window of the voltage transients are site specific and are to be specified by the TSO on a case by case basis (eg in connection contract). The steady-state level shall not exceed 5 per cent of the pre-synchronisation voltage.

3.1.3.2. Output signals §41.2

This requirement is site specific. It may be specified by the TSO on a case by case basis.

3.1.4. Article 42: Network characteristics

3.1.4.1. Method of pre-fault and post-fault conditions §42(a)

This requirement is site specific. It may be specified by the TSO on a case by case basis.

3.1.4.2. Equivalent representing the collection grid §42(c)

This requirement is site specific. It may be specified by the TSO on a case by case basis.

3.1.5. Article 43: Protection requirements

3.1.5.1. Electrical protection schemes §43.1

This requirement will be specified based on article 14.5 of RfG NC.

3.1.6. Article 44: Power quality

3.1.6.1. Power quality §44

This non-exhaustive requirement related to power quality will be based on the relevant Synergrid regulations regarding power quality, unless more stringent requirements are set forth in the connection contract.

Commented [A10]: Why not IEC

3.2. Chapter 2: Requirements for remote-end HVDC converter stations

3.2.1. Article 47: Frequency stability requirements

3.2.1.1. Frequency ranges §47.1

This requirement is site specific. It may be specified by the TSO on a case by case basis.

3.2.1.2. Frequency ranges §47.2

This requirement is site specific. It may be specified by the TSO on a case by case basis.

3.2.2. Article 48: Reactive power and voltage requirements

3.2.2.1. Reactive power and voltage ranges Annex VIII Table 12 and 13

This requirement is site specific. It may be specified by the TSO on a case by case basis.

3.2.2.2. Agreement on wider voltage ranges or longer minimum times §48.1(b)

The definition of wider voltage ranges and longer minimum times for operation is site specific. It can be agreed between RSO/TSO and DC-connected power park module owner on a case by case level.

3.2.2.3. Voltage ranges for other AC voltages §48.1(c)

This requirement is site specific. It may be specified by the TSO on a case by case basis.

3.2.2.4. Reactive power provision §48.2(a)

This requirement is site specific. It may be specified by the TSO on a case by case basis.

3.2.2.5. U-Q/Pmax – profile §48.2(a)

This requirement is site specific. It may be specified by the TSO on a case by case basis.

3.2.3. Article 50: Power quality

3.2.3.1. Power quality §50

This non-exhaustive requirement related to power quality will be based on the relevant Synergrid regulations regarding power quality, unless more stringent requirements are set forth in the connection contract.

Commented [A11]: In overeenstemming met de PPI eigenaars. Synergrid heeft geen specificaties omtrent subharmonische distortions.

Zie ook 2.4.4

4. TITLE IV: Information Exchange and Coordination

4.1.1. Article 51: Operation of HVDC systems

4.1.1.1. Operation of HVDC systems §51.1

The automatic controller hierarchy is site specific. It will be specified by the TSO on a case by case basis.

4.1.1.2. Operation of HVDC systems §51.4

This requirement is site specific. It may be specified by the TSO on a case by case basis.

4.1.2. Article 52: Parameters and settings

This requirement is subject of a mutual agreement between the relevant TSO and the HVDC system owner on a case by case basis.

4.1.3. Article 53: Fault recording and monitoring

4.1.3.1. Fault recording and monitoring §53.2 to 53.5

This requirement is site specific. It may be specified by the TSO on a case by case basis.

4.1.4. Article 54: Simulation models

4.1.4.1. Simulation models §54.1

The stipulated simulation models always need to be provided to the RST/TSO. The format is subject of a mutual agreement between the relevant TSO and the HVDC system owner on a case by case basis.

Formatted: French (Belgium)

5. References

- [1] 'Network Code on High Voltage Direct Current' or 'NC HVDC': Commission Regulation (EU) 2016/1447 of 26 August 2016 establishing a network code on requirements for grid connection of high voltage direct current systems and direct current-connected power park modules, <http://eur-lex.europa.eu/legalcontent/EN/TXT/PDF/?uri=CELEX:32016R1447&from=EN>
- [2] 'Network Code Requirements for Generators' or 'NC RfG': Commission Regulation (EU) 2016/631 of 14 April 2016 establishing a network code on

requirements for grid connection of generators, <http://eur-lex.europa.eu/legalcontent/EN/TXT/PDF/?uri=CELEX:32016R0631&from=EN>

[3] 'Network Code on Demand Connection' or 'NC DCC': Commission Regulation (EU) 2016/1388 of 17 August 2016 establishing a Network Code on Demand Connection, <http://eur-lex.europa.eu/legalcontent/EN/TXT/PDF/?uri=CELEX:32016R1388&from=EN>

[4] Federal Technical Reglement-
19 DECEMBER 2002. — Koninklijk besluit houdende een technisch reglement voor het beheer van het transmissienet van elektriciteit en de toegang ertoe, Arrêté royal établissant un règlement technique pour la gestion du réseau de transport de l'électricité et l'accès à celui-ci, <http://www.elia.be/~media/files/Elia/publications-2/gridcodes/Technisch%20reglement%20Federaal%202002.pdf>,

[5] Presentation FOD/SPF Energy in WG Belgian Grid (in Dutch): http://www.elia.be/~media/files/Elia/users-group/WG%20Belgian%20Grid/20170307%20WG%20Belgian%20Grid/FOD_Vision-for_FederalGridCode.pdf

Minutes of Meeting WG Belgian Grid 7th March 2017 (in French): http://www.elia.be/~media/files/Elia/users-group/WG%20Belgian%20Grid/20170421_WG%20BG/20170307_PV_WGBG_FR_FINAL_WRITTEN-APPROVED.pdf

[6] ENTSO-E Guidance document for national implementation for network codes on grid connection : Parameters of Non-exhaustive requirements, 16 November 2016: https://www.entsoe.eu/Documents/Network%20codes%20documents/NC%20RfG/161116_IGD_General%20guidance%20on%20parameters_for%20publication.pdf

Formatted: Dutch (Belgium)

Field Code Changed

Formatted: Dutch (Belgium)

Field Code Changed

Formatted: Dutch (Belgium)

Field Code Changed

Formatted: Dutch (Belgium)

Field Code Changed

Formatted: Dutch (Belgium)

Field Code Changed

Formatted: Dutch (Belgium)

Field Code Changed

Formatted: Dutch (Belgium)

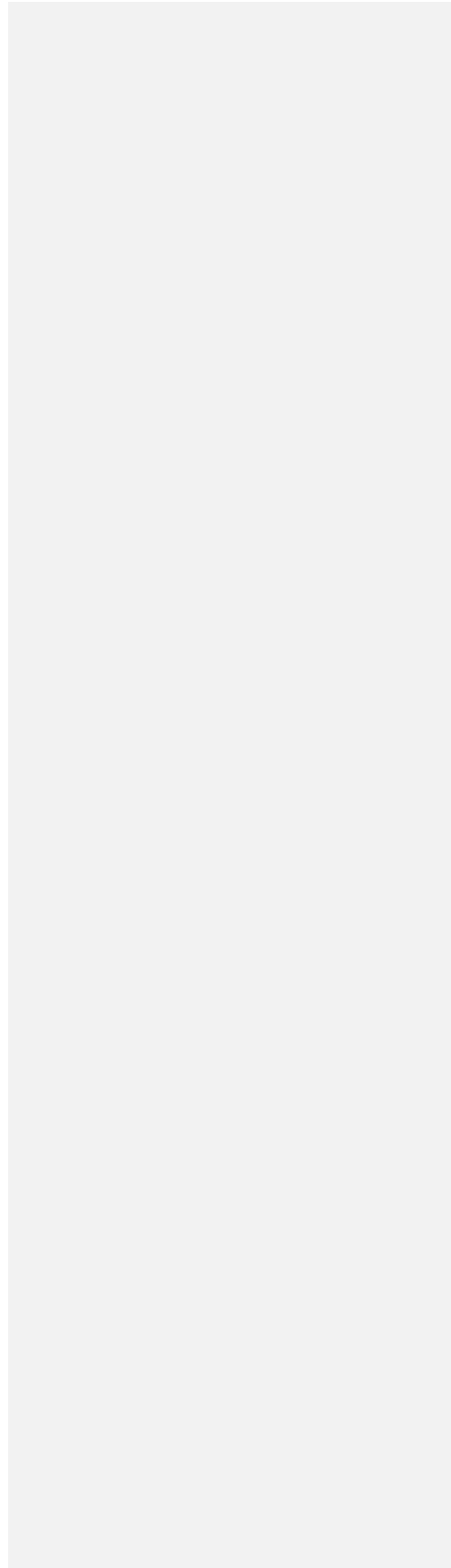
6. Appendix - List of non-exhaustive articles for HVDC

This list is extracted from ENTSO-E Guidance document for national implementation for network codes on grid connection : Parameters of Non-exhaustive requirements [6]



PROPOSAL FOR STORAGE CONNECTION REQUIREMENTS

Public consultation 15 March – 23 April 2018



Contents

1 Introduction and background	112
2 Definitions and applicability	222
3 SPM categories types	333
4 SPM Type A.....	334
4.1 Frequency stability & active power management.....	334
4.1.1 Frequency withstand capability.....	444
4.1.2 Rate Of Change Of Frequency (ROCOF) withstand capability and Loss of Main protection	444
4.1.3 Limited Frequency Sensitive Mode (LFSM-O and LFSM-U)	444
4.1.4 Admissible maximum power reduction with falling frequency	555
4.1.5 Logical interface to cease active power injection.....	555
4.1.6 Automatic connection.....	666
4.1.7 Rates of change of active power output.....	666
4.2 Information exchange.....	666
5 SPM Type B.....	666
5.1 Frequency stability and active power management.....	666
5.1.1 Remote control reduction of active power	666
5.1.1 Automatic reconnection	666
5.2 Instrumentation and information exchange	777
5.2.1 Structural data	777
5.2.2 Real-time measurements.....	777
5.2.3 Data to be received	777
5.3 Fault-ride through for symmetrical and asymmetrical faults	888
5.4 Reactive capabilities	888
5.5 Fault Current & dynamic voltage support (optional).....	999
5.6 Post-fault active power recovery (optional)	999
6 SPM Type C.....	999
6.1 Frequency stability & Active Power management.....	999
6.1.1 Active Power Controllability and Control Range.....	999
6.1.2 Limited frequency sensitive mode – under frequency (LFSM-U)	101010
6.1.3 Frequency Sensitive Mode	101010
6.1.4 Frequency restoration control.....	101010
6.1.5 Real-time monitoring of FSM.....	101010
6.1.1 Automatic disconnection for voltage outside ranges	101010
6.2 System restoration.....	111110
6.3 Reactive capabilities	111111
6.4 Voltage control	121212
7 SPM Type D	121212
7.1 Fault-ride through for symmetrical and asymmetrical faults	121212
7.2 Voltage withstand capabilities	121212
7.3 Resynchronization.....	121212
8 References	131313

1 Introduction and background

Electric storage systems are out of the scope of Connections Network Codes (CNCs) as referred in the Art 3-2 (d) in the RfG NC [1] and the Art 3-2 (b) in the DCC NC [2] with the exception of pump-storage which is considered as a Power Generating Module (PGM).

Commented [A1]: De omschrijving van de opslagsystemen die onder het toepassingsgebied vallen blijft onduidelijk.

1. Waar is de uitzondering voor noodbatterijen vermeld?
2. Batterijen die geen netdiensten leveren (bijvoorbeeld UPS; peak shaving in industriële omgeving) moeten buiten de scope vallen: enkel batterij die marktdiensten aanbieden mogen onder deze regelgeving vallen.
3. Wat met andere vormen van opslag naast elektrisch (condensator): mechanisch (vliegwiel); batterijen (chemisch)?

Commented [A2]: Er wordt nergens gewag gemaakt dat dergelijke installaties beperkte levering /afname van energie in de tijd hebben. Hoe zal hiermee omgegaan worden.

Expected new storage capacities to be installed in Belgium would therefore require the development of adequate technical capabilities to close such gap with the aim to address system needs and to contribute to secure system operation. In this document we propose a set of minimum technical connection requirements for Storage Park Modules (SPM) as per the scope, the relevant terminologies and definitions used in the section 2 which cannot be considered as a part of the set of the general Requirements requested within the CNCs. The proposed technical requirements are based on categories reflecting the significance and the expected capabilities of the storage system coherently with the ABCD limits defined for PGMs.

Commented [A3]: Wat is de definitie van nieuw in deze context?

In general the possible technical capabilities of a SPM are similar to the ones of Power Park Modules (PPM) as they share similar technical aspects as modules connected to electricity networks through power electronics acting as inverter and rectifier for the case of SPM. Therefore, the proposed technical capabilities are aligned as much as possible with the PPM's exhaustive and non-exhaustive requirements defined in the RfG NC [1].

Commented [A4]: RfG describes only requirements for pump hydro in the charging mode.

The main focus of this document is to define the minimal technical requirements specifically applicable to storage systems taking into consideration specific intrinsic behavior of SPM, as well as the different operational modes as charging or discharging modes. Therefore, whenever no specific distinct provisions are required for SPM, the exhaustive and non-exhaustive requirements for PPM would be of application.

This document fixes the technical requirements that are subject to definition by the relevant TSO (Elia) and Elia as a Relevant System Operator. They are therefore applicable to the SPM connected to transmission network and whenever relevant to SPM connected to DSO or CDSO networks for requirements covering frequency stability and system robustness in alignment with ENTSO-e guidance document for National Implementation of connection Network Codes [3].

2 Definitions and applicability

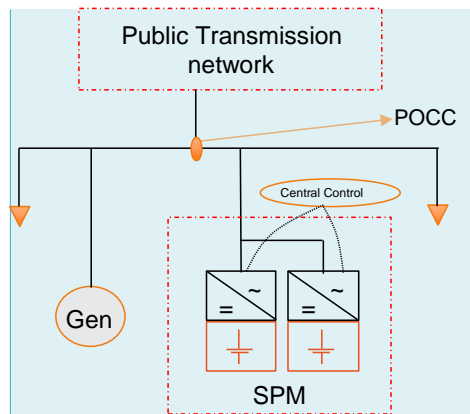


Figure 1 Example of Storage Park Module grid connection

Commented [A5]: POCC → Connection point

Figure 1 illustrates possible grid connection of a SPM and the Point Of Common Coupling (referred in this document as the connection point) to the transmission grid. The same facility could include other Power Generation Modules or demand units as auxiliary supply.

Commented [A6]: What is exactly meant by this? Does it mean that the regulation does not cover storage at a demand facility?

Below is a set of applicable definitions covering intrinsic capabilities of a SPM or relevant operational modes addressed within the current technical connection requirements:

- a. **Storage Park Module (SPM):** An electric system composed of a single or multiple electrical storage units capable of storing, delivering electrical energy into a single electrical point of connection.
- b. **Power max (Pmax):** the maximum active power which the SPM is technically designed to deliver or absorb at the connection point.
- c. **State Of Charge (SOC):** the measure of the amount of the available capacity expressed in percentage points (0% = empty; 100% = full).
- d. **Maximum Charging Ramp Rate (Rch):** the maximum limit on the rates of change of power that the SPM is capable of achieving during charging expressed in MW/minute.
- e. **Maximum Discharging Ramp rate (Rdis):** the maximum ramping that the SPM is capable of achieving during discharging expressed in MW/minute.

The current connection requirements are applicable to both stationary and non-stationary storage applications - which includes for example Vehicles-to-Grid (V2G) applications. On the other hand railway traction in generative mode are not within the scope of this document. The current connection requirements are applicable to new installations and existing installations to which substantial modifications will be made.

The current connection requirements in this document are not applicable to emergency Uninterruptible Power Supply and any specific electrical storage application operating in parallel less than five minutes per calendar month while the system is in normal system state, in alignment with the RfG NC provisions of the Article 3(2) [1].

Commented [A7]: The definition should be reviewed and improved, e.g:

- Electrical energy is usually not stored, but stored in another form (cinetic, chemical, ...)
- Should we read 'storing and delivering' or storing OR delivering'? What if it's only one of the two?
- If there is no injection of energy into the public grid, then there's no 'delivery into a single electrical point of connection', hence the unit is not covered by the regulation?

Commented [A8]: Zie hierboven

Commented [A9]: De bepaling van de SOC moet rekening houden technische kenmerken van de installatie.

Commented [A10]: Non-stationary application should be excluded from the regulation, as they present very specific characteristics that cannot be covered by the general requirements on storage. For example, an EV charging station does not have a state-of-charge. In all cases, EV charging station without V2G possibility should clearly be excluded from the regulation as they do not constitute storage from the point of view of the grid.

3 SPM categories types

The present technical requirements are defined per each of the following categories taking into consideration the Pmax characteristic of the SPM in the connection point:

- Type A
 - 0.
 - $8kW \leq Pmax < 1 MW$
- Type B
 -
 - $1 MW \leq Pmax < 25MW$
- Type C
 - $25MW \leq Pmax < 75MW$
- Type D
 - $75MW \leq Pmax$

4 SPM Type A

4.1 Frequency stability & active power management

4.1.1 Frequency withstand capability

PGM exhaustive and non-exhaustive requirements on frequency withstanding capabilities [see Art. 13-1 (a) RfG NC] are of application for all SPM of type A, B, C and D in the Belgian Control Area.

4.1.2 Rate Of Change Of Frequency (ROCOF) withstand capability and Loss of Main protection

PGM exhaustive and non-exhaustive requirements on Rate Of Change Of Frequency (ROCOF) withstand capability and Loss of Main Protection triggered by rate-of-change-offrequency-type [see Art 13.1(b) RfG NC] are of application for all SPM type A, B, C and D in the Belgian Control Area.

4.1.3 Limited Frequency Sensitive Mode (LFSM-O and LFSM-U)

Considering the principles of the Art. 15-3 of the Emergency and Restoration Network Code [4] , all SPM type A, B, C and D in the Belgian Control Area, should have LFSM-O and LFSM-U technical capabilities [see Art. 13-2 (a-g) and Art. 15-2 RfG NC].

In the event of large frequency deviations, the SPM must in priority contribute to ensuring frequency stability by automatically increasing or reducing active power injection or absorption at grid frequencies below or above the reference frequencies f_1 and f_2 , in accordance with Figure 2 and the parameters defined in Table 1.

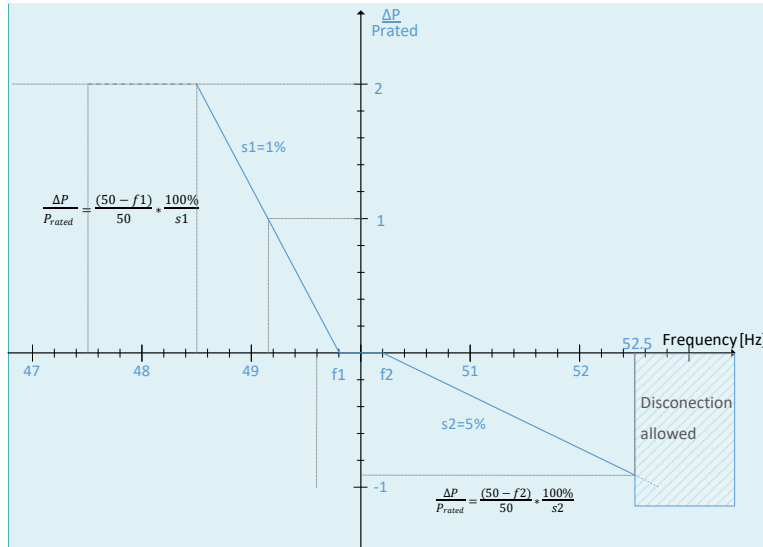
In application of the article 15.3 (b) of the Emergency and Restoration NC, a SPM that cannot achieve a reverse into ~~discharging~~ generating mode prior to automatic low frequency demand disconnection scheme shall disconnect. The disconnection shall not be enforced by default, but only allowed in the case that a discharging mode cannot be achieved prior to the frequency threshold of 49 Hz.

For justified safety or technical security reasons, the owner of the SPM might agree with the relevant system operator on applicable minimum and/or maximum SOC limits on his connection agreement.

Commented [A11]: RfG NC does not apply to storage devices. It should not be allowed to make this reference? See also this reference below.

Art.15 of RfG applies only to type C&D.

Commented [A12]:



Commented [A13]: See definition of Pmax.
Prated = 0.5 x Pmax.
Not logic: therefor the proposal to modify this in a value of Pmax instead of DeltaP/Prated

Figure 2 Limited Frequency Sensitive response capabilities for a SPM

Table 1 Limited Frequency Sensitive response parameters for a SPM

Parameters	Default value
f1	49.8 Hz
f2	50.2 Hz
s1	1% Selectable within a range of 0.1 and 12%
s2	5 % Selectable within a range of 0.1 and 12%
Settling time	As fast as possible maximum 30 seconds
First reaction	By default as fast as technically possible (no intentional delay), specific provisions could be applicable by the DSOs in agreement with Elia.

Commented [A14]: Definition is missing

Commented [A15]: Definition is missing

4.1.4 Admissible maximum power reduction with falling frequency

This requirement set in Art. 13-4 RfG NC is not applicable for a SPM as they do not have technical limitation with that respect.

4.1.5 Logical interface to cease active power injection

SPM of type A and B connected the transmission network shall be equipped with a logical interface to cease active power injection or absorption, as per the requirement for PGM type A [see Art 13-6 RfG NC]. The SPM shall be capable of ceasing power injection or absorption to zero within 5 seconds after instruction is given via the reception of an external signal. The remote operation is site specific: Elia can request remote operation as per the provisions in the subsection 4.2.

Commented [A16]: Hoe wordt dit signaal aangeleverd? Elia moet verantwoordelijk zijn voor de aanlevering van het signaal tot de asset. Wanneer kan Elia dit sturen? Niet tijdens 'Normal' of 'Alert' state.

4.1.6 Automatic connection

The general condition for connection of SPM in the Belgian Control Area are defined as following:

- Frequency range between: 49.9 and 50.1 Hz and
- Voltage range between: 0.85 and 1.1 pu of Nominal voltage and
- Temporization: 60 seconds

Commented [A17]: Zeer smalle range waar deze eenheden terug mogen aansluiten.

Commented [A18]: Vertaling?

Automatic Connection to transmission network is only allowed for SPM Type A, like this is allowed to the PGM type A [see Art 13-7 RfG NC]. Subsequent to the connection, the SPM shall be capable to limit the maximum admissible gradient of active power (unless subject to LFSM requirement) as following:

- Charging mode: <=20 % Pmax per minute
- Discharging mode: <=20% Pmax per minute

The active power gradient restriction is only applicable following the connection of the overall SPM system and not during normal operational mode. Note that the connection of a single non-stationary storage unit, as an electric vehicle (not the overall SPM), would not therefore require an active power gradient restriction on either charging or discharging modes.

Commented [A19]: Definitie?

Commented [A20]: Niet duidelijk, gelieve te herschrijven.

4.1.7 Rates of change of active power output

Unless subject to emergency operation and frequency control requirements, Elia (or the RSO) have the right to specify a maximum ramping limitation of active power output for fast charging and discharging rates expressed in percentage point of Pmax per second, similarly to PGM type C [see Art 15-6(e) RfG NC].

4.2 Information exchange

There are no requested capabilities to establish real time communication: SPM of type A shall be equipped to receive and comply to an external signal sent by Elia to cease charging or discharging.

Commented [A21]: Aangezien dit van toepassing is op thuisbatterijen.

Wat bedoeld men hiermee: een ethernetpoortingang of wifi? Elia zelf moet verantwoordelijk zijn om het signaal tot hier te krijgen.

Signal#	Request to cease active Power absorption or injection	Binary 1: Request Active 0: End of request
---------	---	--

Commented [A22]: Waarom geen 2 signalen? Wat is het idee erachter?

At low frequency charging has to stop, but - with only one order - also batteries generating power will cease injection.

5 SPM Type B

In addition to the specifications for SPM type A, the following is requested.

5.1 Frequency stability and active power management

5.1.1 Remote control reduction of active power

The SPM shall be capable, like the PGMs of type B [see Art 14 -2 RfG NC], of reducing its power injection or absorption. The setpoint sent by Elia must be reached within a maximum duration of 1 minute and a precision of 5% after instruction is given via the reception of an external signal. Elia can request remote operation as per the provisions in subsection 5.2.3.

Commented [A23]: Waarom moet Elia een setpoint kunnen sturen voor deze batterijen? Indien noodzakelijk moet hiervoor een markt worden gecreëerd.

5.1.1 Automatic reconnection

The general condition for reconnection of SPM in the Belgian Control area are defined as following

Dit mag niet van toepassing zijn wanneer de markt in 'normal' of 'alert' modus is. Eenmaal Elia de sturing overneemt, moet hier een vergoeding tegenover staan (energie/alternatieve opportuniteiten)!

- Frequency range between: 49.9 and 50.1 Hz and
- Voltage range between: 0.9 and 1.1 pu of Nominal voltage and
- Temporization: 60 seconds

Commented [A24]: Zeer smalle range waar deze eenheden terug mogen aansluiten in geval van wederopbouw van het net.

Commented [A25]: Vertaling

For SPM units of Type B, C and D connected the Transmission Network, automatic reconnection is prohibited and subject to authorization in their connection contracts, like the PGMs of Type B, C and D [see Art 14 -4 (a-b) RfG NC].

Note that a signal allowing the reconnection is foreseen in the sub-section 5.2.3. Subsequent to the reconnection the SPM is required to limit the admissible gradient of active power to the following (unless subject to LFSM requirement):

Commented [A26]: LFSM becomes active at wider values than 49.9 and 50.1. So impossible: proposal to delete this sentence.

Charging mode: 10 % Pmax per minute
Discharging mode: 10% Pmax per minute

5.2 Instrumentation and information exchange

Beside what is being requested for PGM in general in Art. 14-5(a, b and d) RfG NC, the following is requested for SPM connected to transmission network:

Commented [A27]: RfG niet van toepassing op batterijen

Wat wordt bedoeld met 'beside'? 'In addition to'?

5.2.1 Structural data

Beside what is being requested for PGM in general, the following is requested for SPM connected to transmission network:

Commented [A28]: Quid connected to DSO?

EG	Gross Energy Capacity	[MWh]
Enet	Net Energy Capacity	[MWh]
Pmax	Maximum rated active power capacity	[MW]
SOCmin	Minimum State of Charge	[%]
SOCmax	Maximum State of Charge	[%]
Rch	Maximum charging rate	[MW/min]
Rdis	Maximum discharging rate	[MW/min]

5.2.2 Real-time measurements

Beside what is being requested for PGM in general, the following is requested for SPM connected o transmission level:

SOC	State of charge	[%]
-----	-----------------	-----

5.2.3 Data to be received

Beside what is being requested for PGM in general, the following is requested for SPM :

Signal#	Clearance to reconnect	Binary 0: No reconnection 1: Clearance
---------	------------------------	--

Signal#	Request to reduce Active Power absorption or injection	Binary
		1: Request Active 0: End of request
Signal#	Active power setpoint expressed in MW	Value
		Charging/discharging

Commented [A29]: Zie opmerking tabel 4.2

Commented [A30]: Zie opmerking tabel 4.2

5.3 Fault-ride through for symmetrical and asymmetrical faults

PPM type B exhaustive and non-exhaustive requirements on fault-ride through for symmetrical and asymmetrical faults [see Art 20-3 RfG NC] are of application for SPM type B.

5.4 Reactive capabilities

The required reactive capabilities of SPM connected at transmission network should be met at the HV side of the step up transformer if existing; otherwise they should be met at the convertor terminals.

A SPM type B shall be capable of providing, like the PPM type B [see Art 20-2(a) RfG NC], the reactive power capabilities determined by the Q-P profile as represented in the Figure 3 adapted for both charging and discharging modes.

The limitations-capabilities are based on nominal current at high active power and by a power factor $(\cos(\phi))$ reactive power defined by the 2 points at $Q = -33\%$ and $+33\%$ of P_D , where P_D is the maximum active power that can be produced or absorbed in case of the maximum requested reactive power output (hence equal to $0.95 \cdot S_{nom}$). For voltage different from 1 p.u, the capabilities are defined as per the U-Q/ P_D profile represented in Figure 4. Note that the available capability of the SPM (which could be wider than the minimum requirement) should be communicated, demonstrated and put at disposal of the relevant system operator. The owner of the SPM is not allowed to refuse the use of the reactive capability without a technical justification. The SPM is therefore expected to not limit its capabilities to comply with the minimum requirement but to use the full capability to support the system stability as stated in its agreement. In case the SPM has already the capability of voltage regulation, one should not refuse the relevant system operator to make use of it. In this case, the settings of the controllers should be agreed with the relevant system operator.

Commented [A31]: Indien een batterij embedded is in een industrieel net of CDS, moet het mogelijk zijn om de eis van reactief vermogen ook te laten invullen door andere assets.

Indien de batterij niet embedded is, hebben we de volgende vragen. Hoe moeten we dit aantonen? Wenst Elia het reactief vermogen op afstand te kunnen sturen en op welke manier?

Commented [A32]:

Commented [A33]:

Commented [A34]: Values needed for all voltage levels

Commented [A35]: Investeerder worden naar hogere uitgaven geduwd. Welke vergoeding voorziet Elia om de full capability aan te bieden?

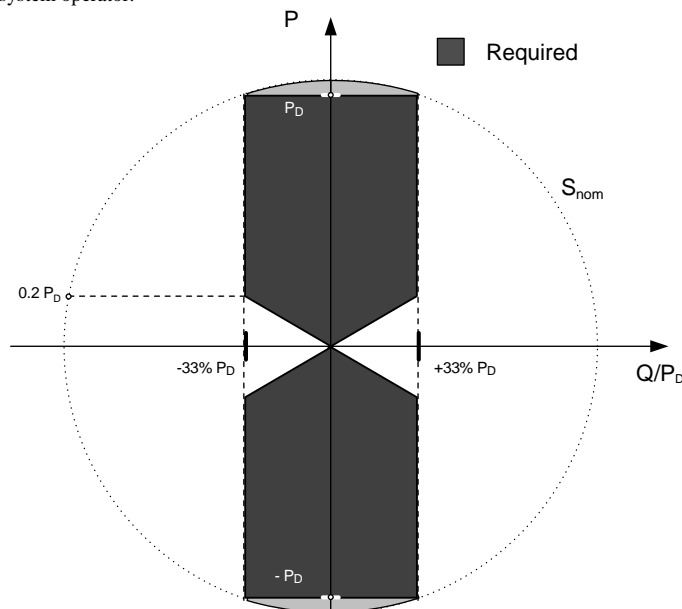


Figure 3: Capability curve for SPM type B

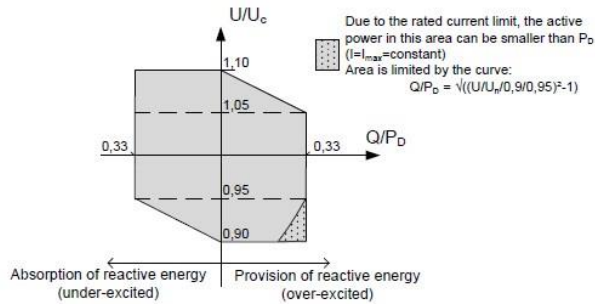


Figure 4: U-Q/P₀ profile for type B PPM in order to visualize reactive power requirements for voltages different from 1pu.

5.5 Fault Current & dynamic voltage support (optional)

The requirement is optional for SPM, if requested the PPM *type B* exhaustive and non-exhaustive requirements on Fault Current & dynamic voltage support [see Art 20-2 (b and c) RfG NC] would be of application for both charging and discharging modes if it is decided to be applied.

5.6 Post-fault active power recovery (optional)

The requirement is optional for SPM, if requested the PPM *type B* exhaustive and non-exhaustive requirements on post-fault active power recovery [see Art 20-3 RfG NC] are of application for both charging and discharging modes if it is decided to be applied.

Commented [A36]: Only for generating mode, not for charging mode

6 SPM Type C

In addition to the specifications for SPM type B, the following is requested.

6.1 Frequency stability& Active Power management

6.1.1 Active Power Controllability and Control Range

The SPM type C connected to transmission network, like the PGM type C [see Art. 15-2 (a) RfG NC], shall be capable of controlling active power injection or absorption to a requested setpoint within a maximum duration of 1 minute (T_s) and a precision of 5% (Setpoint tolerance) after instruction is given as per the Figure 5.

Commented [A37]: Zie opmerking omtrent sturen van installatie hierboven.

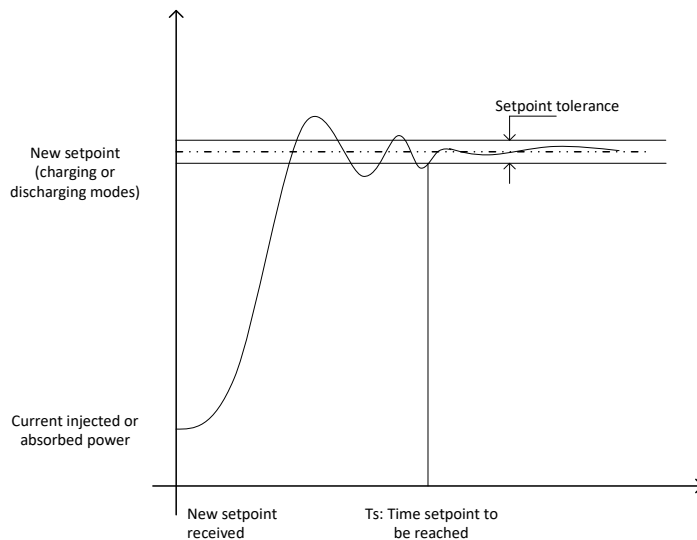


Figure 5 Tolerance and time duration for SPM application of new set point of active power.

6.1.2 Limited frequency sensitive mode – under frequency (LFSM-U)

This requirement on Limited frequency sensitive mode – under frequency (LFSM-U) [see Art. 15-2 (c) RfG NC for the PGM type C] is already covered by the requirements fixed in the section 4.1.3 and therefore applicable to all SPM types A, B, C and D [in the Belgian Control Area](#).

6.1.3 Frequency Sensitive Mode

PPM type C exhaustive and non-exhaustive requirements on Frequency Sensitive Mode [see Art. 15.2.d RfG NC] are applicable to SPM of type C and D in the Belgian Control Area, taking into consideration applicable provisions for units with limited energy reservoirs as defined in the [System Operation Guidelines](#) and Elia's FCR General Framework Agreement.

Commented [A38]: Requirements to add in the text or as attachment.

6.1.4 Frequency restoration control

As per PPM type C exhaustive and non-exhaustive requirements on Frequency restoration control [see Art 15-2.(e) RfG NC] and [Elia's aFRR General Framework Agreement](#).

Commented [A39]: To specify in detail

6.1.5 Real-time monitoring of FSM

As per PPM *type C* exhaustive and non-exhaustive requirements on Real-time monitoring of FSM [see Art 15-2.(g) RfG NC] and Elia's General Framework Agreement.

6.1.1 Automatic disconnection for voltage outside ranges

As per PPM *type C* exhaustive and non-exhaustive requirements on Automatic disconnection for voltage outside ranges [see [Art 15-3 RfG NC](#)].

Commented [A40]: Meaning 'as specified in the connection agreement'

6.2 System restoration

As per PPM type C exhaustive and non-exhaustive requirements on capability ~~to take part in island operation~~ [see Art 15-5 (b) RfG NC] and the capability of quick resynchronization [see Art 15-5 (c) RfG NC].

Commented [A41]: 'Islanding' is niet relevant voor batterij.

Commented [A42]: Moet in het aansluitingscontract staan.

6.3 Reactive capabilities

This requirement should be met at the connection point.

A type C SPM connected to transmission network shall be capable of providing like the PPM Type C requirements [see Art 21-3(a-c) RfG NC], the reactive power within the Q-P profile described in Figure 6 for both charging and discharging modes. This profile has an obligated span of 0.6p.u. with regards to Q/Pmax, but can move within an area of [-0.3p.u., +0.35p.u.] represented by the outer envelope when accepted by Elia (based on the connection point, size and the characteristic of the SPM) as defined in the Figure 6. The reactive power can be uncontrolled within the shaded area, however, injected/absorbed values must be limited within a range of $Q = [-0.0329 ; +0.0329]$ p.u. of P_{max} ¹.

Commented [A43]: For consistency and level playing field change towards: *the required reactive capabilities should be met at the HV side of the step up transformer if existing; otherwise it should be met at the convertor terminals*

Commented [A44]: Hoe komt Elia aan deze waarden?

Commented [A45]: Dimensions on the P axis not specified.

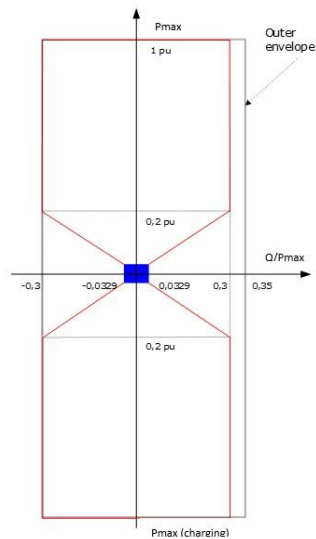


Figure 6: Reactive power capability for a Type C and D SPM.

For voltage different from 1 p.u, the capabilities are defined as per the U-Q/P_D profile represented in Figure 7.

¹ FGC Article 209 §3: 3,29 % = 10 % of the reactive range at $\cos(\phi) = 0.95$.

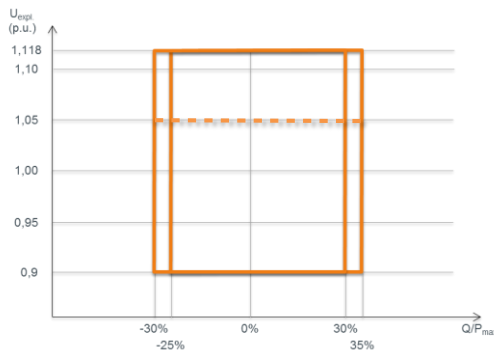


Figure 7 U-Q/Pmax profile for a type C and D SPM (dashed for nominal voltages above 300kV).

Commented [A46]: Max. voltage should be 1.1 pu and not 1.18 pu.

Note that the available capability of the SPM (which could be wider than the minimum requirement) should be communicated, demonstrated and put at disposal of the relevant system operator. The owner of the PPM is not allowed to refuse the use of the reactive capability without a technical justification. The SPM is therefore expected to not limit its capabilities to comply with the minimum requirement but to use the full capability to support the system stability as stated in its agreement.

6.4 Voltage control

As per PPM *type C* exhaustive and non-exhaustive requirements on Voltage control [see Art 21-3 (d) and (e) RfG NC] for both charging and discharging modes.

7 SPM Type D

7.1 Fault-ride through for symmetrical and asymmetrical faults

As per PPM *type D* exhaustive and non-exhaustive requirements on Fault-ride through for symmetrical and asymmetrical faults [see Art 22 RfG NC] for both charging and discharging modes.

Commented [A47]: The FRT applies in RfG only in generating mode.

7.2 Voltage withstand capabilities

As per PPM *type D* exhaustive and non-exhaustive requirements on voltage withstand capability and automatic-disconnection [see Art 16- 2 (a-b-c) RfG NC] for both charging and discharging modes.

7.3 Resynchronization

As per PPM *type D* exhaustive and non-exhaustive requirements on settings of synchronization devices [see Art 16- 4 (a) RfG NC] for both charging and discharging modes.

8 References

- [1] "'Network Code Requirements for Generators' or 'NC RfG': Commission Regulation (EU) 2016/631 of 14 April 2016 establishing a network code on requirements for grid connection of generators,," http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=OJ:JOL_2016_112_R_0001.
- [2] "'Network Code on Demand Connection': Commission Regulation (EU) 2016/1388 of 17 August 2016 establishing a Network Code on Demand Connection".
- [3] "Parameters of Non-exhaustive requirements: ENTSO-E Guidance document for national implementation for network codes on grid connection".
- [4] "'Network Code on Electricity Emergency and Restoration ': Commission Regulation (EU) 2017/2196 of 24 November 2017 establishing a network code on electricity emergency and restoration," <http://eur-lex.europa.eu/legalcontent/EN/TXT/PDF/?uri=CELEX:32017R2196&from=EN>.