EirGrid and ESB Networks' proposal for the general application of technical requirements in accordance with Articles 13 – 28 of the Commission Regulation (EU) 2016/631 establishing a network code on requirements for grid connection of generators

16 May 2018

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1. Introduction

On the 17th May 2016 the Commission Regulation (EU) 2016/631 establishing a network code on requirements for grid connection of generators[1] (hereafter referred to as 'RfG') entered into force.

The scope of this document is to seek approval from the National Regulatory Authority on EirGrid and ESB Networks' proposal for the general application of technical requirements in accordance with Articles 13 – 28 of the Commission Regulation (EU) 2016/631 establishing a network code on requirements for grid connection of generators.

This proposal document is produced jointly by EirGrid plc in its role as the Transmission System Operator in Ireland (hereafter referred to as the 'TSO') and ESB Networks in their role as the Distribution System Operator in Ireland (hereafter referred to as the 'DSO'). References in this document to the Relevant System Operator (hereafter referred to as the 'RSO') mean the operator of the system to which the generator is connected i.e. either the TSO or DSO.

The requirements of the RfG apply from three years after its publication as per Article 72. The requirements of RfG do not apply to existing Power Generating Modules (PGMs). A PGM is defined in Article 4 as existing if:

> (a) It is already connected to either the transmission or distribution network in Ireland by two years after entry into force of the RfG (17th May 2018); or
>
> (b) The power-generating facility owner has concluded a final and binding contract for the purchase of the main generating plant by two years after entry into force of the RfG (17th May 2018).

The requirements in RfG apply to generators with a Maximum Capacity[2] of 800 W or greater connecting to either the transmission or the distribution networks in Ireland. These requirements cover different technical criteria and apply to generators based on their RfG Classification Type[3] (i.e. A, B, C and D).

Under Article 7 (4) the RSO or TSO is required to submit a proposal for requirements of general application for approval by the Commission for Regulation of Utilities (CRU) within two years of entry into force of this Regulation i.e. 17th May 2018. The National Regulator then has six months to approve the proposal. It is not a requirement of RfG to consult upon the proposal for requirements of general application prior to submission to the CRU. The TSO and DSO issued a Consultation Document in the interest of transparency and to ensure that the TSO and DSO have the best information available to them to submit an appropriate set of recommendations to the CRU for the proposal of requirements of general application.

The TSO and DSO are submitting our proposal for the general application of the non-mandatory requirements and non-exhaustive[4] parameters in accordance with the requirements set out in Title II, Articles 13-28 of the RfG.

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[1] https://publications.europa.eu/en/publication-detail/-/publication/1267e3d1-0c3f-11e6-ba9a-01aa75ed71a1/language-en
[2] Refer to section 3.4 for more information on the definition of Maximum Capacity.
[3] Refer to section 3.2 for more information on the different types and bands within RfG
[4] Refer to section 3.1 for more information on non-exhaustive parameters and non-mandatory requirements.

SONI Ltd in its role as the Transmission System Operator in Northern Ireland and by Northern Ireland Electricity Networks in its role as the Distribution System Operator in Northern Ireland is submitting an equivalent proposal document to the Utility Regulator.

1.1. Associated documents

The TSO and DSO strongly recommend that all readers review the RfG Network Code, The RfG Consultation on Banding Thresholds in Ireland[5], RfG Banding Threshold Consultation Minded to Position in Ireland[6] and the RfG Banding Threshold Consultation Final Position in Ireland[7]

All references to Articles in this document refer to Articles set out in the RfG unless otherwise specified.

1.2. Definitions and Interpretations

For the purposes of this proposal document, terms used in this document shall have the meaning of the definitions included in Article 2 of RfG

In this proposal document, unless the context requires otherwise:

a) the singular indicates the plural and vice versa;
b) the table of contents and headings are inserted for convenience only and do not affect the interpretation of this proposal document; and
c) Any reference to legislation, regulations, directive, order, instrument, code or any other enactment shall include any modification, extension or re-enactment of it then in force.

1.3. Structure of this document

Sections 2 & 3 'Scope' and 'Background' provide important information that guide the reader through the RfG concepts and the principles underpinning this proposal document.

Section 4 sets out the consultation process, responses received and any changes from the Consultation Document to this proposal document.

Section 5 sets out the proposals that are being discussed in this document. It details the proposal, justification, applicability of parameter or requirement, a summary of the responses received and the System Operator (SO) response on each parameter, either TSO or DSO as relevant, as applicable.

In this document we have grouped parameters by technical theme, with a number of sub-themes discussed under each theme. Within each theme we go into detail on which parameter or requirement applies to each generator type. The themes are:

1. Frequency
2. Voltage
3. System Restoration
4. Protection & Instrumentation

[5] http://www.eirgridgroup.com/site-files/library/EirGrid/RfG-Banding-Thresholds-Consultation-Ireland.pdf

[6] http://www.eirgridgroup.com//library/EirGrid/RfG-Banding-Thresholds-Consultation_Minded-To-Position_Ireland.pdf

[7] http://www.eirgridgroup.com/site-files/library/EirGrid/RfG-Banding-Thresholds-Consultation_Final-Position_Ireland.pdf

2. Scope

The scope of this document is to seek approval from the National Regulatory Authority on EirGrid and ESB Networks' proposal for the general application of technical requirements in accordance with Articles 13 – 28 of the Commission Regulation (EU) 2016/631 establishing a network code on requirements for grid connection of generators. Our proposals include:

- making non-mandatory requirements mandatory; and
- Parameter selection for the non-exhaustive parameters.

Note this document does not seek approval on the mandatory requirements or exhaustive parameters. These have been set by the Commission and cannot be changed. Further information on some of the background to these decisions is available in the ENTSO-E FAQ document[8].

In some cases exhaustive requirements are described in this document to provide context for relevant discussion point and this will be clearly indicated.

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[8] http://www.acer.europa.eu/Media/News/Documents/120626-NC RfG - Frequently Asked Questions.pdf

3. Background

The RfG applies across the European Union. The RfG recognises that the requirements of power systems in different synchronous areas can be different due to the differing sizes. For this reason, the RfG provides that some of the requirements for general application are to be specified at National level, i.e. by the TSO, DSO or RSO of the member state, rather than at EU level.

To give effect to this concept the RfG contains requirements that are commonly described as either mandatory or non-mandatory and also requirements that are commonly described as exhaustive or non-exhaustive:

- A mandatory requirement must be applied by the TSO/DSO/RSO as appropriate
- A non-mandatory requirement is one which the TSO/DSO/RSO as appropriate may choose to apply
- An exhaustive parameter has a specified value or range in the RfG which the TSO/DSO/RSO as appropriate must apply
- A non-exhaustive parameter is one for which either:
    - The RfG provides a range from which the TSO/DSO/RSO as appropriate must select the applicable value for their region.
    - Or the RfG does not specify a value and the TSO/DSO/RSO as appropriate must select the applicable value for their region

As mandatory and exhaustive parameters are not at the discretion of the TSO/DSO/RSO as appropriate to modify they do not form part of this proposal document.

3.1. Principles underpinning the Proposals

Many of the requirements for general application exist in Ireland today in the Grid and/or Distribution Codes. Furthermore, many parameters and requirements in the Grid and Distribution Codes have been updated in recent years as a result of the work carried out under the DS3 Programme[9]. It is not intended to revisit this work.

<u>Non-Mandatory Requirement Selection</u>

In the majority of cases the following assumptions are made:

- Where the requirement provided in the RfG is an existing requirement in Ireland, the requirement is made mandatory nationally under the RfG.
- Where the requirement provided in the RfG is not an existing requirement in Ireland, the requirement is not made mandatory nationally under the RfG.

<u>Non-Exhaustive Parameter Selection</u>

There are two examples of non-exhaustive parameter selection under RfG;

1. RfG requests that the TSO/DSO/RSO selects the value from within a range or
2. RfG does not specify a range and requests that the TSO/DSO/RSO specify a value.

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[9] http://www.eirgridgroup.com/how-the-grid-works/ds3-programme/

In the majority of cases the following assumptions are made:

- Where the range for a non-exhaustive parameter provided in the RfG includes the existing value applied in Ireland, the existing value is proposed.
- Where the range for a non-exhaustive parameter provided in the RfG does not include the existing value applied in Ireland then the value proposed represents the minimum amount of change possible.
- Where the RfG does not provide a value for a non-exhaustive parameter but requests that the RSO defines the value and it is an existing parameter in Ireland, the existing value is proposed.
- Where the RfG does not provide a value for a non-exhaustive parameter but requests that the RSO defines the value and it is not an existing parameter in Ireland, a justification is given

3.2. Overview of Generator Types

Requirements for general application become increasing extensive as the size of the generator increases. RfG classifies all generators into one of four types A, B, C and D. Generator Types are primarily based on maximum capacity size. The **Final Position on Banding Threshold** proposes the following:

- Type A units range from 800 W up to 0.09[*] MW
- Type B units range from 0.1MW up to 4.9[*] MW
- Type C units range from 5 MW to 9.9[*]MW
- Type D units are great then 10MW

Note all generation connected at 110 kV or higher is automatically considered as Type D.

It is important to note the definition of Maximum Capacity in the RfG:

> *'maximum capacity' or 'Pmax' means the maximum continuous active power which a power-generating module can produce, less any demand associated solely with facilitating the operation of that power-generating module and not fed into the network as specified in the connection agreement or as agreed between the relevant system operator and the power-generating facility owner;*

Current Grid Code requirements are applied based on Maximum Export Capacity (MEC) or Registered Capacity.

All generation subject to the RfG will be considered based on the actual installed capacity less house load. **This represents a fundamental change to how requirements are applied to generators and should be fully understood by users.**

The majority of the RfG, Articles 13-16, covers the requirements for power generating modules or PGMs.

There are additional Articles detailing specific additional requirements for PGMs of different types. The three additional types are:

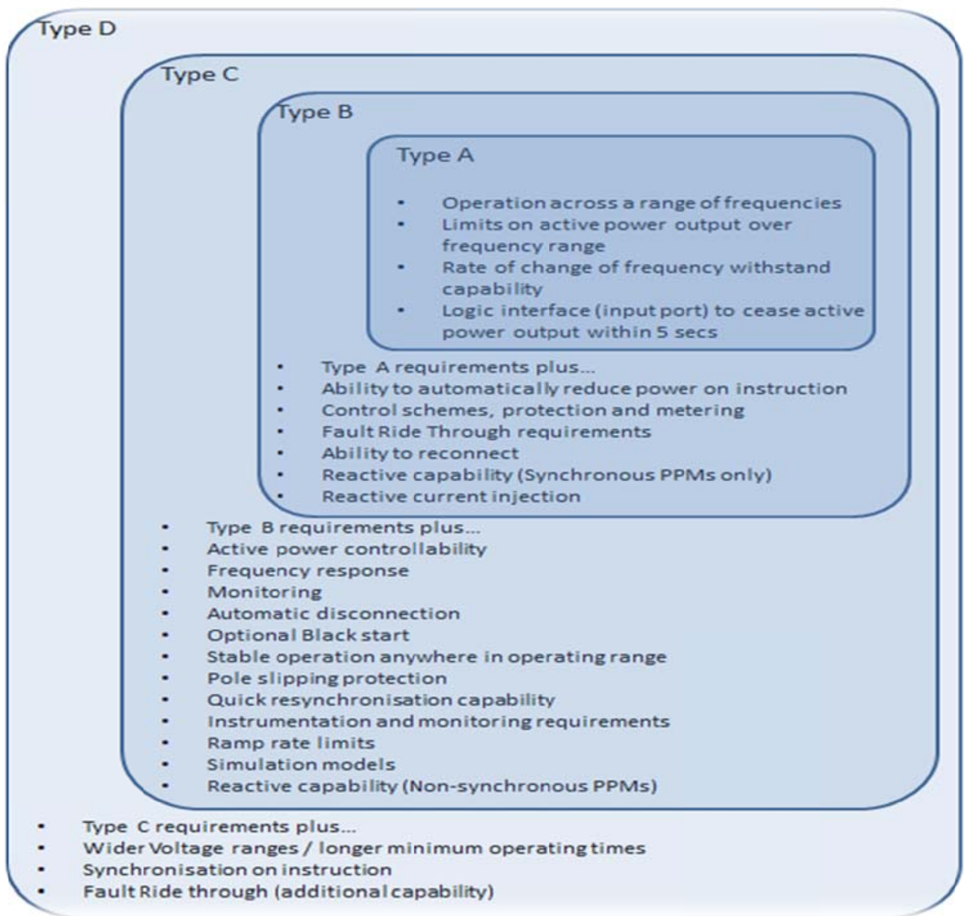
- Synchronous PGMs (SPGMs)
- Power Park Modules (PPMs)
- Offshore PPMs

Articles 17 – 19 cover additional requirements for synchronous PGMS or SPGMs.

Articles 20 – 22 cover additional requirements for PPMs

Articles 23 – 28 cover additional requirements for Offshore PPMs

An outline of the requirements of the RfG as applied to generators of each Type is shown below.



3.3. Overview of Topologies for Distribution Connected PGMs

Under the current Distribution Code, the applicability of different sections of the codes depends on the topology type. The current Distribution Code refers to Topology Types, types A, B, C, D, and E under section DCC11.1.3. Reconciliation of the newly defined RfG "Types" A, B, C, and D, with the pre-existing Distribution Code Types A, B, C, D, and E is required during the implementation of RfG.

Following the Banding Thresholds Consultation, the Final position paper states that ESBN and EirGrid are minded to re-name the existing Distribution Code Types A – E and adopt the newly named "Topologies 1-5". The definitions of these topologies will remain broadly as per the current Distribution Code

For the avoidance of doubt, where an RfG requirement is mandatory across a given RfG Type, this will be respected and applied to all topologies, and not only to a subset.

For the purpose of this proposal document, reference to 'type' is related to the RfG definition of type as per section 3.1, whilst reference to 'topology is a reference to the distribution 'types' as per the current Distribution Code.

Old Name	New Name
Type A	Topology 1
Type B	Topology 2
Type C	Topology 3
Type D	Topology 4
Type E	Topology 5

Table 1: Types Vs Topologies

4. Consultation Update

EirGrid and ESB Networks held a consultation on our proposal for the general application of technical requirements in accordance with Articles 13 – 28 of the RfG. This consultation opened on the 20th December 2017 for a period of 6 weeks until 9th February 2018. Following requests from a number of industry partners the consultation period was extended until February 16th 2018.

4.1. Summary of Submissions

The TSO received 13 individual submissions on the consultation of which 12 are not confidential and are included with this proposal document submission. Please note the majority of responses were provided in the excel template provided for the purpose on the EirGrid website and the collated response template has been included as an appendix to this proposal document. The other responses received were in pdf format and these are also included in the appendix.

There was one theme across a number of responses and that was in relation to the upper bound on the RfG U-Q outer envelope, which could have had follow on consequences for Connection Point voltages for certain connection methods on the distribution network. As per section 4.3 this has been given further consideration and a proposed outcome is described below which does not impact the submission of this proposal document.

Another theme was in relation to harmonisation of requirements across both jurisdictions on the Island of Ireland. The harmonisation of the two existing Grid Code would a very significant body of work and would involve the identification, assessment, determination and harmonisation of a large number of requirements and parameters which are not within the remit of the Network Codes. As such, it was decided that it would not be the optimum solution to combine the implementation of the Network Codes with the potential harmonisation of the existing Grid Codes.

There are no other 'standout' themes as the responses are very specific to the proposals being submitted. To that end we have included a summary of the submissions under each Article, as relevant, including the SO comment on the response received.

4.2. Summary of Changes to Proposals Post Consultation

In a number of cases the parameters proposed in the Consultation Document have been revised following industry submissions. These are highlighted throughout the document and are summarised in the table below. All other parameters are as per the consultation document.

Section No.	Table No.	Parameter	Consultation Proposal	Final Proposal
5.1.3.1	Table 6	Admissible reduction from maximum output with falling frequency	below 49 Hz falling by a reduction rate of 2% of the maximum capacity at 50 Hz per 1 Hz frequency drop	**For transient domain:** Below 49 Hz falling by a reduction rate of 2% of the maximum capacity at 50 Hz per 1 Hz frequency drop **For steady state domain:** Below 49.5 Hz falling by a reduction rate of 2% of the maximum capacity at 50 Hz per 1 Hz frequency drop
4.1.4.7	Table 17	Active power range	10%	SPGMs: 10% PPMs: 60% in 5 seconds and 100% in 15 seconds
5.2.2.1.1	Table 22	Maintain existing reactive power requirements in the Distribution Code.	Applicable for Type C and D SPGMs	Applicable for Type B SPGMs only
5.2.2.1.2	Table 23	Maintain existing reactive power requirements in the Distribution Code.	Applicable for Type C and D PPMs	Applicable for Type B PPMs only
5.2.2.2.1	Table 24	U_{max}(110 kV)	1.1pu	1.118pu
5.2.2.2.1	Table 24	U_{max}(220 kV)	1.1pu	1.118pu
5.2.2.2.1	Table 24	U_{min}(400 kV)	0.875pu	0.9pu
5.2.2.2.1	Table 25	U_{max}(10 kV & 20 kV)	1.1pu	1.118pu
5.2.2.2.1	Table 25	U_{max}(38 kV)	1.1pu	1.118pu
5.2.2.2.3	Table 27	U_{max}(110 kV)	1.1pu	1.118pu
5.2.2.2.3	Table 27	U_{max}(220 kV)	1.1pu	1.118pu
5.2.2.2.3	Table 27	U_{min}(400 kV)	0.875pu	0.9pu
5.2.2.2.3	Table 28	U_{max}(10 kV & 20 kV)	1.1pu	1.118pu

5.2.2.2.3	Table 28	U_{max}(38 kV)	1.1pu	1.118pu
5.2.2.2.3	Table 29	U_{max}(10 kV & 20 kV)	1.1pu	1.118pu
5.2.2.2.3	Table 29	U_{max}(38 kV)	1.1pu	1.118pu
5.2.2.5.1	Table 37	Requirement only applies to PPMs	C and D PGMs	C and D PPMs
5.2.2.5.2	Table 38	Requirement only applies to PPMs	C and D PGMs	C and D PPMs

4.3. Derogation Requests and Proposed Changes

There are three instances where derogations from the RfG Network Code are being sought.

1. Frequency Sensitive Mode, Active Power Range
2. Frequency Sensitive Mode, PPM Frequency Response Capability
3. Voltage Withstand Capability and Associated Reactive Power Maximum Voltage

There has been engagement with the CRU on these issues in advance of issuing this document.

Frequency Sensitive Mode, Active Power Range

Section 4.1.4.6; Article 15.2.d. (i) and (ii): FSM Parameter Selection (Table 16)

This Article requires an active power range ($\Delta P/P_{max}$) to be defined by the TSO within the ranges of 1.5% - 10%. The TSO did not believe that an active power range value should be specified for continuous FSM operation as governor droop defines the amount of active power that is provided by the PGM. The TSO consulted with the ENTSO-E Frequency Expert Group in relation to FSM. This group confirmed that this parameter was included in the above table as an error and as such we did not specify a parameter as part of the consultation.

ENTSO-E will be recommending an update to Table 16 to remove the requirement to specify this parameter, in the next iteration of the RfG Network Code.

Proposed Solution

In the interim, until the RfG has been updated at European level, the TSO will prepare a class derogation request to capture this error.

To this end, the TSO have not proposed a value for this parameter in Table 16 and feel that our derogation request will cover any implementation issues in this regard.

Frequency Sensitive Mode, PPM Frequency Response Capability

Section 4.1.4.7; Article 15.2.d. (iii): FSM Step: Change in Frequency (Table 17)

The TSO expressed our concerns in the Consultation Document in relation to a potential loss of frequency response from PPM units due to the limitations set out in RfG. The current requirements in the Grid Code require a 60% increase in Active Power within 5 seconds and 100% of expected increase (droop response) within 15 seconds of a frequency event. This requirement is core to the achievement of a 40% RES-E target and the ability to operate the system at System Non Synchronous Penetration (SNSP) levels up to 75%. The RfG range in Article 15.2.d only allows us specify a value for the change in power output relative to the Active Power output at the moment the frequency threshold was reached (or the maximum capacity as defined by the TSO) between 1.5-10% i.e. it does not allow us to specify the levels that currently exist in the Grid Code. However to lose the capability provided for in today's Grid Code would be very damaging to the success of the DS3 program and ultimately to the integration of high levels of renewable energy into the power system. We do not believe that the regulations intentionally undermine this capability.

Following discussions with ENTSO-E they have informed us that there is an understanding that the requirements under RfG are not intended to reduce the capability of the fleet of generation connected to a power system. The understanding is that once a National Code was submitted to the National Regulatory Authority by 2012 that the requirements of that code can be considered when implementing the RfG nationally.

Proposed Solution

Therefore the SO's are submitting a derogation request to the CRU in order to maintain the existing Grid Code requirements for Frequency response of PPMs.

Voltage Withstand Capability and Associated Reactive Power Maximum Voltage

Section 5.2.2.2.1; Article 18.2.b. (i): SPGM Parameters required for U-Q/Pmax Profile (Table 24)

Section 5.2.2.2.3 Article 21.3.b (i) & (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles (Table 27)

Following engagement with ENTSO-E, it has become apparent that there is an error in Article 18 Figure 7 and Article 21 Figure 8. The maximum voltage included in these diagrams is 1.1 p.u. whilst Article 16 Table 6.1 and Article 25 Table 10 show a maximum voltage withstand capability of 1.118 p.u. for connections greater or equal 110 kV and below 300 kV. It is incorrect that the reactive power capability range required at the connection point would be less than the withstand voltage that is defined at the connection point.

This applies for both the Ireland & Northern Ireland values and also the continental Europe values.

ENTSO-E will be recommending an update to these figures, Figure 7 and Figure 8 in the next iteration of the RfG Network Code.

For all other voltages, no such confirmation has been provided, and at this time there is no commitment that the range of operating voltages allowed on the Irish system would be provided for in future versions of the RfG Network Code.

Proposed Solutions

1. In the interim, until the RfG has been updated at European level, the RSOs will prepare a class derogation request for all PGMs connected at a voltage level greater or equal 110 kV and below 300 kV to capture this error.
   To this end, the RSOs have proposed a value of u_{max} in all instances that aligns with the correct value as per Article 18 and Article 21. The RSOs feel that our derogation requests will cover any implementation issues in this regard.

2. This does not apply to generators connected at Distribution voltages below 110kV (10kV, 20kV and 38kV). However, even if it did, it of itself will not be sufficient to deal with a historical misalignment. that has developed between the nominal voltages and the voltages to which the distribution system is currently planned and operated. Such is the quantum of this divergence, Connection Point voltages well in excess of 1.1pu of nominal are routinely encountered.

3. The requirement for the SOs to mandate the required reactive power behaviour would force ESBN to alter its Planning Standards going forward, which would have the potential to unacceptably restrict the quantum of generation that could be connected at a reasonable cost and/or introduce substantial increases in costs.

   Having considered this matter in great detail and consulted with CRU and Industry, ESBN is minded to pursue the following course of action. A Modification Proposal will be made to the Distribution Code Review Panel [DCRP], which will

   I. Add a new column of Declared Supply Voltages to Table 1A, as mandated by EN50160, with values chosen such that the maximum and minimum voltages per Planning Standards, will be within +/- 1.1 pu of these values
   II. Add a clarifying statement to the effect that all references to voltage in Connection Network Codes relate to the Declared Supply Voltages.

It should be noted that this indication of intent at the time of writing, does not, in and of itself guarantee that the proposal will ultimately be recommended by the DCRP or approved by CRU.

5. Proposals

This section covers the proposals for the non-exhaustive parameter selection and non-mandatory requirement selection. The document is laid out by theme, and in some cases further broken down into subtheme for clarity. The four main themes are:

4.1 Frequency

4.2 Voltage including Fault Ride Through

4.3 System Restoration

4.4 Protection and Instrumentation

Each section includes the Article number and the topic being discussed. A brief description of the requirement is provided alongside a table of the items being proposed and a justification is provided where required. Any industry submissions received on the consultation received on a topic are included with the SO response to the submission.

The tables contain:

- A description of the parameter or requirement;
- The RfG allowable range or an indication that a parameter needs to be specified by the RSO;
- The proposal for the parameter or requirement;
- The RfG Article reference;
- A list of the generator types that this applies to and
- A justification code.

Please note that anything highlighted in blue text signifies a new proposal and required justification since the Consultation Document was issued. Were relevant we have also added 'post consultation notes' as required.

Justification Codes

The justification codes identify which of three categories the proposed parameters falls into. For category 1 further rationale is only provided where it is felt it is required to aid understanding. If a proposal falls into category 2 or 3; an explanation is provided.

1. "In line with existing"
   The proposed parameter is in line with existing Grid or Distribution Code requirements.

2. "As close as possible to the existing"
   The existing Grid or Distribution Code requirements do not fit within the allowable RfG range. In this case the proposed parameter is as close to the existing Grid or Distribution Code requirements as is allowable under RfG

3. "New of Different"
   The requirement either does not exist in our Grid and Distribution Codes today and a rationale for the selection is provided. In some cases we have the requirement today but we are proposing a different value and a rationale is provided for this choice

4. "N/A"

Please note that in some tables we have also shown mandatory and/or exhaustive parameters to provide context to the non-exhaustive or non-mandatory parameter. These items are in greyed out cells and do not form a part of this proposal document as the item is mandatory and exhaustive in RfG and we do not have the right to change them.

5.1 Frequency Theme

The non-exhaustive and non-mandatory frequency parameters in RfG cover a number of different requirements. The following sub-themes are discussed in the following sections:

- Frequency ranges
- Rate of Change of Frequency (RoCoF) withstand capability
- Automatic connection to the network
- Active Power Control
    - Admissible Active Power reduction from maximum output with falling frequency
    - Remote operation of facility to cease active power
    - Achieving Active Power Set-points
- Frequency Modes
    - Limited Frequency Sensitive Mode: Over-frequency (LFSM)-O
    - Limited Frequency Sensitive Mode: Under-frequency (LFSM)-U
    - Frequency Sensitive Mode (FSM)

5.1.1 Frequency ranges

5.1.1.1 Article 13.1 (a) (i): Frequency Ranges

Non-Exhaustive Parameter Selection

Applies to Type A, B, C, D PGMs and Offshore PPMs

Requirement

A power-generating module shall be capable of remaining connected to the network and operate within the frequency ranges and time periods specified in the table below. Please note that only the item in bold is a non-exhaustive parameter and therefore subject to approval. The other parameters are provided for context.

Proposal

Parameter	Parameter in RfG	Proposal	Article Number	Type Applicability	Justification Code
Frequency Ranges	*47,5 Hz-48,5 Hz for 90 minutes*	*Mandatory*	*13.1.a.(i)*	*A, B, C, D PGMs and Offshore PPMs*	*N/A*
Frequency Ranges	48,5 Hz-49,0 Hz for a time to be specified by each TSO, but not less than 90 minutes	90 Minutes	13.1.a.(i)	*A, B, C, D PGMs and Offshore PPMs*	2
Frequency Ranges	*49,0 Hz-51,0 Hz for an unlimited time*	*Mandatory*	*13.1.a.(i)*	*A, B, C, D PGMs and Offshore PPMs*	*N/A*
Frequency Ranges	*51,0 Hz-51,5 Hz for 90 minutes*	*Mandatory*	*13.1.a.(i)*	*A, B, C, D PGMs and Offshore PPMs*	*N/A*

Table 2 Frequency Withstand Time Periods

Justification

The RfG states that the operation time in the frequency range of 48.5 – 49.0 Hz shall be specified by the TSO but not less than 90 minutes. The current Grid Code requirement in this frequency range is 60 minutes. The proposed parameter of 90 minutes is the closest allowable to the current Grid Code requirement. Please note the Grid Code in Ireland also requires power-generating modules to remain connected to the network as follows

- between 47-47.5 Hz for 20 seconds
- and between 51.5 -52 Hz for 60 minutes

These requirements will remain in the Grid Code in addition to the RfG requirements in the table above.

Post Consultation Note

Article 13 1.(a) (ii) and (iii) explains how wider ranges etc. can be applied to preserve or to restore system security. The ENTSO-E ENTSO-E IGD on frequency ranges states that agreements must focus on wider withstand capabilities than those specified in Article 13(1)(a)(ii) for countries or areas that have higher risk for example under system split conditions. EirGrid has chosen to deal with such requirements in a transparent manner well in advance of grid connection to ensure those wishing to connect are fully aware of such system requirements at an early stage.

Consultation Submissions

Submission 1

One respondent noted that the extended frequency ranges above require 60 minutes withstand capability which is longer than the GB timeframe of 15 minutes and therefore beyond the RfG requirements. They commented that extended frequency ranges are not binding but are agreed by Power Generating Facilities as per Article 13 and per the ENTSO-E IGD on frequency ranges.

SO Comments

Our proposal is to retain the frequency requirements in the ranges of 47.0 - 47.5 Hz and 51.5 - 52.0 Hz as detailed in the Grid Code. While we acknowledge that these requirements exceed the RfG frequency ranges requirements, these are existing Grid Code requirements and are essential for the operational security of the Transmission System. The two bullet points in 4.1.1.1 of the proposal explain that the current EirGrid Grid Code specifies frequency ranges and required connection times outside the range of RfG Network Code. Article 13 1 (a) (ii) and (iii) explains how wider ranges etc. can be applied to preserve or to restore system security.

The ENTSO-E ENTSO-E IGD on frequency ranges states that agreements must focus on wider withstand capabilities than those specified in Article 13(1)(a)(ii) for countries or areas that have higher risk for example under system split conditions. EirGrid has chosen to deal with such requirements in a transparent manner well in advance of grid connection to ensure those wishing to connect are fully aware of such system requirements.

Submission 2

One respondent commented with an additional note on Cogeneration/PGM embedded in industrial site. RfG Article 6.3 states that Power generating modules on an industrial site have the right to agree on requirements for disconnection from the Grid in order to preserve the industrial process. This needs to be captured in the Grid Code. Furthermore, the extended frequency ranges cannot be included in the Grid Code, as they are not foreseen by the RfG.

SO Comments

As RfG Network Code doesn't not specify requirements for frequencies of 47.0 - 47.5 Hz and 51.5 - 52.0 Hz, TSOs may specify requirements for these frequency ranges, if required, for the secure operation of their Transmission System.

While we acknowledge that the frequency requirements within the ranges of 47.0 - 47.5 Hz and 51.5 - 52.0 Hz are in addition to the requirements stated in the RfG, they are existing requirements in the Grid Code and are essential for the security of the Transmission System.
The Irish transmission is quite small with very little interconnection. As such it is far more likely to be susceptible to these extremes of frequency than the larger European transmission grids.
The removal or reduction of these frequency requirements would reduce the overall ability of the Transmission System to withstand a severe frequency event. As such, we are proposing the retention of these requirements for all PGMs.

Submission 3

One respondent commented that the proposed withstand capability is an increase from 60 min in current Grid Code.

SO Comments

Comment noted, however, the TSO has selected the minimum time in the range allowed under the RfG.

5.1.2 Rate of Change of Frequency

5.1.2.1 Article 13.1 (b): RoCoF

Non-Exhaustive Parameter Selection

Applies to Type A, B, C and D PGMs and Offshore PPMs

Requirement

With regard to the rate of change of frequency withstand capability, a power-generating module shall be capable of staying connected to the network and operate at rates of change of frequency up to a value specified by the relevant TSO, unless disconnection was triggered by rate-of-change-of-frequency-type loss of mains protection. The relevant system operator, in coordination with the relevant TSO, shall specify this rate-of-change-of-frequency-type loss of mains protection.

Proposal: RoCoF Withstand Capability

Parameter	Parameter in RfG	Proposal	Article Number	Type Applicability	Justification Code
The maximum RoCoF for which the Power Generating Module (PGM) shall stay connected	Not Specified	1 Hz/s over 500ms window	13.1.b	A, B, C and D PGMs & Offshore PPMs	1

Table 3 Rate-of-change-of-frequency-type loss of mains protection

Justification: RoCoF Withstand Capability

The proposal is to maintain the ‘agreed in principal’ Grid Code standard for RoCoF of 1 Hz/s over a 500 ms window. It is proposed to review the Ireland RoCoF requirement of 1 Hz/s as part of the three year review

Consultation Submissions:

Submission 1

One respondent commented that it is not clear how the 1Hz/s over 500ms is to be measured.

SO Comments
The methodology for the measurement of the 1 Hz/s over 500 ms will be identified as part of the implementation phase of the RfG.

Submission 2

One respondent asked whether a guarantee of compliance will be enough to prove compliance. It is stated that many asynchronous generators can meet in excess of the requirement but are unaware of how to prove compliance.

SO Comments

For Transmission Connected generators a guarantee from the generator will not suffice as evidence of compliance.

At the moment, compliance is verified by the following:

- review of settings
- provision of the necessary studies
- Grid Code Compliance Testing via frequency step injection

The proposal is to maintain these compliance requirements.

For Distribution Connected generators, the tools for performance monitoring have not yet been defined or agreed.

Submission 3

One respondent commented that they would be concerned about the ability of Loss of Mains projection to detect true loss of mains events for SPGMs operating in trickle import scenarios if a setting of 1Hz/sec over 500ms was selected. They commented that RoCoF protection relays set at 1Hz/sec over 500ms can fail to detect loss of mains events during dynamic testing, which would be similar in nature to localised loss of mains events. And while this RoCoF setting of 1Hz/sec over 500ms is being specified for Types C & D PGM's in the RfG Network Code's it is also being applied to a more numerous quantity of Type B's in this jurisdiction. We would ask what consideration is being given to this situation.

SO Comments

The concerns are noted however, for the topologies and circumstances referred to, the DSO are not changing the RoCoF setting, for the very reasons mentioned in the justification section above.

Proposal: Loss of Mains Protection [Transmission Connected]

Parameter	Parameter in RfG	Proposal	Article Number	Type Applicability	Justification Code
The proposal for loss of mains protection [Transmission Connected]	Not Specified	is 1 Hz/s over 500ms window	13.1.b	D PGMs and Offshore PPMs	1

Table 4 Rate-of-change-of-frequency-type loss of mains protection [Transmission Connected]

Justification: Loss of Mains Protection [Transmission Connected]

The proposal is to maintain the existing protection settings for transmission connected PGMs which is 1 Hz/s over a 500ms window.

Consultation Submissions:

Submission 1

One respondent asked for clarification of RoCoF protection settings with respect to RoCoF withstand capability. They would like to know why they are the same and in which circumstances a transmission connected power generating unit would require loss of mains protection.

SO Comments

Currently, PGMS need to have a capability of withstanding at least 1 Hz/sec over a 500 ms window. Currently transmission connected units are not required to be equipped with RoCoF protection.

Should such protection be employed, it shall be set to greater than 1 Hz/sec.

Submission 2

One respondent suggested that the proposal should state: "greater than 1Hz/s…" so as not to not overlap

SO Comments

Currently, PGMs need to have a capability of withstanding at least 1 Hz/sec over a 500 ms window. Currently transmission connected units are not required to be equipped with RoCoF protection.

Should such protection be employed, it shall be set to greater than 1 Hz/sec.

Submission 4

One respondent commented that they could only support the proposal if there is no fast 3-phase reclosing sequence or the fast reclosing sequence is foreseen with a reasonably longer delay time, otherwise out-of-phase reclosing could happen and this can damage the synchronous generator. There is a further comment that the proposal for 500ms is too long a time period for power generating modules associated with an industrial process. It is also suggested that in the case of power generating modules associated with an industrial process the loss of main shall be based in this case on circuit breaker positioning or df/dt shall trip in a much shorter time. The second option is to have an alternative logic combination of voltage and frequency protection function shall be adopted to detect separation from the grid

SO Comments

The RoCoF protection setting complements the in principle Grid Code modifications requirements for withstand capability and we feel that the proposal above is appropriate if or when this Loss of Mains protection requirement is rolled out to Transmission connected PGMs.

We expect the relevant transmission connected PGMs to manage their own processes, whilst respecting these requirements.

Proposal: Loss of Mains Protection [Distribution Connected]

<table>
<tr><th rowspan="3">Parameter</th><th rowspan="3">Parameter in RfG</th><th colspan="4">Proposal</th><th rowspan="3">Article Number</th><th rowspan="3">Type Applicability</th><th rowspan="3">Justification Code</th></tr>
<tr><th colspan="4">Positive and Negative RoCoF</th></tr>
<tr><th colspan="2">Generator Category</th><th>Pick Up</th><th>Time Delay</th></tr>
<tr><td rowspan="3">The proposal for loss of mains protection [Distribution Connected]</td><td rowspan="3">Not Specified</td><td colspan="2">DFIG / Full Converter Generator</td><td>2 Hz/s</td><td>0.3s</td><td rowspan="3">13.1.b</td><td rowspan="3">A, B, C and D PGMs and Offshore PPMs</td><td rowspan="3">1</td></tr>
<tr><td>Synchronous Generator / Directly Connected Induction Generator</td><td>H > 3 MWs /MVA</td><td>0.6 Hz/s</td><td>0.6s</td></tr>
<tr><td>Synchronous Generator / Directly Connected Induction Generator</td><td>H ≤ 3 MWs /MVA</td><td>1.0 Hz/s</td><td>0.6s</td></tr>
</table>

Table 5 Rate-of-change-of-frequency-type loss of mains protection

Justification: RoCoF Protection settings [Distribution connected]

RoCoF settings were originally stated as 0.4 Hz/s in the 2003 *"Conditions Governing*[10]*"* document. In 2012 a newer version of the Conditions Governing document removed this value and advised that settings would be provided upon request to ESBN. Connection requests and witness testing have been based on revised settings since then. The basis for the revised settings was a study carried out by consultants for ESBN. This study looked at sensitivity to the detection of islanding. The outcome is that low inertia machines could have a setting consistent with the higher withstand capability and only high inertia (>3 MWs/MVA) synchronous machines would need a lower (0.6 Hz/s) setting. This would enable the majority of wind generators and small scale generators to comply with Distribution Code RoCoF withstand requirements of 1 Hz/s for 500ms.

The next version of the Conditions Governing document will have these values specifically included.

[10] *"Conditions Governing Connection to the Distribution System:*
- *Connections at MV and 38 kV*
- *Embedded Generators at LV, MV and 38 kV"*

Consultation Submissions:

Submission 1

One respondent commented that 300ms is very short to give an accurate reading. It is commented that it is possible to have 1Hz/s for 500ms but not 2Hz/s for 300ms as this means that transmission level LoM Protection will activate while distribution level will remain connected which can cause further issues.

SO comments

These are existing settings, which were arrived at, having carried out sensitivity studies for local island detection. There is no intention to change them.

Submission 2

One respondent commented that they could only support the proposal if there is no fast 3-phase reclosing sequence or the fast reclosing sequence is foreseen with a reasonably longer delay time, otherwise out-of-phase reclosing could happen and this can damage synchronous generator. There is a further comment that the proposal for 500ms is too long a time period for power generating modules associated with an industrial process. It is suggested that either

It is also suggested that in the case of power generating modules associated with an industrial process the loss of main shall be based in this case on circuit breaker positioning or df/dt shall trip in a much shorter time. The second option is to have an alternative logic combination of voltage and frequency protection function shall be adopted to detect separation from the grid

SO Comments

On the first point, ESBN reclosing and dead times, where applied, are co-ordinated with the longest clearance times associated with the network protection.

There has been significant engagement with industry and OEMs on the implementation of the TSO-DSO RoCoF workstream, for non-wind, non-exporting sites. Such things as topology and CB location continue to feature in these discussions.

5.1.3 Active Power Control

5.1.3.1 Article 13.4.a: Admissible reduction from maximum output with falling frequency

Non-Exhaustive Parameter Selection

Applies to Type A, B, C and D PGMs and Offshore PPMs

Requirement

The relevant TSO shall specify admissible active power reduction from maximum output with falling frequency in its control area as a rate of reduction falling within the boundaries, illustrated by the full lines in Figure 1 below.

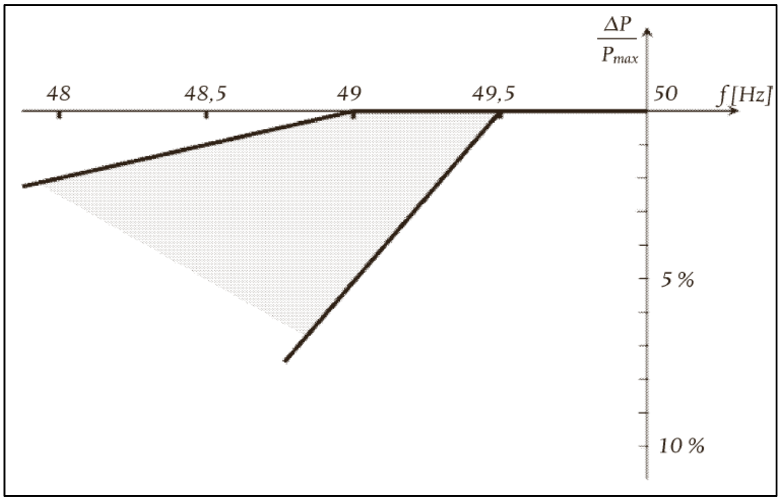


Figure 1 Maximum Power Capability Reduction with Falling Frequency

Proposal

Parameter	Parameter in RfG	Proposal	Article Number	Type Applicability	Justifi Co
Admissible active power reduction from maximum output with falling frequency	below 49 Hz falling by a reduction rate of 2% of the maximum capacity at 50 Hz per 1 Hz frequency drop **<u>or</u>** Below 49.5 Hz falling by a reduction rate of 10% of the maximum capacity at 50 Hz per 1 Hz frequency drop.	For transient domain: below 49 Hz falling by a reduction rate of 2% of the maximum capacity at 50 Hz per 1 Hz frequency drop For steady state domain: Below 49.5 Hz, falling by a reduction rate of 2% of the maximum capacity at 50 Hz per 1 Hz frequency drop	13.4 (a)	A, B, C and D PGMs and Offshore PPMs	3

Table 6 Admissible active power reduction from maximum output with falling frequency

Justification: Transient Response

For the transient domain:

As the system frequency decreases, it is essential that any reduction in generation output is minimised, in order to prevent the frequency from falling any further. The current proposal is to allow a maximum decrease in generation output of 2% when the frequency is below 49 Hz, and whilst this is the most arduous parameter allowable under the RfG, it lessens any further reduction in the system frequency by minimising the reduction in the generation MW output, which allows time for frequency response measures to be activated and ultimately the system frequency to stabilise.

Justification: Static Response

For the steady state domain:

As described above for transient domain - with all under frequency events, it is essential to minimize any further reduction in the generation MW output in order to stabilize the system frequency as quickly as possible. The proposal of 2% of maximum capacity at 50 Hz per 1 Hz frequency drop when the frequency is below 49.5 Hz, while being quite arduous, minimizing any further reduction in the generation MW output, and is in line with the IDG document "Maximum Admissible active power reduction at low frequencies".

Consultation Submissions:

Submission 1

Two respondents commented that the proposed value is very small value for certain technologies such as gas engines. They would propose to align the proposal with other European countries and increase the value to for example 6%Pn/Hz or 10%Pn/Hz. They recommended that the SOs would follow the new Implementation Guidance document on Maximum admissible active power reduction at low frequencies. They suggest that the value chosen should be compared to Gas Turbine O&M speed/power/temp performance curves.

Another respondent similarly commented that they think this is a very small value for certain technologies, so they would also propose to align it with other European countries and increase it to for example either 6%P_n/Hz or 10%P_n/Hz.

Another respondent similarly commented that for internal combustion engines of synchronous generators, a 2% reduction in active power after 49 Hz is very stringent. The implementation guideline document on active power reduction at low frequencies suggests the above argument. They suggest a 10 % P_n/Hz reduction after 49 Hz is recommended.

SO Comments

The reduction rate of 2% of the maximum capacity at 50 Hz per 1 Hz frequency drop is in alignment with the ENTSO-E ENTSO-E IGD. On page 7 section 2) it states it would make sense to have different requirement's for different synchronous areas, i.e. UK, IE = 2%/Hz. At frequencies above 49Hz a drop in active power output is not permitted. The choice of this value improves frequency stability and improves security of supply on the Island of Ireland.

ENTSO-E held open consultations on the requirements of the RfG and all stakeholders were able to comment on the proposals within RfG. The RfG requirements have now been finalised at European level with the exception of the national implementation decisions.

It was felt that the new generation of CCGTs would be capable of complying with this requirement.

<u>*Submission 2*</u>

One respondent requested further clarification on the maximum capacity in the context of the primary energy source (e.g. wind).

SO Comments

Max capacity is defined in the RfG as is the maximum continuous active power which a power-generating module can produce, less any demand associated solely with facilitating the operation of that power-generating module and not fed into the network as specified in the connection agreement or as agreed between the relevant system operator and power-generating facility owner.

Grid Code requirements were previously based on registered capacity, which is the minimum of installed capacity and MEC. Requirements will now be based on the maximum capacity as per the above definition.

As detailed in the IDG "Maximum Admissible active power reduction at low frequencies" dated 31/01/2018, under the Technology characteristics, wind farms based on full converter technology have very limited reduction of active power at low frequencies. Any reduction in active power is mainly due to impact of the low frequency on the wind farm's auxiliary equipment and/or change of losses in the step – up transformers.

Similarly, DFIG based wind farms do not need to reduce their active power at low frequency to compensate for the increase of current related to the decrease in frequency.

Hence, it is envisaged that wind farms should be fully capable of complying with the most arduous requirements allowable under the RfG.

<u>*Submission 3*</u>

One respondent commented that a gas turbine technology output at falling frequency neither is non-linear nor can be controlled since intrinsic to the generating unit itself. The 49 Hz, 2% power drop at the specified ambient conditions is not a realistic characteristic for any gas turbine, regardless of whether the technology is single or multi shaft. They commented that EUTurbines have been presenting examples and explanations including the characteristics, of GT technology since 2012. The proposals presented here exceed the presentations from EUTurbines. They also comment that every gas turbine has its own characteristics. They suggest that a possible approach is to leave the characteristic as defined in the proposals and to request GT manufacturer to provide expected power deviation function of ambient temperature.

SO Comments

ENTSO-E held open consultations on the requirements of the RfG and all stakeholders were able to comment on the proposals within RfG. The RfG requirements have now been finalised at European level with the exception of the national implementation decisions.

In Ireland, the current Grid Code does not allow for any reduction in output with falling frequency. It is our concern that such reduction in the output of a PGM during a low frequency event would lead to a further reduction in frequency, and pose a serious risk to the system security.

As previous stated, the Irish Transmission System is a very small Transmission System with very limited interconnection. The tripping of a single PGM (CCGT) can result in far larger deviations in system frequency than would be seen on the European system for units of a similar size. As such, any further reduction in the output of the remaining PPM would result in an additional reduction in the system frequency, further reducing the overall system frequency stability.

Furthermore, post consultation and following further clarification from ENTSO-E in the form of the IDG “Maximum Admissible active power reduction at low frequencies” dated 31/01/2018, the initial proposal has been revised to the following:

- For transient domain:
    - below 49 Hz falling by a reduction rate of 2% of the maximum capacity at 50 Hz per 1 Hz frequency drop
- For steady state domain:
    - Below 49.5 Hz, falling by a reduction rate of 2% of the maximum capacity at 50 Hz per 1 Hz frequency drop

This new proposal reduces the steady state domain requirements for PGMs, in comparison to the initial proposal.

Following consultation with OEMs at European level, the limits proposed under the RfG Network Code were deemed to be achievable.

Submission 4

One respondent requested clarification as the justification states 'Other generation units should not require a reduction with falling frequency.' They would like to know does this mean that 4.1.3.1 applies to gas units’ only.

SO Comments

Referring to the ENTSO-E IGD “Maximum Admissible active power reduction at low frequencies” dated 31/01/2018, while it noted that the this requirements is applicable to all PGMs, as stated in Section 2 page 10, Wind farms with either full converter or DFIG should not need to reduce their active power output while frequencies remain the frequency ranges as stated in Article 13(1).

5.1.3.2 Article 13.5: Admissible reduction from maximum output with falling frequency taking Account of Technical Capabilities of PGMs

Non-Exhaustive Parameter Selection

Applies to Type A, B, C and D PGMs

Requirement

The admissible active power reduction from maximum output shall: (a) clearly specify the ambient conditions applicable; (b) take account of the technical capabilities of power-generating modules.

Proposal

Parameter	Parameter in RfG	Proposal	Article Number	Type Applicability	Justification Code
Ambient Conditions	Not Specified	10°C, 70% relative humidity and 1013 hPa.	13.5	Gas-fired SPGMs (A, B, C and D).	3

Table 7 Admissible active power reduction from maximum output

Justification

The RfG allows the TSO to specify ambient conditions applicable. The current version of the Grid Code states, under the definition of registered capacity, that the standard ambient conditions for the measurement of registered capacity will be 10°C, 70 % relative humidity and 1013 hPa. As the RfG allows the TSO to specify the applicable ambient conditions, it is proposed to continue to use these ambient conditions requirements. The ENTSO-E guidance document for national implementation for network codes on grid connection (Implementation Guidelines Documents) highlights that the need for this requirement is driven by the characteristics of gas fired generation units. Other generation units should not require a reduction with falling frequency. For this reason it is proposed to limit the application of this clause to gas fired generation units.

Consultation Submissions

<u>Submission 1</u>

One respondent requested clarification whether the specified performance applies up to 10degC only and do not apply at higher temperatures; or it applies under this particular ambient conditions only and no definite requirements otherwise.

SO Comments

As per the ENTSO-E IGD “Maximum Admissible active power reduction at low frequencies” dated 31/01/2018, the PGM should provide the characteristic expected over a full temperature range (eg-10oC - 40oC) the performance specified under Article 13.5 is at 10oC

Submission 2

One respondent commented that Art 13.5 is used for GT unit to complement art 13.4, by providing ambient condition and taking into consideration the technical capabilities of the correspondent technology. They comment that this Article was created to accommodate gas turbine technologies; however the way it was defined is poorly reaching the goal, since every GT performs differently. It is suggested that a possible approach is to leave the characteristic you defined as reference for all and to request GT manufacturer to provide expected power deviation function of ambient temperature. This would fulfill also the 13.5. They noted that; the requirements are only critical at full power for GT characteristic and that the requirement cannot be tested and it doesn’t drive competition.

Any compensative system are risky and someway useless as a collateral effect they can lead to flame out and when employed, they are slow acting logic, not in line with supporting the initial RoCoF. Compensative system brings the risk of flame-out, and as well cannot be tested, which they consider not to be a good trade for the requirements. A respondent suggested again reviewing EUTurbines response on this topic.

SO Comments

As per the ENTSO-E IGD “Maximum Admissible active power reduction at low frequencies” dated 31/01/2018, the PGM should provide the characteristic expected over a full temperature range (eg-10oC - 40oC). The performance specified under Article 13.5 is at 10ºC.

5.1.3.3 Article 13.6: Remote operation of facility to cease active power output

Non-Mandatory Requirement being made Mandatory

Applies to Type A and B PGMs

Requirement

The power-generating module shall be equipped with a logic interface (input port) in order to cease active power output within five seconds following an instruction being received at the input port. The relevant system operator shall have the right to specify requirements for equipment to make this facility operable remotely.

Proposal

Requirement	Requirement in RfG	Proposal	Article Number	Type Applicability	Justification Code
Specify requirements for equipment to make this facility operable remotely for Type A	A right to specify	Maintain the right to specify for Type A only in due time for plant design (c/f Art 14 (2) (b) for Type B	13.6	A and B PGMs	1

Table 8 Specify requirements for equipment to make this facility operable remotely for Type A

Justification

The proposal is to maintain the right to specify the requirement for remote control equipment but to advise on a case by case basis, as necessary, taking into consideration that the specific requirements will be dependent on the plant design and compatibility requirements.

The intention of the phrase, ‘in due time for plant design’ is intended to mean during the connection offer phase.

5.1.3.4 Article 13.7: Automatic connection to the network

Non-Exhaustive Parameter Selection

Applies to Type A, B and C PGMs

Requirement

The relevant TSO shall specify the conditions under which a power-generating module is capable of connecting automatically to the network. Those conditions shall include:

(a) Frequency ranges within which an automatic connection is admissible, and a corresponding delay time; and

(b) Maximum admissible gradient of increase in active power output.

Automatic connection is allowed unless specified otherwise by the relevant system operator in coordination with the relevant TSO.

Proposal

Parameter	Parameter in RfG	Proposal	Article Number	Type Applicability	Justification Code
Frequency Ranges and Time Delay	Non-specific	49.8 Hz to 50.2 Hz with a five minute delay	13.7	A, B, and C PGMs	1
Maximum admissible gradient of increase in power	Non-specific	10% of P_{max} per minute	13.7	A, B and C PGMs	3
Allowing automatic connection	A right to not allow	Allow	13.7	A, B and C PGMs	1

Table 9 Conditions under which a PGMs is capable of connecting automatically to the network

Justification: Frequency Ranges and Time Delay [Distribution Connected]

The values exist today for distribution connected generators, as stipulated in Conditions Governing[11]. The proposed frequency range and time delay are per the existing requirements in the Distribution Code.

Justification: Maximum admissible gradient of increase in power

The proposed maximum admissible gradient of increase in power of 10% of the P_{Max} is not currently specified in the existing Distribution Code but it is consistent with the existing Grid Code requirement WFPS1.5.4.1 which states that deviations in the ramp rates will not exceed 3%.

[11] *"Conditions Governing Connection to the Distribution System: • Connections at MV and 38 kV Embedded Generators at LV, MV and 38 kV"*

Post Consultation Note

3% was incorrectly referenced in the section "Justification: Maximum admissible gradient of increase in power". This has been corrected to 10% to align with the actual value proposed in Table 9 above.

Consultation Submissions: Frequency Ranges and Time Delay

Submission 1

One respondent commented that the five minute delay time is a new requirement and is not clear how this fits with the maximum of 3 mins response time when coming out of pause state as required in 15.2(a) for type C's

SO Comments

Article 15(2)(a) does not specifically refer to a "pause state". Article 15(2)(a) refers to controllability. Article 13(7) refers to automatic connection following conditions when frequencies are outside specified ranges. Conditions Governing Connection to the Distribution System already specified that frequency and voltage must be within limits for 5 minutes prior to automatic reconnection.

Submission 2

One respondent requested clarification on why a 5 minute delay is proposed in the Ireland consultation and a 3 minute delay is proposed for Northern Ireland.

SO Comments

This is aligned with our current policy for reconnection/automatic connection as set down in the Conditions Governing Connection to the Distribution System. No change from existing practice.

The harmonisation of the two existing Grid Code would a very significant body of work and would involve the identification, assessment, determination and harmonisation of a large number of requirements and parameters which are not within the remit of the Network Codes. As such, it was decided that it would not be the optimum solution to combine the implementation of the Network Codes with the potential harmonisation of the existing Grid Codes.

Consultation Submissions: Maximum admissible gradient of increase in power

Submission 1

One respondent commented that normally it is 20% (default) for WFRR or APCRR or as fast as possible if outside the frequency deadband. They requested clarification on the following scenario: What if frequency control is ON and in curve 1 and APC ON and the frequency drop from above 52Hz to something between the 0,015Hz deadband and 50,2Hz? Frequency control tests 8.3 Step 14 states that the ramp rate shall be at the maximum possible rate?"

SO Comments

For frequencies above 52.0 Hz, PGMs are not required to stay synchronized.

Once, the frequency goes outside the frequency deadband in the example given (0.015 Hz), the ramp rate shall be at the maximum ramp rate.

<u>Submission 2</u>

One respondent requested clarification as the justification mentions 3% value whilst 10% is proposed in the table.

SO Comments

This was a typo. 10% was intended.

<u>Submission 3</u>

One respondent commented that 10% per minute may be suitable for Type C PGMs it is an unrealistic value for Type A & B power generating modules. If 10% is introduced it would mean for example that a 20kW Type A PMG would take 10minutes to achieve rated output. They believe a more realistic value for Type A, B & CPMG's should be non-specific and thereby allow OEMs to introduce their own/preferred gradient as they deem necessary. Further, as part of the DS3 Services are EirGrid not seeking to have Generators on-line and at rated output within 90 seconds?

SO Comments

The reason for the 10% per minute limit is to keep to normal voltage change within 1% before the tap-changer operates. This is based on the design voltage drop from a trip at 100% load to 0% load of 10% voltage, which implies a 10% load change give a 1% voltage change. The tap-changer operates with a one minute time delay.

The System Services out of scope

5.1.3.5 Article 14.2.b: Remote operation of power output

Non-Mandatory Requirement being made Mandatory

Applies to Type B PGMs

Requirement

Type B PGMs shall fulfil the following requirements in relation to frequency stability:

> *(a) to control active power output, the power-generating module shall be equipped with an interface (input port) in order to be able to reduce active power output following an instruction at the input port; and*
>
> *(b) the relevant system operator shall have the right to specify the requirements for further equipment to allow active power output to be remotely operated*.

Proposal

Requirement	Requirement in RfG	Proposal	Article Number	Type Applicability	Justification Code
Right to specify the requirements for further equipment to allow active power output to be remotely operated	To specify or not to specify	RSO to specify for Type B generators with a maximum capacity 1 MW and above; in due time for plant design.	14.2 (b)	B PGMs	3

Table 10 Remote operation of Power Output

Justification

The TSO and DSO in Ireland have proposed a modification to the Distribution Code to reduce the threshold of controllability of generation units from 5 MW to 1 MW. This is being progressed through the Distribution Code Review Panel. This RfG proposal is in line with that proposal and ensures the DSO can specify equipment to allow active power output to be remotely operated.

Consultation Submissions:

Submission 1

One respondent commented that prioritisation should be defined for the different logics when considering cogeneration plant. They recommend that the SOs would have specific agreement with generating plant where industrial facilities are depending on heat demand.

SO Comments

This issue is dealt with in the RfG in Article 6 - please see the RfG for full details.

Submission 2

One respondent commented that the specification of the equipment by the SO should a collaborative process with industry and should be proposed through the forum of the DCRP and require the consent of all members to approve.

SO Comments

The Respondent is correct in stating that the DCRP and its workings may well be involved in a high level decision to invoke this requirement for a given class or cohort of generators. However, there is a level of detail beyond which the Distribution Code is not the appropriate vehicle to disseminate information, some of which may be site specific.

5.1.3.6 Article 15.2.a: Achieving Active Power Set points

Non-Exhaustive Parameter Selection

Applies to Types C and D PGMs

Requirements

… power-generating modules shall fulfil the following requirements relating to frequency stability:

(a) With regard to active power controllability and control range, the power-generating module control system shall be capable of adjusting an active power set point in line with instructions given to the power-generating facility owner by the relevant system operator or the relevant TSO.

The relevant system operator or 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 set point and the time within which it must be reached;

Proposal

Parameter	Parameter in RfG	Proposal	Article Number	Type Applicability	Justification Code
The period within which the adjusted active power setpoint must be reached	No range provided	10 seconds response time plus the ramp rate for the unit. NB where wind turbines have to be turned on to achieve the set point then a maximum of 3 minutes response time is allowed.	15.2 (a)	C and D PGMs	1
Tolerance (subject to the availability of the prime mover resource) applying to the new setpoint and the time within which it must be reached	No Range Provided	For PGMs, the maximum of 1 MW or 1% of dispatch quantity is applied. For PPMs, the maximum of +/- 3% of registered capacity or +/- 0.5 MW.	15.2 (a)	C and D PGMs	3

Table 11: Achieving Active Power Set-points

Justification

The ramp rate referred to in this table is the Active Power Control Set-Point Ramp Rate as defined in the Grid Code and advised to the generator 120 business days in advance of commissioning.

The proposed Tolerance limits are as per the current operational and market monitoring tolerances. By aligning the tolerance for RfG with the current practices, it will ensure the monitoring and assessment of active power set point is consistent for all PGMs and PPMs.

Notes: In the context of paragraph (b) we interpret this section to apply to remotely controlled generation units where the set point is issued directly to the control system of the unit and does not apply to generation units where a dispatch instruction is issued from the TSO to an operator to implement. The Grid Code provides for both situations in section SDC2.4.2.12 for CDGUs and in Section WFPS1.5.2.1 for PPMs. The PPM requirement is that the unit starts to respond within 10 seconds of receiving the instruction hence the period within which the adjusted active power set point must be reached is 10 seconds plus the ramp rate.

Consultation Submissions: The period within which the adjusted active power set point must be reached

Submission 1

One respondent commented that it is slightly unclear. Is the intention to allow WFPS 3 minutes to begin generating then follow the required ramp rate?

SO Comments

Yes, the intention is that a wind farm will have 3 minutes to turn on their turbines, after which the wind farm should increase its output in accordance with its ramp rate.

Submission 2

One respondent requested clarification in relation to how this 3 minute requirement fits with the above Article 13.7 requiring minimum 5mins?

SO Comments

This is broken down into 5 minutes of normal system conditions before automatic reconnection is permitted, followed by 3 minutes to restart wind turbines and then the normal ramp rate.

Submission 3

One respondent commented that they agree in principle with the proposals. They requested a clarification stating "10 seconds response time plus time to reach set point corresponding to the ramp rate for the unit." They did comment that this may be problematic for wind turbines that need time to yaw into the wind after a period of extended shutdown.

SO Comments

In the case where a wind farm has to turn on wind turbines, a 3 minute response time will apply. After which the wind farm must increase its output in accordance with its ramp rate.

Submission 4

One respondent commented that the maximum ramp rate of a unit should be taken into account when defining the time period in which the unit has to reach the desired operation point. They proposed two solutions that the SO to either propose a minimum ramp rate (NOT MORE THAN 0.5%Pn/s) or add a comment on “limited by the units maximum allowed power ramp rate”.

SO Comments

The SOs have updated the proposal to include the following sentence “10 seconds response time plus the ramp rate for the unit.

Consultation Submissions: Tolerance (subject to the availability of the prime mover resource) applying to the new set point and the time within which it must be reached

Submission 1

One respondent commented that the 1MW or 1 % accuracy dispatch would require further discussion with all PGMs technology.

SO Comments

This is already the current practice. It is currently possible to achieve these requirements regardless of PGM type.

While we are not currently aware of a PGM type to which these requirements cannot be applied, we are conscience that PGM technology is constantly evolving, and as such these requirements and the ability to apply these requirements to different PGM types are reviewed on an ongoing basis. This review includes discussion with the relevant OEMs, etc., as required.

Submission 2

One respondent commented that the active power tolerance of 3% all the time may be challenging in the case of a fluctuating resource. They requested that the SOs would consider setting limits based on suitable averaging period for example 10 seconds, 1 min etc. They suggested that further discussion with OEMs be carried out.

SO Comments

This is already the current practice. It is currently possible to achieve these requirements regardless of PGM type. We are not currently aware of a PGM type to which these requirements cannot be applied.

While we are not currently aware of PGM type to which these requirements cannot be applied, we are conscience that PGM technology is constantly evolving, and as such these requirements and the ability to apply these requirements to different PGM types are reviewed on an ongoing basis. This review includes discussion with the relevant OEMs, etc., as required.

Submission 3

One respondent commented that commonly active power tolerances for SPGMs are in the range of 5-10 % P_n. They recommend a 5 % P_n tolerance.

SO Comments

A range of 5% tolerance would be a reduction in the level of accuracy compared with the current practices. The proposed parameters are as per current practices. There are no plans to amend or change these practices.

Submission 4

One respondent commented that the words "dispatch quantity" is not defined in the Grid Code revision 6 and they request that this definition be added to the Grid Code. They comment that if this refers to maximum export quantity, the 1% tolerance is an issue for co-generation plant that export no power or limited power to the grid They recommend that the tolerance for these types of sites is applies to the P_n of the generating unit.

SO Comments

The Grid Code and/or Distribution Code will be updated with the relevant definitions and requirements as appropriate. The Grid Code and/or Distribution Code modification will go through the existing process through the Grid Code and/or Distribution Code review panels. In relation to the monitoring of cogeneration sites, these are currently monitored in the same manner as conventional generation sites.

5.1.4 Frequency Modes

5.1.4.1 Frequency Modes Explanation

This section explains the difference between frequency sensitive mode and limited frequency sensitive modes prior to defining the parameters.

Frequency Sensitive Mode:

The vast majority of synchronous generation units, which are currently in operation on the Transmission System today, operate in what is known in the RfG as Frequency Sensitive Mode (FSM). That is, the generation units continuously respond to changes in the system frequency, in accordance with their governor droop characteristics for both increases and decreases in system frequency. This helps maintain the system frequency within the normal operating range.

In RfG parameters relating to the capability of units to operate in FSM must be specified by the TSO and are broken down into two types of parameters – responses required in normal operation and responses required following a step change in frequency.

- In normal operation the parameters to be specified are the % droop and any associated frequency dead bands. There is no parameter relating to the time allowed to achieve the required response. These parameters are consistent with today's Grid Code requirements for normal governor regulation.
- The parameters to be specified to assist with recovering the system frequency following a sudden imbalance and associated frequency step change are a specified % increase in active power relative to the maximum generation of the unit (or available active power for PPMs) within a specified time period (usually seconds). This is similar to today's Grid Code requirements for units to provide operating reserves.

These parameters also apply to PPMs. Under the existing Grid Code PPMs are required to operate in FSM when in active power control mode or when in wind following mode on curve 2. PPMs are not actually acting under the control of a traditional governor. Instead they are moving to MW set points which are calculated in the control system based on measured changes in system frequency. The calculation of the set points is based on a droop characteristics and time for delivery as specified in these FSM parameter settings.

Limited Frequency Sensitive Mode:

When a PGM is operating in Limited Frequency Sensitive Mode (LFSM), the generation unit does not provide any frequency response when the system frequency is within a specified dead band around the nominal frequency. The dead band for LFSM mode is much wider than that specified for FSM mode. FSM dead bands are very small and generally specified to reflect the technical inability of some units to respond to very small changes in frequency and / or to avoid generator hunting.

RfG provides for different LFSM capabilities to be required for over and under frequency events. It should be noted that currently only a very small number of generation units operate in LFSM today. The only generators which act in LFSM mode today are PPMs when in wind following mode and curve 1.

At the moment, it is planned to continue to operate the majority of existing and future PGMs in FSM. However, as the Transmission System evolves and new technology connects, the use of both FSM and LFSM will be assessed on a regular basis.

Summary

For clarity the following table highlights the links between our current frequency control modes and the RfG frequency control modes

RfG Frequency Control Mode	Equivalent Grid Code Frequency Control Mode for PPMs	Equivalent Grid Code Frequency Control Mode for SPGM
LFSM-O	PPM in wind following mode & curve 1	Not applicable in Ireland today
LFSM-U	Not applicable in Ireland today	Not applicable in Ireland today
FSM Normal	PPM in active power set point control mode & curve 1 or curve 2 PPM in wind following mode & curve 2	Normal governor regulation
FSM Frequency Step Change	As above	Operating Reserves

For the avoidance of doubt, relay activated response such as over and under frequency tripping of units or high frequency runback schemes are not covered by this RfG section as they are not related the inherent capability of the unit.

5.1.4.2 Article 13.2.a: LFSM-O Parameter Selection

Non-Exhaustive Parameter Selection

Applies to Type A, B, C and D PGMs and Offshore PPMs

Requirement

With regard to the limited frequency sensitive mode — over frequency (LFSM-O), the following shall apply, as determined by the relevant TSO for its control area in coordination with the TSOs of the same synchronous area to ensure minimal impacts on neighbouring areas:

(a) *the power-generating module shall be capable of activating the provision of active power frequency response at a frequency threshold and droop settings specified by the relevant TSO*;

Proposal

Parameter	Parameter in RfG	Proposal	Article Number	Type Applicability	Justification Code
Frequency threshold	Between 50.2-50.5 Hz	50.2 Hz	13.2(a)	A, B, C and D PGMs & offshore PPMs	1
Droop settings	Between 2-12 %	Machines should be capable of operating in the range 2-12%. The default setting is 4%	13.2(a)	A, B, C and D PGMs & offshore PPMs	1

Table 12: LFSM-O Parameter Selection

Justification:

Frequency Threshold

CC.8.2.1 of the current Grid Code and DPC4.1.1 of the current Distribution Code states that the normal operating frequency range is between 49.8 Hz and 50.2 Hz. Under WFPS 1.5.3.2 and depending on operating mode active power response may not be required when the frequency is within this range. The RfG states that the frequency threshold shall be between 50.2 Hz and 50.5 Hz. Therefore, the existing frequency threshold of 50.2 Hz is allowable under the RfG and will be retained.

Droop Settings

Selected parameters are per as our Grid Code today. The current Grid Code allows for a number of different droop ranges, depending on technology type. However, the default in all cases is a droop setting of 4%, regardless of technology type. By adopting a standard of 4%, as the default, it will ensure compliance with the RfG whilst maintaining a consistent droop setting to all generation types.

A droop parameter is a new requirement in the Distribution Code. The droop setting for distribution connected generators will align with the existing droop settings for transmission connected PGMs.

Consultation Submissions:

Submission 1

One respondent requested further clarification of the frequency modes including diagrams in order to understand how they relate, interact and what performance is proposed.

SO Comments

This will be considered during the Grid Code modification process.

5.1.4.3 Article 13.2.b: LFSM-O: Automatic disconnection and reconnection

Non-Mandatory Requirement being made Mandatory

Applies to Type A PGM

Requirement

(b) *instead of the capability referred to in paragraph (a), the relevant TSO may choose to allow within its control area automatic disconnection and reconnection of power-generating modules of Type A at randomised frequencies, ideally uniformly distributed, above a frequency threshold, as determined by the relevant TSO where it is able to demonstrate to the relevant regulatory authority, and with the cooperation of power-generating facility owners, that this has a limited cross-border impact and maintains the same level of operational security in all system states;*

Proposal

Requirement	Requirement in RfG	Proposal	Article Number	Type Applicability	Justification Code
Automatic disconnection and reconnection of PGMs	Allow or do not allow	Do not allow	13.2 (b)	A PGMs	1

Table 13: LFSM-O Automatic Disconnection & Reconnection

Justification

It is not currently planned to invoke this non-mandatory proposal. However this should not be confused with additional protection settings applied in coordination with the RSO which are agreed on a case by case basis.

Consultation Submissions:

Submission 1

One respondent requested further clarification of the frequency modes including diagrams in order to understand how they relate, interact and what performance is proposed.

SO Comments

This will be considered during the Grid Code modification process.

5.1.4.4 Article 13.2.f: LFSM-O: Actions at minimum regulating level

Non-Mandatory Requirement being made Mandatory

Applies to Type A, B, C and D PGMs and offshore PPMs

Requirement

The relevant TSO may require that upon reaching minimum regulating level, the power-generating module be capable of either:

(i) continuing operation at this level; or

(ii) further decreasing active power output;

Proposal

Requirement	Requirement in RfG	Proposal	Article Number	Type Applicability	Justification Code
Actions in LFSM-O upon reaching minimum regulating level,	Choose between (i) continuing operation at this level; or (ii) further decreasing active power output	(i) continuing operation at this level	13.2 (f)	A, B, C and D PGMs & offshore PPMs	1

Table 14: LFSM-O Actions at Minimum Regulating Level

Justification

Under the current Grid Code and Distribution Code Minimum Load is defined as the minimum MW output a unit can maintain on a continuous basis, whilst providing system services. It is proposed to select option (i) which would maintain the requirements as defined in the current version of the Grid Code.

Consultation Submissions:

Submission 1

One respondent requested further clarification of the frequency modes including diagrams in order to understand how they relate, interact and what performance is proposed.

SO Comments

This will be considered during the Grid Code modification process.

5.1.4.5 Article 15.2.c: LFSM-U Parameter Selection

Non-Exhaustive Parameter Selection

Applies to Type C and D PGMs and offshore PPMs

Requirement

(i) the power generating module shall be capable of activating the provision of active power frequency response at a frequency threshold and with a droop specified by the relevant TSO in coordination with the TSOs of the same synchronous area as follows:

– the frequency threshold specified by the TSO shall be between 49.8 Hz and 49.5 Hz inclusive;

– the droop settings specified by the TSO shall be in the range 2 – 12%.

Proposal

Parameter	Parameter in RfG	Proposal	Article Number	Type Applicability	Justification Code
Frequency threshold	between 49.8 Hz and 49.5 Hz inclusive	49.5 Hz	15.2 (c)	C and D PGMs & offshore PPMs	1
Droop settings	2-12%	Default is 4% unless otherwise specified by the TSO on a site specific basis	15.2 (c)	C and D PGMs & offshore PPMs	1

Table 15 LFSM-U Frequency Threshold & Droop Settings

Justification

Frequency Threshold:

Under the current version of the Grid Code, a Frequency Event occurs when the Transmission System Frequency deviates to a value below 49.5 Hz. The proposal is to retain the existing Grid Code requirements in relation to Frequency Events, by setting the frequency threshold to 49.5 Hz.

Droop Settings:

Selected parameters are as per our Grid Code today. The current Grid Code allows for a number of different droop ranges, depending on technology type. However, the default in all cases is a droop setting of 4%, regardless of technology type. By adopting a default of 4%, as opposed to a range, it will ensure compliance with the RfG whilst maintaining a consistent droop setting to all generation types.

Consultation Submissions:

Submission 1

One respondent requested further clarification of the frequency modes including diagrams in order to understand how they relate, interact and what performance is proposed.

SO Comments

This will be considered during the Grid Code modification process.

5.1.4.6 Article 15.2.d. (i) and (ii): FSM Parameter Selection

Non-Exhaustive Parameter Selection

Applies to Types C and D PGMs and Offshore PPMs

Requirement

(i) *The power-generating module shall be capable of providing active power frequency response in accordance with the parameters specified by each relevant TSO within the ranges shown in Table 4* (as given in the RfG*). In specifying those parameters, the relevant TSO shall take account of the following facts:*
- *In case of over frequency, the active power frequency response is limited by the minimum regulating level,*
- *In case of under frequency, the active power frequency response is limited by maximum capacity,*
- *The actual delivery of active power frequency response depends on the operating and ambient conditions of the power-generating module when this response is triggered, in particular limitations on operation near maximum capacity at low frequencies according to paragraphs 4 and 5 of Article 13 and available primary energy sources;*

(ii) *The frequency response dead band of frequency deviation and droop must be able to be reselected repeatedly;*

Proposal

Parameter	Parameter in RfG	Proposal	Article Number	Type Applicability	Justification Code
Active Power Range (ΔP/Pmax)	1.5-10%	Not proposing a value as this is an error in the RfG Network Code. See note below	15.2 (d) (i) and (ii)	C and D PGMs & offshore PPMs	1
Frequency Response Insensitivity (Δf)	10-30 mHz	15mHz*	15.2 (d) (i) and (ii)	C and D PGMs & offshore PPMs	3
Frequency Response Insensitivity (Δf/f)	0.02-0.06%	0.03%	15.2 (d) (i) and (ii)	C and D PGMs & offshore PPMs	3
Frequency Response deadband	0-500mHz	+/-15mHz*	15.2 (d) (i) and (ii)	C and D PGMs& offshore PPMs	3
Droop	2-12%	Depends on gen type – default is 4%	15.2 (d) (i) and (ii)	C and D PGMs & offshore PPMs	1

Table 16 FSM Parameter Selection

Justification: Active Power Range

The TSO have consulted with the ENTSO-E Frequency Expert Group in relation to FSM. ENSTO-E has confirmed that this parameter was included in the above table as an error and as such was not specified as part of the consultation or this proposal document.

For this reason we are not proposing a value for active power range in table 16.

Post Consultation Note

Following further consultation with ENTSO-E, the TSO will not propose a value for active power range for FSM as this is an error in the RfG Network Code. The TSO will submit the necessary derogation request to the CRU with regard to these requirements in due course. Please see section 4.3 for more details.

Justification: Frequency Response Insensitivity & Frequency Response deadband

The current version of the Grid Code does not distinguish between Frequency Response Insensitivity and Frequency Response deadband.

The Grid Code definition of the Frequency deadband, which is set to +/- 15 mHz, whilst allowing for insensitivity in order to filter out noise, it does not allow for the frequency response of a PGM to be made intentionally unresponsive over any frequency interval.

Hence, it is proposed to retain the current Grid Code requirement of +/-15 mHz by setting a maximum absolute value of 15 mHz for both the Frequency Response Insensitivity and Frequency Response deadband.

*In addition to the individual requirements for Frequency Response Insensitivity (ΔF) and Frequency Response deadband and as per Annex V of the System Operating Guidelines[12] (SOGL), the maximum combined effect of Frequency Response Insensitivity and Frequency Response deadband cannot exceed a value of +/- 15 mHz

Consultation Submissions

Submission 1

One respondent commented that the Final ENTSO-E IGD on frequency modes was published on 31.01.2018 and it provides some clarification on the active power range parameter. They note that this consultation paper states that this parameter is an error in the RfG Code. They suggest that the SOs align this parameter with the latest ENTSO-E IGD and seek further clarification with industry. For instance, GB is proposing a value for "active power range" of 10% of maximum power output.

SO Comments

The TSO have consulted with the ENTSO-E Frequency Expert Group in relation to FSM. ENSTO-E has confirmed that this parameter was included in the above table as an error and as such will not be specified as part of this proposal document.

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[12] http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32017R1485&from=EN

For this reason we are not proposing a value for active power range in table 16.

Submission 1

One respondent commented on the current WFPS testing procedure that requires a DMOL (design minimum operating level) to AAP (available active power) change. They requested clarification on whether this testing requirement will be changed to reflect the Network Codes.

SO Comments

As part of the implementation phase of the network codes, the TSO will develop the necessary testing procedures. This comment will be referred to the testing for consideration.

5.1.4.7 Article 15.2.d. (iii): FSM: Step Change in Frequency

Non-Exhaustive Parameter Selection

Applies to Type C and D PGMs and Offshore PPMs

Requirement

In the event of a frequency step change, the power-generating module shall be capable of activating full active power frequency response, at or above the full line shown in Figure 6 (as given in the RfG) *in accordance with the parameters specified by each TSO (which shall aim at avoiding active power oscillations for the power-generating module) within the ranges given in Table 5* (as given in the RfG)*. The combination of choice of the parameters specified by the TSO shall take possible technology-dependent limitations into account;*

Proposal

Parameter	Parameter in RfG	Proposal	Article Number	Type Applicability	Justification Code
Active power range	1.5-10%	SPGMs: 5% PPMs: 60% in 5 seconds and 100% in 15 seconds	15.2 (d) (iii)	C and D PGMs & offshore PPMs	3
Admissible initial time delay for activation of active power frequency response for PGMs	*2s*	*2s*	*15.2 (d) (iii)*	*C and D PGMs & offshore PPMs*	*N/A*
Admissible initial time delay for activation of active power frequency response for PPMs	Less than 2 seconds	0s No time delays other than those inherent in the design of the frequency response system	15.2 (d) (iii)	C and D PGMs & offshore PPMs	3
Maximum admissible choice of full activation time	30 seconds	5s	15.2 (d) (iii)	C and D PGMs & offshore PPMs	3
Capability relating to the duration of provision of full active power frequency response	15-30 minutes	20min	15.2 (d) (v)	C and D PGMs & offshore PPMs	3

Table 17 Activating full active power frequency response

Justification: Active Power Range

SPGMs

As stated in the previous section, this is primarily based on the need to restore the system frequency as quickly as possible. Consider the example of a drop in frequency to 49.5 Hz. In theory, each PGM on the system should increase their output by ΔP (25%), assuming a 4% droop. However, as each PGM is increasing their output simultaneously, resulting in an increase in frequency, the governor control will reduce ΔP, effectively sharing the burden of restoring the frequency between all of the PGMs in FSM mode. As a result, the output of the PGM will not need to increase by the full ΔP of 25%.

Under the current Grid Code requirements, the same function is provided by Primary Operating Reserve (POR) and Secondary Operating Reserve (SOR). Both of which provide a ΔP of 5%. Hence, it is proposed that the active power range in the RfG will be set to 5%.

PPMs

The current requirements in the Grid Code require a 60% increase in Active Power within 5 seconds and 100% of expected increase (droop response) within 15 seconds of a frequency event. This requirement is core to the achievement of a 40% RES-E target and the ability to operate the system at System Non Synchronous Penetration (SNSP) levels up to 75%. The RfG range in Article 15.2.d only allows us specify a value for the change in power output relative to the Active Power output at the moment the frequency threshold was reached (or the maximum capacity as defined by the TSO) between 1.5-10% i.e. it does not allow us to specify the levels that currently exist in the Grid Code. However to lose the capability provided for in today's Grid Code would be very damaging to the success of the DS3 program and ultimately to the integration of high levels of renewable energy into the power system.

We do not believe that the regulations intentionally undermine this capability and therefore we are going to investigate options to retain todays Grid Code requirements for PPMs.

For the avoidance of doubt, in this consultation we have reflected the permissible ranges in the RfG but respondents should understand that it is our intention to retain the Grid Code requirements for PPMs, in addition to the RfG requirements.

Post Consultation Note

Following further consultation with ENTSO-E, the TSO has proposed the parameters for active power response in line with the current Grid Code requirements. The TSO will submit the necessary derogation request to the CRU with regard to these requirements in due course. Please see section 4.3 for more details.

Justification: Admissible initial time delay for activation of active power frequency response for PPMs

Current version of the Grid Code does not allow for any admissible initial time delays for the activation of active power frequency response, other than those which are inherent in the design of the Frequency Response System (WFPS1.5.3.9). It is proposed that the current requirement should be maintained under the RfG by setting the admissible initial time delay for the activation of active power frequency response for PPMs to 0 seconds.

Justification: Maximum admissible choice of full activation time

As stated above in the justification for the active power range, today the active power capability for FSM is provided by primary and secondary operating reserves (POR and SOR). Under the current requirements for POR and SOR, these reserves must be provided within 5 seconds. Hence, it is proposed to retain this requirement under the RfG by setting Maximum Admissible Choice of Full Activation time to 5 seconds.

Justification: Capability relating to duration of provision of full active power frequency response

The Frequency Containment Reserves (FCR) must remain in place until such time that the Frequency Replacement Reserves are available. In the case of Ireland, the FCR equates to the POR, SOR, TOR1 and TOR2 under the Grid Code. The existing Grid Code requires operating reserves to be in place for up to 20 minutes. Replacement reserves cover the period from 20 minutes to four hours after the event. By proposing a maximum admissible choice of full activation time of 20 minutes, this aligns the Grid Code Replacement Reserves requirements with the RfG Frequency Replacement Reserve Requirements.

Consultation Submissions: Active Power Range

Submission 1

One respondent requested that the SOs would define and clarify what 100% of a multiple-unit power plant is. They also suggested that the requirements shall be proposed on an equality principle, it's recommended to harmonize those parameters at synchronous area level between EirGrid/ESB networks and SONI/NIE network.

SO Comments

Maximum capacity (100%) is defined in the RfG as the maximum continuous active power which a power-generating module can produce, less any demand associated solely with facilitating the operation of that power-generating module and not fed into the network as specified in the connection agreement or as agreed between the relevant system operator and power-generating facility owner.

The harmonisation of the two existing Grid Code would a very significant body of work and would involve the identification, assessment, determination and harmonisation of a large number of requirements and parameters which are not within the remit of the Network Codes. As such, it was decided that it would not be the optimum solution to combine the implementation of the Network Codes with the potential harmonisation of the existing Grid Codes.

Submission 2

One respondent commented that in the case of a CCGT, the 100% refers to the combined total maximum of the CCGT's capacity (GTs and STs), allowing for any specific configuration limitations. They noted that the harmonisation of the EirGrid and SONI Grid Codes is not planned as part this proposal document. The primary concern of this proposal document is to ensure that the requirements of the RfG is met

SO Comments

The respondent is correct in their assumption that in the case of a CCGT, the 100% refers to the combined total of the CCGT's capacity, allowing for any specific configuration limitation.

In relation to their comment in relation to the harmonisation of the EirGrid and SONI Grid Codes, it was never planned to utilise the Network Codes to harmonise the two existing Grid Codes.

The harmonisation of the two existing Grid Code would a very significant body of work and would involve the identification, assessment, determination and harmonisation of a large number of requirements and parameters which are not within the remit of the Network Codes. As such, it was decided that it would not be the optimum solution to combine the implementation of the Network Codes with the potential harmonisation of the existing Grid Codes.

Submission 3

One respondent requested further clarity regarding the active power response for WFPS ideally in the form of additional guidance with for example benchmark behaviour. They also requested further clarity on the expected speed of frequency response during an active power ramp from minimum generation and during low resource output.

SO Comments

The existing detailed requirements can be found in section WFPS 1.5.3.3 of the Grid Code. Following further consultation with ENTSO-E, the TSO has proposed the parameters for active power response in line with the current Grid Code requirements. The TSO will submit the necessary derogation request to the CRU with regard to these requirements in due course. Please see section 2.3 for more details.

Submission 4

One respondent queried how the requirements of 15.2d (iii) differ from 15.2(d) (i) and (ii).

SO Comments

The difference relates to the changes in the frequency. (iii) relates specifies a step change in frequency, resulting a time limited response from the PGM (operating reserve) and (i) & (ii) relates to the ongoing frequency changes within the normal frequency band.

Submission 5

One respondent requested further clarification on how the frequency response in the Network Codes aligns with the current Grid Codes requirements.

SO Comments

The relevant Grid Code clauses will be updated with the relevant terminology.

Submission 6

One respondent requested clarification in relation to how this requirement does not supersede the Grid Code requirement for WFPS frequency requirements.

SO Comments

The existing detailed requirements can be found in section WFPS 1.5.3.3 of the Grid Code. Following further consultation with ENTSO-E, the TSO has proposed the parameters for active power response in line with the current Grid Code requirements. The TSO will submit the necessary derogation request to the CRU with regard to these requirements in due course. Please see section 4.3 for more details.

Submission 7

One respondent requested that a comment be included in the proposal in relation to the ramp rate limitations – “limited by the units maximum allowed power ramp rate” Otherwise they request that the SOs align the parameters with a ramp rate of 0.5%Pn/s.

SO Comments

The existing definitions of the ramp up and ramp down rates are currently defined in the existing Grid Code and shown below, already includes the necessary reference to the maximum ramp rates.

a. Ramp up rate – the maximum rate of increase in a Generation Unit Output after the end of the start-up period.
b. Ramp down rate – the maximum rate of decrease in a generation unit output after the end of the start-up period.

Consultation Submissions: Admissible initial time delay for activation of active power frequency response for PPMs

Submission 1

One respondent commented that there will always be delays introduced by measurement equipment the controller cycle time and the operation of pitch motors, valves etc. They suggest that a more realistic proposal would be 1 second. They also suggest that ancillary services contracts to provide enhanced capability from technologies capable of very fast response (e.g. batteries) could be set up separately.

SO Comments

The proposed requirement aligns with existing Grid Code requirements i.e. no additional delays should be introduced other than those inherent in the design of the frequency response system. The design and procurement of DS3 System Service contracts are outside the scope of this proposal document.

Submission 2

One respondent commented that the RfG makes a differentiation between PGMs with and without inertia but does not mention if they are synchronized or not. As WTGs PPMs have inertia (just not synchronized) they should be covered by the first category with an admissible delay of 2s.

SO Comments

Our proposal is that the admissible delay should be 0s with no time delays other than those inherent in the design of the frequency response system including inertia.

Submission 3

One respondent commented that they agreed with the proposal taking into account the inclusion allows for any inherent delay to be considered and accepted if reasonable.

SO Comments

Noted.

Consultation Submissions: Maximum admissible choice of full activation time

Submission 1

One respondent requested clarity around whether this requirement applies at the entire plant in multi-shift CCGT configuration or at unit level.

SO Comments

This requirement applies to the entire plant in a multi-shift CCGT.

Submission 2

One respondent recommended that all requirements should be proposed on an equality principle and those parameters should be harmonized at synchronous area level between EirGrid/ESB networks and NIE/ NIE network.

SO Comments

The agreed principle for the selection of the RfG parameters was to minimize any changes or deviations from the existing Grid Code requirements. It was also decided that the harmonisation of the existing Grid Codes would involve the identification, assessment, determination of a very large number of parameters and other requirements which are not within the remit of the network codes, it was decided that the implementation of the Network Codes should not be used as an opportunity to harmonise the EirGrid and SONI Grid Codes.

<u>*Submission 3*</u>

One respondent commented that the full activation time t_2 proposal is three times lower than the proposed 15sec in Table 2 of the final ENTSO-E IGD on Frequency Modes. They note that the Northern Ireland consultation template propose 15 second. They also noted that the time t_2 (5 sec) to achieve the full output includes the time t_1 (2 sec) for the max delay. It makes the response time after the delay equals 3 sec and 5%, which is demanding. Refer to Figure 6 of RfG.

SO Comments

The proposed activation time of 5 seconds is as per the existing primary operating reserve requirements.

The agreed principle for the selection of the RfG parameters was to minimize any changes or deviations from the existing Grid Code requirements. It was also decided that the harmonisation of the existing Grid Codes would involve the identification, assessment, determination of a very large number of parameters and other requirements which are not within the remit of the network codes, it was decided that the implementation of the Network Codes should not be used as an opportunity to harmonise the EirGrid and SONI Grid Codes.

If a PGM experiences a time delay of 2 seconds (t1) within the time to full output activation (t2 of 5 seconds), the PGM will only have 3 seconds to reach their full output activation and while it may be difficult, it should still be achievable. The obligation is on the PGM to minimize the anytime delay, thus maximizing the time available to reach their full output.

<u>*Submission 4*</u>

One respondent requested clarification in relation to how this requirement does not supersede the Grid Code requirement for WFPS frequency requirements.

SO Comments

The existing detailed requirements can be found in section WFPS 1.5.3.3 of the Grid Code. Following further consultation with ENTSO-E, the TSO has proposed the parameters for active power response in line with the current Grid Code requirements. The TSO will submit the necessary derogation request to the CRU with regard to these requirements in due course. Please see section 4.3 for more details.

<u>*Submission 5*</u>

One respondent commented that the 5 second proposal is in line with existing MFS and is acceptable.

SO Comments

Noted

Consultation Submissions: Capability relating to the duration of provision of full active power frequency response

Submission 1

One respondent said that they do not agree with the proposal. They commented that the RfG requires the specification of a value in the range 15-30 minutes. However as the current Grid Code does not require all generators to provide TOR2 the proposal is a significant new requirement which should be justified if greater than the minimum permitted value.

SO Comments

20 minutes was selected in line with current requirements in the Grid Code .

The existing Grid Code has different reserve requirements for PGMs and PPMs. We are currently in discussion regarding the retention of the existing Grid Code requirements for future PPMs. Unfortunately, until those discussions are concluded, we are not in a position to provide the clarity that you seek. We are hoping to conclude those discussions prior to 18th of May, and will issue the necessary clarification, following their conclusion.

In the interim, the proposed value of 20 minutes in line with the existing Grid Code requirements for replacement reserves which is defined as:

“Replacement reserves is the additional MW output (and/or reduction in Demand) required compared to the pre-incident output (or Demand) which is fully available and sustainable over a period from 20 minutes to 4 hours following the Event.”

5.1.5 Additional Non-Mandatory Frequency Requirements

There are a number of additional areas with non-mandatory requirements detailed in the RfG. Table 18 identifies the areas. In both cases, we do not intend to invoke these non-mandatory requirements at this time.

Requirement	Requirement in RfG	Proposal	Article Number	Type Applicability
Shorter initial FSM response delay for PGMs without inertia	Not specified	Not Mandatory – can be agreed on a case by case basis with System Services Contracts	15.2.d(iv)	Type A, B, C and D PGMs and offshore PPMs
Synthetic inertia capability for PPM	Not Specified	Not Mandatory – can be agreed on a case by case basis with System Services Contracts	21(2)	C and D PPMs

Table 18 - Areas with non-mandatory requirements detailed in the RfG

5.2 Voltage Theme

The non-exhaustive and non-mandatory voltage / fault ride through parameters cover a number of different requirements. The following sub-themes are discussed in the next sections:

- Automatic disconnection
- Reactive Power capability
  - Type B PGM Requirements
  - At maximum capacity
  - Below maximum capacity
  - Supplementary requirements
  - Reactive power control modes
- Voltage Control System for Synchronous PGMs
- Fault Ride Through (FRT)
  - FRT capability for PGMs connected at voltages less than 110 kV
  - FRT capability for PGMS connected at voltages of 110 kV or more
  - Fast fault current injection for PPMs
  - Post fault active power recovery for PPMs
  - Priority to active or reactive current

5.2.1 Automatic Disconnection Due to Voltage Level

5.2.1.1 Article 15.3: Type C Automatic Disconnection Due to Voltage Level

Non-Exhaustive Parameter Selection

Applies to Type C PGMs

Requirement

With regard to voltage stability, type C power-generating modules shall be capable of automatic disconnection when voltage at the connection point reaches a minimum/maximum voltage level for a certain period of time. Table 19 specifies the voltage and duration settings.

Proposal

Parameter	Parameter in RfG	Proposal		Article Number	Type Applicability	Justification Code
		Voltage	Duration			
Minimum Voltage below which Module will automatic disconnect	Not specified	0.87 p.u.	3s	15.3	C (PPM)	1
	Not specified	0.8 p.u.	1.1s	15.3		1
	Not specified	0.87 p.u.	2.5s	15.3	C (SPGM)	1
	Not specified	0.8 p.u.	0.7s	15.3		1
Maximum Voltage above which Module will automatic disconnect	Not specified	1.12 p.u.	0.7s	15.3	C PGMs	1

Table 19: Parameters for Automatic Disconnection

Justification

The values are specified as stipulated in the Conditions Governing Connection to the Distribution System[10].

5.2.1.2 Article 16.2.c: Type D Automatic Disconnection Due to Voltage Level

Non-Exhaustive Parameter Selection

Applies to Type D PGMs

Requirement

With regard to voltage stability, *the relevant system operator in coordination with the relevant TSO shall have the right to specify voltages at the connection point at which a power-generating module is capable of automatic disconnection. The terms and settings for automatic disconnection shall be agreed between the relevant system operator and the power-generating facility owner*

Proposal: Automatic Disconnection Due to Voltage Level [Transmission Connected]

Table 20 specifies the voltage and duration settings.

Parameter	Parameter in RfG	Proposal	Article Number	Type Applicability	Justification Code
Minimum Voltage below which Module will automatic disconnect	Not specified	Not Allowed	16.2.c	D PGMs	3
Maximum Voltage above which Module will automatic disconnect	Not specified	Not Allowed	16.2.c	D PGMs	3

Table 20: Type D Parameters for Automatic Disconnection

Justification: Automatic Disconnection Due to Voltage Level [Transmission Connected]

The current Grid Code does not stipulate voltage thresholds which allow for automatic disconnection. The TSO invokes the right to prohibit automatic disconnection from the Transmission System.

Consultation Submissions: Minimum Voltage below / Maximum Voltage above which Module will automatic disconnect

Submission 1

One respondent requested clarification on whether "Not Allowed" is consistent with generator interface protection which disconnects generator below/above a certain voltage? They comment that generators must have the right to disconnect if voltages fall below/exceed planning limits and may cause equipment damage.

SO Comments

The generator is not allowed to automatic disconnect from the system within the normal operating voltage range and shall stay connected to the system in events of voltage deviations outside the normal operating voltage ranges, if protection settings allow for it. This proposal specifies the capability of the equipment and not the site specific settings of protection.

Submission 2

One respondent requested clarification with regards to the expectation of the requirements and the intended proposal. They propose that as low/high voltage protection settings have to be set that the values of protections settings should be below/above the minimum/maximum voltage where the generator shall continuously operate. They further state that if this is related to the protection between the substation and the MV system that the comment can be ignored.

Another respondent comments that for industrial systems RfG art 6.3 shall be considered.

SO Comments

The generator is not allowed to automatic disconnect from the system within the normal operating voltage range and shall stay connected to the system in events of voltage deviations outside the normal operating voltage ranges, if protection settings allow for it. This proposal specifies the capability of the equipment and not the site specific settings of protection.

The SO notes this comment that RfG art 6.3 gives generators the right to ask for industry specific requirements. This will be considered during the Grid and Distribution Code modification process.

Proposal: Automatic Disconnection Due to Voltage Level [Distribution Connected]

Table 21 specifies the voltage and duration settings.

Parameter	Parameter in RfG	Proposal		Article Number	Type Applicability	Justification Code
		Voltage	Duration			
Minimum Voltage below which Module will automatic disconnect	Not specified	0.87 p.u.	3s	15.3	D(PPM)	1
	Not specified	0.8 p.u.	1.1s	15.3		1
	Not specified	0.87 p.u.	2.5s	15.3	D (SPGM)	1
	Not specified	0.8 p.u.	0.7s	15.3		1
Maximum Voltage above which Module will automatic disconnect	Not specified	1.12 p.u.	0.7s	15.3	D PGMs	1

Table 21: Parameters for Automatic Disconnection

Justification: Automatic Disconnection Due to Voltage Level [Distribution Connected]

The values are specified as stipulated in the Conditions Governing Connection to the Distribution System[10].

Consultation Submissions

Submission 1

One respondent commented that Article 6.3 must be considered for industrial systems.

SO Comments

The SO notes this comment that RfG art 6.3 gives generators the right to ask for industry specific requirements

5.2.2 Reactive Power Capability

The following sections discuss the reactive power capability requirements under RfG. Section 5.2.2.1 discusses the requirements at maximum capacity whilst section 5.2.2.3 discusses the requirements below maximum capacity. The requirements for synchronous power generating modules (SPGM) and Power Park Modules (PPMs) are discussed separately under each of these two sections.

It should be noted that the capabilities are different for different connections. The requirements are split out in the following sections to indicate this. The relevant elements of a connection for this discussion are:

1. Connection at 110 kV or more,
2. Connection at less than 110 kV,
3. Different topology connections at less than 110 kV.

5.2.2.1 Reactive Power Capability for Type B PGMs

5.2.2.1.1 Article 17.2.a: Reactive Power capability for Type B SPGMs

Non-Mandatory Requirement being made Mandatory

Applies to Type B PGMs

Requirement

(a) with regard to reactive power capability, the relevant system operator shall have the right to specify the capability of a synchronous power generating module to provide reactive power;

Proposal

Requirement	Requirement in RfG	Proposal	Article Number	Type Applicability	Justification Code
right to specify the capability of a synchronous power generating module to provide reactive power;	To specify or not to specify	Invoke right to specify but for now maintain existing reactive power requirements in DCC 6.9 of the Distribution Code.	17.2.a	Type B SPGMs	1

Table 22: Right to specify reactive power capability for SPGMs

Justification

ESBN may at some point in the future wish to mandate the provision of reactive power from Type B PGMs. However, for now it is proposed to leave the existing reactive power requirements in DCC6.9 of the Distribution Code as is.

Consultation Submissions

Submission 1

DCC 10.10.2.1

Voltage Range	Connected at:	At 100% Registered Capacity	At 35% of Registered Capacity
99kV ≤ V ≥ 123kV	110kV	0.93 power factor leading to 0.85 power factor lagging	0.7 power factor leading to 0.4 power factor lagging
85kV ≤ V ≥ 99kV		Unity power factor to 0.85 power factor lagging	0.7 power factor leading to 0.4 power factory lagging

SO Comments

The requirements depicted in this table relate to 110 kV connected generators.

5.2.2.1.2 Article 20.2.a: Reactive Power capability for Type B PPMs

Non-Mandatory Requirement being made Mandatory

Applies to Type B PPMs

Requirement

(b) with regard to reactive power capability, the relevant system operator shall have the right to specify the capability of a power park modules to provide reactive power;

Proposal

Requirement	Requirement in RfG	Proposal	Article Number	Type Applicability	Justification Code
right to specify the capability of a Power Park Module to provide reactive power;	To specify or not to specify	Invoke the right to specify but for now, maintain existing reactive power requirements in DCC6.9 the Distribution Code.	20.2.a	Type B PPM	1

Table 23: Right to specify reactive power capability for PPMs

Justification

ESBN may at some point in the future wish to mandate the provision of reactive power from Type B PGMs. However, for now, it is proposed to leave the existing reactive power requirements in DCC6.9 of the Distribution Code as is.

Consultation Submissions

Submission 1

DCC 10.10.2.1

Voltage Range	Connected at:	At 100% Registered Capacity	At 35% of Registered Capacity
99kV ≤ V ≥ 123kV	110kV	0.93 power factor leading to 0.85 power factor lagging	0.7 power factor leading to 0.4 power factor lagging
85kV ≤ V ≥ 99kV		Unity power factor to 0.85 power factor lagging	0.7 power factor leading to 0.4 power factory lagging

SO Comments

The requirements depicted in this table relate to 110 kV connected generators.

5.2.2.2 Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles

5.2.2.2.1 Article 18.2.b. (i): SPGM: Parameters required for U-Q/Pmax Profiles

Non-Exhaustive Parameter Selection

Applies to Type C and D SPGMs

Requirement

In relation to voltage stability, synchronous power-generating modules shall fulfil the requirements with regard to reactive power capability at maximum capacity. For that purpose a U-Q/P_{max}-profile is specified (inner envelope) within the boundaries of the fixed outer envelope of which the synchronous power-generating module shall be capable of providing reactive power at its maximum capacity (P_{max}).

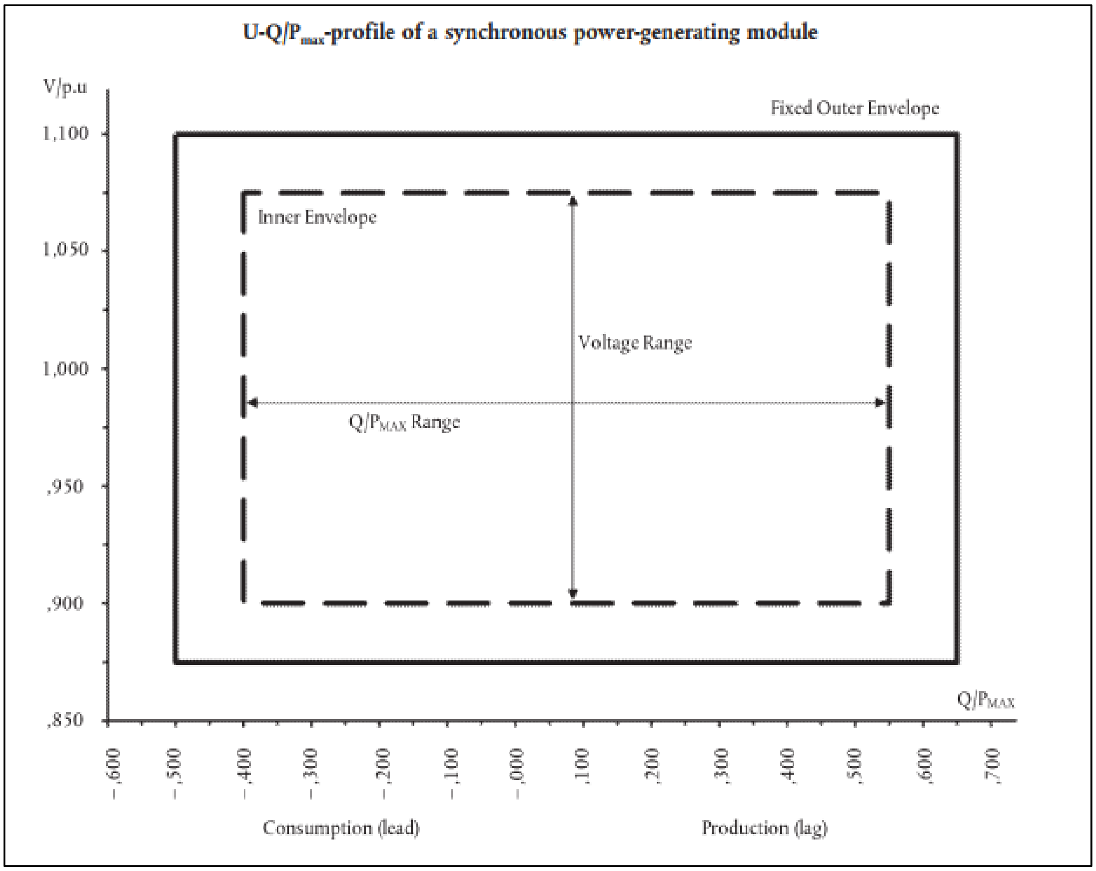

Figure 2: U-Q/Pmax-profile for synchronous Power-Generating Modules

The figure above represents boundaries of a U-Q/P_{max}-profile by the voltage at the connection point, expressed by the ratio of its actual value and the reference 1p.u. value, against the ratio of the reactive power (Q) and the maximum capacity (P_{max}). The position, size and shape of the envelope are indicative. The dimensions of the inner envelope are limited by a maximum range of Q/P_{max} of 1.08p.u. and maximum range of steady state voltage level of 0.218p.u.

Proposal for SPGMs connected at a voltage level ≥ 110 kV

Table 24 lists the parameters which describe the U-Q/P_{max}-profile for SPGMs connected at a voltage level ≥ 110 kV.

Connection Voltage	Parameter	Parameter in RfG (outer envelope)	Proposal (Inner Envelope)	Article Number	Type Applicability	Justification Code
110 kV	u_{min}	0.875 p.u.	0.9 p.u.	18.2.b (ii)	D SPGMs	1
	u_{max}	1.118 p.u.	1.118 p.u.			1
	Q_{min}/P_{max} (lead)	-0.5 p.u.	-0.5 p.u.			2
	Q_{max}/P_{max} (lag)	0.65 p.u.	0.52 p.u.			2
220 kV	u_{min}	0.875 p.u.	0.9 p.u.			2
	u_{max}	1.118 p.u.	1.118 p.u.			2
	Q_{min}/P_{max} (lead)	-0.5 p.u.	-0.5 p.u.			2
	Q_{max}/P_{max} (lag)	0.65 p.u.	0.52 p.u.			2
400 kV	u_{min}	0.875 p.u.	0.9 p.u.			1
	u_{max}	1.05 p.u.	1.05 p.u.			1
	Q_{min}/P_{max} (lead)	-0.5 p.u.	-0.5 p.u.			2
	Q_{max}/P_{max} (lag)	0.65 p.u.	0.52 p.u.			2

Table 24: Definition of U-Q/Pmax-profile at Maximum Capacity for SPGMs: connection @ ≥110 kV

Justification: SPGMs connected at a voltage level ≥ 110 kV

The RfG stipulates the reactive power capability as measured at the connection point. The Grid Code currently requests reactive power capability from SPGMs at the alternator terminals. Hence, the reactive power capability of synchronous power-generating modules is projected onto the new measuring point the connection point.

The proposed reactive power capability parameters (Q_{min}/P_{max} (lead) and Q_{max}/P_{max} (lag)) of inner envelope has to take into account the supplementary reactive power which is compensated by the equipment connecting the alternator terminal and connection point in order to maintain the currently required reactive power capability. The voltage (u_{min} and u_{max}) ranges are aligned with the RfG voltage ranges within which the PGM shall stay connected to the network and operate normally.

Post Consultation Note

ENTSO-E has confirmed that there is an error in the RfG Network Code in relation to u_{max}. The maximum of u_{max} should be based on the maximum withstand capability as set out in Article 16.2(a) (i). Therefore it should be noted that the voltage ranges of this proposal are all aligned with the RfG normal operating voltage ranges.

For the 110 kV voltage level, 1.118 p.u. aligns with the current ranges as per today's Grid Code requirements requirements. For the 220 kV voltage level these differ from current ranges as per today's Grid Code requirements. The 220 kV voltage ranges is as follows for 220 kV:

- 220 kV range today: 0.909pu < u < 1.114pu or 200 kV < U < 245 kV (CC.7.3.6.1)

Consultation Submissions

Submission 1

One respondent commented that the requirements were previously imposed at the generator terminals (0.95 under excited to 0.8 overexcited), now they are imposed at the HV terminals of the Generator Step-up Transformer. They requested clarification on whether the requirement for a generator power factor is removed after the implementation of RfG. Article 18.2.b (i) RfG implementation?

SO Comments

The measuring point for reactive power capability is either the generator terminal for existing generators or the HV terminal for RfG applicable generators.

RfG does apply to the following generators:

1. New i.e. those generators whose main plant & equipment is procured post May 2018
2. Where a significant modification has been carried out to an existing unit.

Submission 2

One respondent requested clarification on what assumptions were used for the technical characteristics of the Generator Step-up Transformer for example the sizing, impedance, number of taps and the Unit Auxiliary Transformer VAr loading for the example of a 10MW generating unit and above (upto750MVA) to reach the proposed projected at PCC inner parameter envelope. They suggested that they will carry out an engagement piece to ensure that the requirement is achievable with standard design practice.

SO Comments

The TSO carried out an assessment based on today's installed power transformers to quantify reactive power absorption of the transformers in order to project the reactive power requirements from generator's terminal to connection point. The assessment was carried out using step-up transformer as installed today. Hence, the requirement should be achievable with standard design practice.

Submission 3

One respondent commented that in their opinion. The under excited (leading) proposal of -0.5 (Qmin/Pmax) and 0.9p.u. voltage and overexcited (lagging) proposal of 0.52 (Qmax/Pmax) and 1.1p.u. voltage can have a huge impact in the generator size, min and max voltage at generator terminal and GSUT size (and price). They would also like to note that a generator may be unlikely to operate at a leading power factor when there is a low voltage at the connection point or similarly at a lagging power factor when there is a high voltage. They suggest that the shape of the inner envelope should take this into account and be translated to a more appropriate shape like a parallelogram.

SO Comments

The requirements and shape of the inner envelope are as per today's Grid Code requirements and are the projected values from the generator's terminal to the connection point. The proposed requirement is not expected to be more onerous than the current. The RSO reserves the right to require a reactive power capability of leading power factor with low voltage / lagging power factor with high voltage in order to resolve voltage violation in a vast area of the system. The reactive power capability is required at the connection point and could be provided by a combination of generator and supportive reactive compensation in order to fulfill the rectangular inner envelope shape.

Submission 4

One respondent commented that the voltage and Q/Pmax requirements at partial load are missing from the consultation paper.

SO Comments

Reactive power capability at partial load is mandatory and a site specific exhaustive parameter. Therefore it does not form a part of this proposal document. According to the RfG Article 18 2 (c) with regards to reactive power capability below maximum capacity, when operating at an active power output below maximum capacity, the synchronous power-generating modules shall be capable of generating at every possible operating point in the P-Q-capability diagram of the alternator of that synchronous power – generating module, at least down to minimum stable operating level.

Submission 5

One respondent requested that the Pmax maximum capacity for a CCGT multiple generator configuration is defined. They would like clarification about whether this is at unit or plant level and whether it is measured at the generator terminals or at the point of connection.

SO Comments

RfG requirements are applicable at the connection point, therefore at plant level.

Submission 6

One respondent commented that the proposed u_{min} (400 kV) value of 0.875p.u. does not align with the RfG voltage withstand capability ranges which state that u_{min} = 0.9.

SO Comments

The u_{min} (400 kV) = 0.875 p.u. is the system voltage during transom system disturbances or following transmission faults as per today's Grid Code requirements. But the voltage range applicable for reactive power capability should be aligned with normal operating voltage ranges. Hence, u_{min} (400 kV) is proposed to be amended to a u_{min} (400 kV) value of 0.9pu.

Submission 7

One respondent commented that a real test of compliance at 'extreme' grid voltages is not possible (0.9 p.u. or 1.1 voltages). They request clarification on how this will be tested or what proof of compliance is required to demonstrate compliance.

SO Comments

The Grid Code compliance testing will test as much as system conditions will allow on the day in question, beyond that the requirement will be policed by the Grid Code Testing team by exception.

Submission 8

One respondent suggested that the requirements in this document should be harmonized at synchronous area level between EirGrid and SONI.

SO Comments

The harmonisation of the two existing Grid Code would a very significant body of work and would involve the identification, assessment, determination and harmonisation of a large number of requirements and parameters which are not within the remit of the Network Codes. As such, it was decided that it would not be the optimum solution to combine the implementation of the Network Codes with the potential harmonisation of the existing Grid Codes.

Submission 9

One respondent commented that the RfG does not prevent the use of a non-rectangular shape for reactive power capability. They suggest that different shapes could be proposed to accommodate for operational points that are unlikely to happen such as over excitation at high voltage or under excitation at low voltages. They recommend that this is especially necessary for synchronous generators. They propose two examples for reference, firstly from the National Grid, Grid Code CC.6.3.4 and secondly VDE - VDE AR-4120, where different possible 'internal' shapes are provided to be chosen by the operator to adopt.

SO Comments

The requirements and shape of the inner envelope are as per today's Grid Code requirements requirements and are the projected values from the generator's terminal to the connection point. The RSO reserves the right to require a reactive power capability of leading power factor with low voltage/ lagging power factor with high voltage in order to resolve voltage violation in a vast area of the system. The reactive power capability is required at the connection point and could be provided by a combination of generator and supportive reactive compensation in order to fulfill the rectangular inner envelope shape.

Submission 10

One respondent comments that the inner envelope from -0.52 Qmax/Pmax to +0.5 Pmax/Qmax is very wide for synchronous generators. They suggest that the parameters of the inner envelope be reduced.

SO Comments

For transmission connected generators, the requirements and shape of the inner envelope are as per today's Grid Code requirements and are the projected values from the generator's terminal to the connection point.

The RSO reserves the right to require a reactive power capability of leading power factor with low voltage/ lagging power factor with high voltage in order to resolve voltage violation in a vast area of the system.

The reactive power capability is required at the connection point and could be provided by a combination of generator and supportive reactive compensation in order to fulfill the rectangular inner envelope shape.

Proposal for SPGMs connected at a voltage level < 110 kV

Table 25 below lists the parameters which describe the U-Q/P_{max}-profile for SPGMs connected at a voltage level < 110 kV.

Connection Voltage	Parameter	Parameter in RfG (outer envelope)	Proposal (Inner Envelope)	Article Number	Type Applicability	Justification Code
10 kV and 20 kV	u_{min}	0.875 p.u.	0.96 p.u.	18.2.b (ii)	C and D SPGMs	1
	u_{max}	1.118 p.u.	1.118 p.u.	18.2.b (ii)	C and D SPGMs	2
	Q_{min}/P_{max} (import)	-0.5 p.u.	-0.33 p.u.	18.2.b (ii)	C and D SPGMs	2
	Q_{max}/P_{max} (Export)	0.65 p.u.	0 p.u.	18.2.b (ii)	C and D SPGMs	2
38 kV	u_{min}	0.875 p.u.	0.937 p.u.	18.2.b (ii)	C and D SPGMs	1
	u_{max}	1.118 p.u.	1.118 p.u.	18.2.b (ii)	C and D SPGMs	1
	Q_{min}/P_{max} (Import)	-0.5 p.u.	-0.33 p.u.	18.2.b (ii)	C and D SPGMs	2
	Q_{max}/P_{max} (Export)	0.65 p.u.	0 p.u.	18.2.b (ii)	C and D SPGMs	2

Table 25: Definition of U-Q/Pmax-profile at Maximum Capacity for SPGMs: connection @ <110 kV

Justification: SPGMs connected at a voltage level <110 kV

Voltage

The current version of the Distribution Code does not explicitly graphically depict U-Q profiles. However, it does have table 6A (as per Distribution Code table numbering), which depicts a range of normal operating voltages.

TABLE 6A

Description	Nominal Voltage	Normal Operating Range [kV][5]	
		Lower bound	Upper bound
MV	10kV	9.6	11.3
MV	20kV	19.3	22.5
HV	38kV	35.6	43.8
110kV	110kV	99	123

In the current Distribution Code, for non-wind generators, no explicit linkage is made between the reactive power requirements and voltage ranges. RfG stipulates that such a requirement is specified.

It is proposed that for connections at voltages <110 kV, the power factor requirements stated for non-wind generators, will have to be maintained for the voltages in Table 6A (as per the Distribution Code table numbering) above.

Q limits:
It is proposed to align the Q limits for the U-Q profile with the P-Q profile. The synchronous power-generating module shall be capable of moving to any operating point within its U-Q/P_{max} profile in appropriate timescales to target.

Post Consultation Note

ENTSO-E has confirmed that there is an error in the RfG Network Code in relation to U_{max}. The maximum of Umax should be based on the maximum withstand capability as set out in Article 16.2(a) (i). Therefore it should be noted that the voltage ranges of this proposal are all aligned with the RfG normal operating voltage ranges.

For the 110 kV and 38 kV voltage levels the maximum allowable range of 1.118 p.u. as been selected in this proposal document. This is still below the current requirements in the Distribution Code and there is further investigation into these values ongoing.

Please note that there is an additional area for further consideration in relation to the historical misalignment that has developed between the nominal voltages and the voltages to which the distribution system is currently planned and operated to. Please see section 4.3 for further details on this.

Consultation Submissions

Submission 1

One respondent commented that the value of 0 p.u. Qmax/Pmax (export) seems to be wrong. They mention that the Northern Ireland proposed value is 0.33 p.u.

SO Comments

This is correct for Ireland, only PPMs >5MW and what will be referred to as Topology 2 post RfG adoption are permitted to export reactive power.

5.2.2.2.2 Article 18.2.b. (iv): SPGM: Time to Achieve Target Value within U-Q/Pmax Profile

Non-Exhaustive Parameter Selection

Applies to Type C and D SPGMs

Requirement

(iv) *the synchronous power-generating module shall be capable of moving to any operating point within its U-Q/Pmax profile in appropriate timescales to target values requested by the relevant system operator*;

Proposal

Parameter	Parameter in RfG	Proposal	Article Number	Type Applicability	Justification Code
Time to achieve target value [transmission connected]	Not specified	Without undue delay but at least within 120 seconds	18.2.b (iv)	C and D SPGMs	1
Time to achieve target value [distribution connected]	Not specified	Without undue delay but at least within 120 seconds	18.2.b (iv)	C and D SPGMs	3

Table 26: Timescales to Achieve Target Values at Maximum Capacity

Justification: Transmission Connected

The time to achieve the target value is as per the current requirement set out in the Scheduling and Dispatch Code Appendix B (SDC2.B.8) of the Grid Code for centrally dispatched generating units. These units are being dispatched via the TSO electronic interface program (EDIL); however the same time period will apply for units being dispatched via set point control.

Justification: Distribution Connected

The time to achieve the target value is a new parameter in the Distribution Code.

For a small sub-set of distribution connected generators, it may be agreed on a case by case basis, that reactive power will be dispatched by the TSO via EDIL. Where this arises, the value chosen is to align with the current value [MW] for centrally dispatched generating units in the Grid Code. For the avoidance of doubt, centrally dispatched SPGMs will not have their reactive power dispatched by EirGrid unless individually agreed as above.

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Consultation Submissions: Transmission Connected

Submission 1

One respondent suggests that the proposed value of 120 second time scale should be increased. They comment that to move from full lagging to full leading requires the use of a tap changer on larger units. Moving from one extreme of operation to the other will require longer than 120 seconds as several tap changes will be required. They ask if typical tap-changer operation time per tap have been assumed.

SO Comments

A Dispatch Instruction relating to Reactive Power will be implemented without delay and, notwithstanding the provisions of SDC2.4.2.12 and subject as provided in this SDC2 - Appendix B (Dispatch Instructions for Generator Reactive Power) will be achieved not later than 2 minutes after the Dispatch Instruction time, or such longer period as the TSO may instruct.

Where the Dispatch Instructions require more than two taps per CDGU and that means that the Dispatch Instructions cannot be achieved within 2 minutes of the time of the Dispatch Instructions (or such longer period at the TSO may have Instructed), the Dispatch Instructions shall each be achieved with the minimum of delay after the expiry of that period;

Consultation Submissions: Distribution Connected

Submission 1

One respondent suggests that the proposed value of 120 second time scale should be increased. They comment that to move from full lagging to full leading requires the use of a tap changer on larger units. Moving from one extreme of operation to the other will require longer than 120 seconds as several tap changes will be required. They ask if typical tap-changer operation time per tap have been assumed.

SO Comments

For a small sub-set of distribution connected generators, it may be agreed on a case by case basis, that reactive power will be dispatched by the TSO via EDIL. Where this arises, a Dispatch Instruction relating to Reactive Power will be implemented without delay and, notwithstanding the provisions of SDC2.4.2.12 and subject as provided in this SDC2 - Appendix B (Dispatch Instructions for Generator Reactive Power) will be achieved not later than 2 minutes after the Dispatch Instruction time, or such longer period as the TSO may instruct.

Where the Dispatch Instructions require more than two taps per CDGU and that means that the Dispatch Instructions cannot be achieved within 2 minutes of the time of the Dispatch Instructions (or such longer period at the TSO may have Instructed), the

Dispatch Instructions shall each be achieved with the minimum of delay after the expiry of that period;

For other distribution connected SPGMs. There is no intent at this time for ESBN to dispatch reactive power.

5.2.2.2.3 Article 21.3.b (i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles

Non-Exhaustive Parameter Selection

Applies to Type C and D PPMs and Offshore PPMs

Requirement

Power Park modules shall fulfil requirements in relation to voltage stability with regard to reactive power capability at maximum capacity. For that purpose a U-Q/P_{max}-profile (inner envelope) is specified within the boundaries of the fixed outer envelope of which the Power Park Module shall be capable of providing reactive power at its maximum capacity (P_{max}).

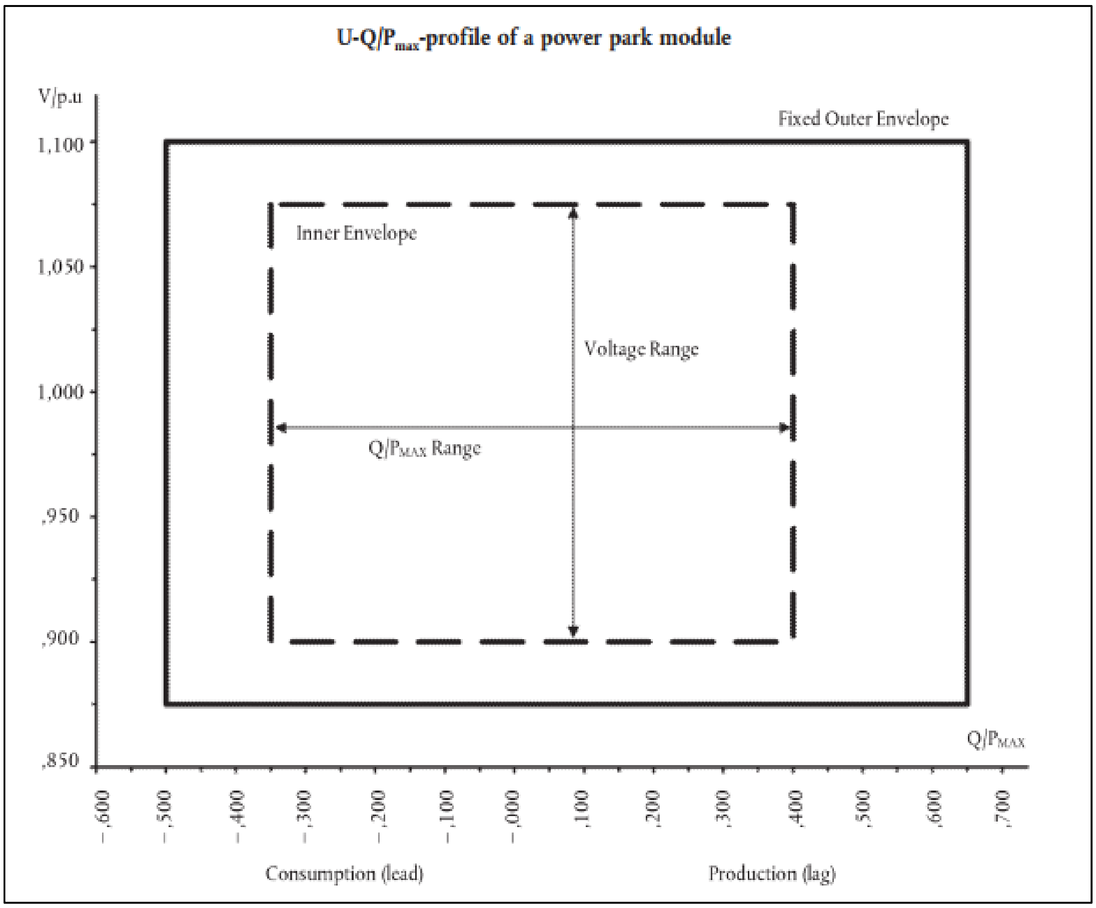


Figure 3: U-Q/Pmax-profile for Power Park Modules

The figure above represents boundaries of a U-Q/P_{max}-profile by the voltage at the connection point, expressed by the ratio of its actual value and the reference 1 p.u. value, against the ratio of the reactive power (Q) and the maximum capacity (P_{max}). The position, size and shape of the inner envelope are indicative.

The dimensions of the inner envelope are limited by a maximum range of Q/P_{max} of 0.66 and maximum range of steady state voltage level of 0.218 p.u.

Proposal for PPMs connection at a voltage level ≥ 110 kV

Table 27 lists the parameters which describe the U-Q/P_{max}-profile for PPMs connected at a voltage level ≥ 110 kV.

Connection Voltage	Parameter	Parameter in RfG (outer envelope)	Proposal (Inner Envelope)	Article Number	Type Applicability	Justification Code
110 kV	u_{min}	0.875 p.u.	0.9 p.u.	21.3.b (ii)	D PPMs and Offshore PPMs	1
	u_{max}	1.118 p.u.	1.118 p.u.	21.3.b (ii)	D PPMs and Offshore PPMs	1
	Q_{min}/P_{max} (lead)	-0.5 p.u.	-0.33 p.u.	21.3.b (ii)	D PPMs and Offshore PPMs	1
	Q_{max}/P_{max} (lag)	0.65 p.u.	0.33 p.u.	21.3.b (ii)	D PPMs and Offshore PPMs	1
220 kV	u_{min}	0.875 p.u.	0.9 p.u.	21.3.b (ii)	D PPMs and Offshore PPMs	2
	u_{max}	1.118 p.u.	1.118 p.u.	21.3.b (ii)	D PPMs and Offshore PPMs	2
	Q_{min}/P_{max} (lead)	-0.5 p.u.	-0.33 p.u.	21.3.b (ii)	D PPMs and Offshore PPMs	1
	Q_{max}/P_{max} (lead)	0.65 p.u.	0.33 p.u.	21.3.b (ii)	D PPMs and Offshore PPMs	1
400 kV	u_{min}	0.875 p.u.	0.9 p.u.	21.3.b (ii)	D PPMs and Offshore PPMs	1
	u_{max}	1.118 p.u.	1.05 p.u.	21.3.b (ii)	D PPMs and Offshore PPMs	1
	Q_{min}/P_{max} (lead)	-0.5 p.u.	-0.33 p.u.	21.3.b (ii)	D PPMs and Offshore PPMs	1
	Q_{max}/P_{max} (lag)	0.65 p.u.	0.33 p.u.	21.3.b (ii)	D PPMs and Offshore PPMs	1

Table 27: Definition of a U-Q/Pmax-profile at Maximum Capacity PPMs: connected @ 110 kV or more

Justification: PPMs connected at a voltage level ≥110 kV:

The reactive power parameters are as per the current Grid Code requirements.

The voltage ranges for the reactive power capability are aligned with the voltages specified for the synchronous power-generating modules in Table 24 in section 5.2.2.2.1.

Post Consultation Note

ENTSO-E has confirmed that there is an error in the RfG Network Code in relation to u_{max}. The maximum of u_{max} should be based on the maximum withstand capability as set out in Article 16.2(a) (i). Therefore it should be noted that the voltage ranges of this proposal are all aligned with the RfG normal operating voltage ranges given in this Article.

For the 110 kV voltage level, 1.118 p.u. aligns with the current ranges as per today's Grid Code requirements requirements. For the 220 kV voltage level these differ from current ranges as per today's Grid Code requirements. The 220 kV voltage ranges is as follows for 220 kV

- 220 kV range today: 0.909pu < u < 1.114pu or 200 kV < U < 245 kV (CC.7.3.6.1)

Consultation Submissions

Submission 1

One respondent requests more clarity on the proposal as they are not clear on the shape that the TSO has specified within the specified U and Q/Pmax coordinates. They assume a rectangle corresponding to these coordinates.

Please note, this comment was received across all voltage levels >110 kV and for both modes of operation. We have captured this comment and the SO response once for simplicity.

SO Comments

Parameters proposed in the proposal document determine the four corners of the rectangular inner envelope (see Figure 3).

This is applicable for all generators connected @ voltage level ≥110 kV

Proposal for PPMs connected at a voltage level < 110 kV

Table 28 lists the parameters which describe the U-Q/Pmax-profile lists the parameters which describe the revised U-Q/P_{max}-profile for PPMs connected a voltage level < 110 kV and in Topology 2[13].

Connection Voltage	Parameter	Parameter in RfG (outer envelope)	Proposal (Inner Envelope)	Article Number	Type Applicability	Justification Code
10 kV and 20 kV	u_{min}	0.875 p.u.	0.96 p.u.	21.3.b (ii)	C and D PPM and offshore PPMs	1
	u_{max}	1.118 p.u.	1.118 p.u.	21.3.b (ii)	C and D PPM and offshore PPMs	2
	Q_{min}/P_{max} (lead)	-0.5 p.u.	-0.33 p.u.	21.3.b (ii)	C and D PPM and offshore PPMs	2
	Q_{max}/P_{max} (lag)	0.65 p.u.	0.33 p.u.	21.3.b (ii)	C and D PPM and offshore PPMs	2
38 kV	u_{min}	0.875 p.u.	0.937 p.u.	21.3.b (ii)	C and D PPM and offshore PPMs	1
	u_{max}	1.118 p.u.	1.118 p.u.	21.3.b (ii)	C and D PPM and offshore PPMs	1
	Q_{min}/P_{max} (lead)	-0.5 p.u.	-0.33 p.u.	21.3.b (ii)	C and D PPM and offshore PPMs	2
	Q_{max}/P_{max} (lag)	0.65 p.u.	0.33 p.u.	21.3.b (ii)	C and D PPM and offshore PPMs	2

Table 28: Definition of a U-Q/Pmax-profile at Maximum Capacity PPMs connected @ <110 kV and in Topology 2

[13] See section 3.3 for a detailed description of the topologies.

Table 29 lists the parameters which describe the U-Q/Pmax-profile lists the parameters which describe the revised U-Q/P_{max}-profile for PPMs connected a voltage level < 110 kV and in all other Topologies.

Connection Voltage	Parameter	Parameter in RfG (outer envelope)	Proposal (Inner Envelope)	Article Number	Type Applicability	Justification Code
10 kV & 20 kV	u_{min}	0.875 p.u.	0.96 p.u.	21.3.b (ii)	C and D PPM	1
	u_{max}	1.118 p.u.	1.118 p.u.	21.3.b (ii)	C and D PPM	2
	Q_{min}/P_{max} (lead)	-0.5 p.u.	-0.42 p.u.	21.3.b (ii)	C and D PPM	2
	Q_{max}/P_{max} (lag)	0.65 p.u.	0 p.u.	21.3.b (ii)	C and D PPM	2
38 kV	u_{min}	0.875 p.u.	0.937 p.u.	21.3.b (ii)	C and D PPM	1
	u_{max}	1.118 p.u.	1.118 p.u.	21.3.b (ii)	C and D PPM	1
	Q_{min}/P_{max} (lead)	-0.5 p.u.	-0.42 p.u.	21.3.b (ii)	C and D PPM	2
	Q_{max}/P_{max} (lag)	0.65 p.u.	0 p.u.	21.3.b (ii)	C and D PPM	2

Table 29: Definition of a U-Q/Pmax-profile at Maximum Capacity for PPMs connected @ <110 kV & all other Topologies

Justification: PPMs connected at a voltage level <110 kV

Voltage

The current version of the Distribution Code does not explicitly graphically depict U-Q profiles. However, it does have Table 6A, which depicts a range of normal operating voltages.

TABLE 6A

Description	Nominal Voltage	Normal Operating Range [kV][5]	
		Lower bound	Upper bound
MV	10kV	9.6	11.3
MV	20kV	19.3	22.5
HV	38kV	35.6	43.8
110kV	110kV	99	123

Linkage between Reactive Power requirements and voltage ranges:

DCC 11.4.3, which covers existing Types [Topologies][14] B [<5 MW], C, D and E, does not contain any explicit reference to having the P-Q capability across specific voltage ranges.

[14] See section 3.3 for a detailed description of the topologies."

DCC 11.4.5, which covers existing Types [Topologies] A and B [>5 MW], does explicitly state that the P-Q capability must be maintained across the voltage ranges is Table 6A.

It is proposed that for connections at voltages <110 kV, the power factor requirements stated for non-wind generators, will have to be maintained for the voltages in Table 6A.

Figure 4 below depicts the DCC 11.4.5 requirement graphically.

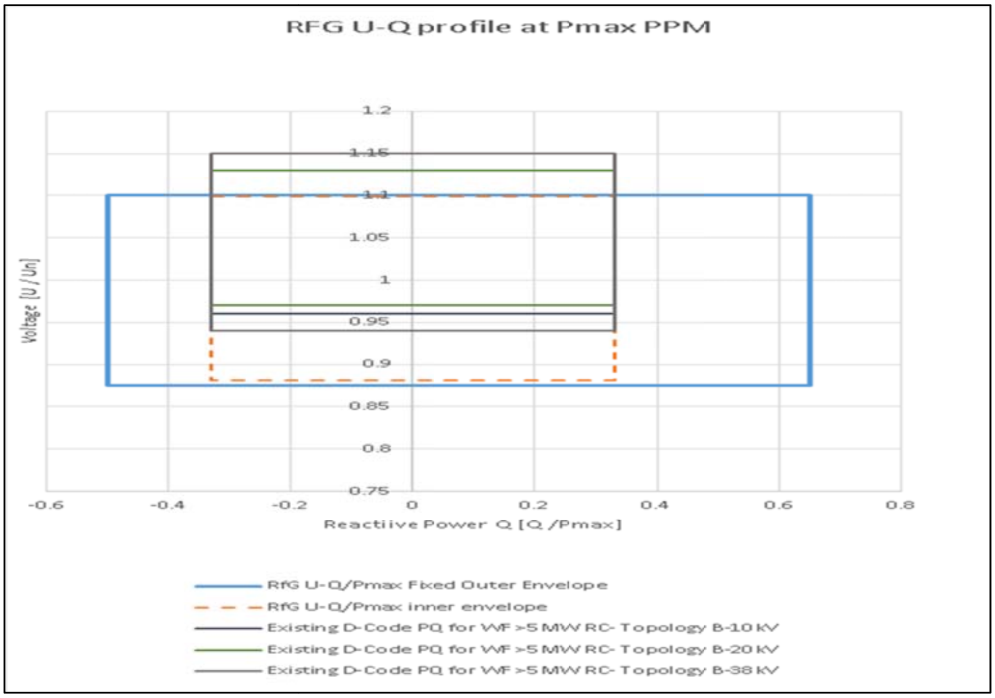


Figure 4: PPM U-Q Profile @ Pmax connected at a voltage level <110 kV

Clearly these are currently outside the allowable limits specified in RfG. See Section 3.3 above for the proposed methodology for resolving this issue.

Q limits:
RfG states that for the U-Q profile, Q limits maximum must also be stipulated. This range must not exceed 0.66 Q/Pmax in total. Hence the existing and new requirements are aligned.

Post Consultation Note

ENTSO-E has confirmed that there is an error in the RfG Network Code in relation to u_{max}. The maximum of u_{max} should be based on the maximum withstand capability as set out in Article 16.2(a) (i). Therefore it should be noted that the voltage ranges of this proposal are all aligned with the RfG normal operating voltage ranges.

Please note that there is an additional area for further consideration in relation to the historical misalignment that has developed between the nominal voltages and the voltages to which the distribution system is currently planned and operated to. Please see section 4.3 for further details on this.

Consultation Submissions

Submission 1

One respondent requests more clarity on the proposal as they are not clear on the shape that the TSO has specified within the specified U and Q/Pmax coordinates. They assume a rectangle corresponding to these coordinates.

Please note, this comment was received across all voltage levels <110 kV, for both modes of operation and for all topologies. We have captured this comment and the SO response once for simplicity.

SO Comments

For DSO connected generators please see shapes in the justification section above.

5.2.2.3 Reactive Power Capability below Maximum Capacity: P-Q/Pmax Profiles

5.2.2.3.1 Article 21.3.c (i), (ii) and (iv): PPM: Parameters required for P-Q/Pmax Profiles

Non-Exhaustive Parameter Selection

Applies to Type C and D PPMs

Requirement

Power park modules shall fulfil the following additional requirements in relation to voltage stability with regard to reactive power capability below maximum capacity. For that purpose a P- Q/P_{max}-profile is specified within the boundaries of which the power park module shall be capable of providing reactive power below maximum capacity ($P < P_{max}$).

The figure below represents boundaries of a P- Q/P_{max}-profile by the voltage at the connection point, expressed by the ratio of its actual value and the reference 1 p.u. value, against the ratio of the reactive power (Q) and the maximum capacity (P_{max}). The position, size and shape of the inner envelope are indicative.

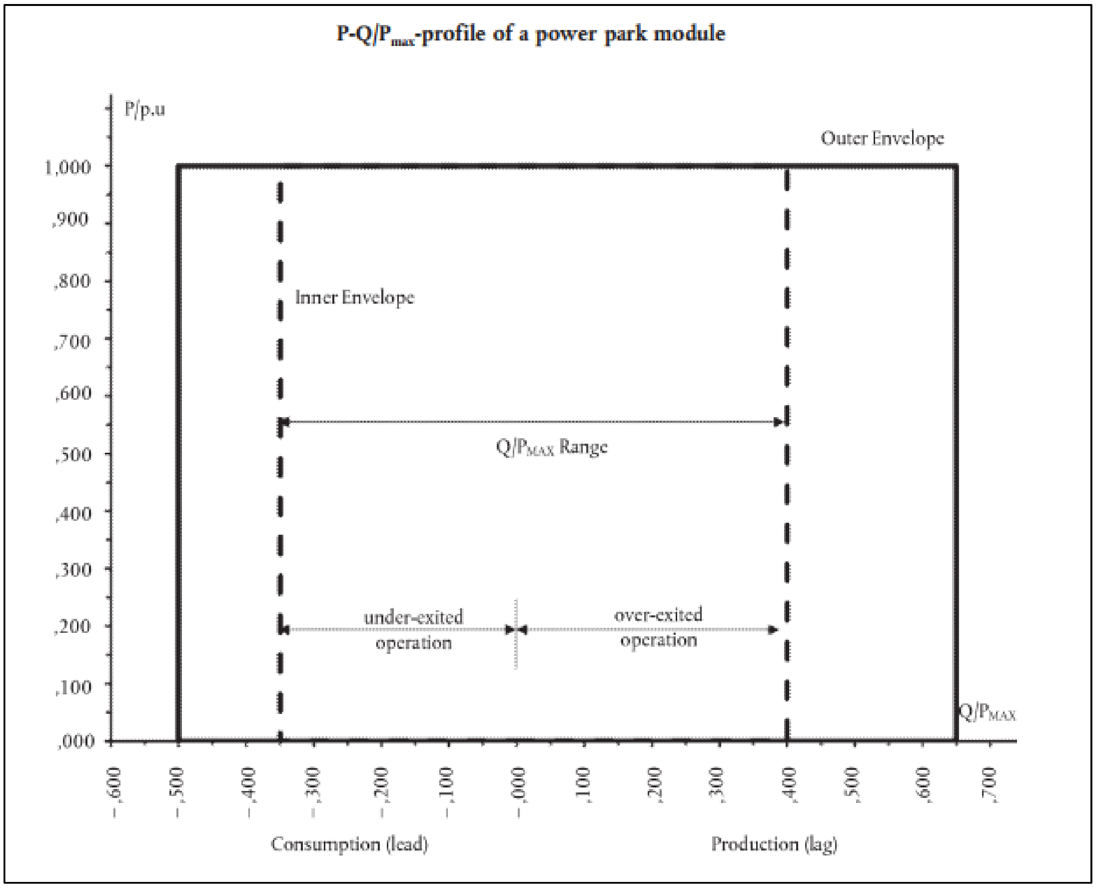


Figure 5: P- Q/Pmax-profile of a PPM

The diagram represents boundaries of a P-Q/P_{max}-profile at the connection point by the fixed outer envelope.

Proposal PPMs connected at a voltage level ≥ 110 kV

Table 30 lists the parameters which describe the P-Q/P_{max}-profile for PPMs connected at a voltage level ≥110 kV.

Connection Voltage	Parameter	Parameter in RfG	Proposal	Article Number	Type Applicability	Justification Code
110 to 400 kV	p_{min}	0.0 p.u.	0.12 p.u.	21.3.c (ii)	D PPMs	1
	p_{max}	1.0 p.u.	1.0 p.u.	21.3.c (ii)	D PPMs	1
	Q_{min}/P_{max} (lead)	-0.5 p.u.	-0.33 p.u.	21.3.c (ii)	D PPMs	1
	Q_{max}/P_{max} (lag)	0.65 p.u.	0.33 p.u.	21.3.c (ii)	D PPMs	1

Table 30: Timescales to Achieve Target Values at Maximum Capacity

Justification: PPMs connected at a voltage level ≥ 110 kV

The reactive power capability requirements are as per the current Grid Code requirements stipulated in WFPS.1.6.3.1.

Consultation Submissions

Submission 1

One respondent requests more clarity on the proposal as they are not clear on the shape that the TSO has specified within the specified U and Q/Pmax coordinates. They assume a rectangle corresponding to these coordinates.

Please note, this comment was received across all voltage levels <110 kV and for both modes of operation. We have captured this comment and the SO response once for simplicity.

SO Comments

Parameters proposed in the proposal document determine the four corners of the rectangular inner envelope (see Figure 5).

This is applicable for all generators connected @ voltage level ≥110 kV.

Reactive power capability for generators connected to the distribution system could vary (see Figure 6).

Proposal PPMs connected at a voltage level < 110 kV

The reactive power requirements for wind generators in the existing Distribution Code are consistent with the P-Q inner and outer envelopes stipulated by RfG and **hence no change is required**. This is depicted diagrammatically in Figure 6 below. For consistency, these diagrams are shown in a tabular format in the following pages.

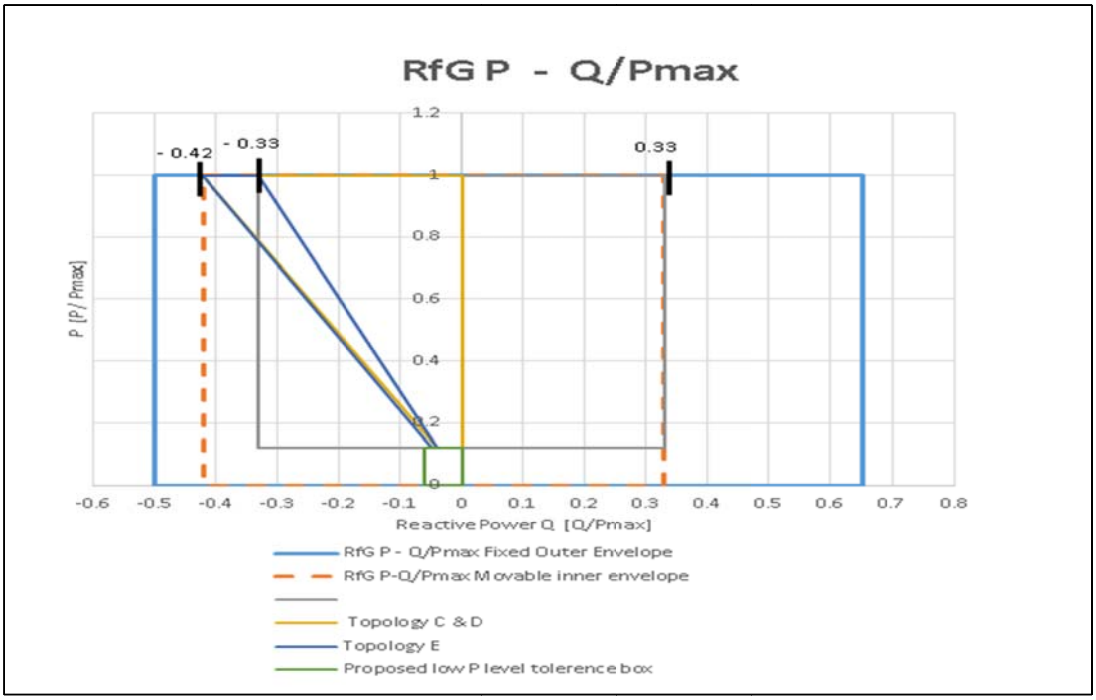


Figure 6: Reactive power capability of PPM connected to distribution system

Table 31 lists the parameters which describe the P-Q/P_{max}-profile for PPMs connected at a voltage level <110 kV and in Topology 2.

Connection Voltage	Parameter	Parameter in RfG	Proposal	Article Number	Type Applicability	Justification Code
Connection voltages at 10 kV, 20 kV or 38 kV.	p_{min}	0.0 p.u.	0.12 p.u.	21.3.c (ii)	C and D PPM	1
	p_{max}	1.0 p.u.	1.0 p.u.	21.3.c (ii)	C and D PPM	1
	Q_{min}/P_{max} (lead)	-0.5 p.u.	-0.33 p.u.	21.3.c (ii)	C and D PPM	1
	Q_{max}/P_{max} (lag)	0.65 p.u.	0.33 p.u.	21.3.c (ii)	C and D PPM	1

Table 31: P-Q/Pmax-profile below Maximum Capacity PPMs: connection @ <110 kV & in Topology 2

Table 32 lists the parameters which describe the P-Q/P_{max}-profile for PPMs connected at a voltage level <110 kV and in Topologies 3 and 4.

Connection Voltage	Parameter	Parameter in RfG	Proposal	Article Number	Type Applicability	Justification Code
Connection voltages at 10 kV, 20 kV or 38 kV.	**p_{min}**	0.0 p.u.	0.12 p.u.	21.3.c (ii)	C and D PPM	1
	p_{max}	1.0 p.u.	1.0 p.u.	21.3.c (ii)	C and D PPM	1
	Q_{min}/P_{max} (lead)	-0.5 p.u.	Power factor range from 0.92 [-0.42 Q / Pmax] to unity [0 Q/Pmax]	21.3.c (ii)	C and D PPM	1
	Q_{max}/P_{max} (lag)	0.65 p.u.	Power factor range from 0.92 [-0.42 Q / Pmax] to unity [0 Q/Pmax]	21.3.c (ii)	C and D PPM	1

Table 32: P-Q/Pmax-profile below Maximum Capacity PPMs connection@<110 kV & Topologies 3 & 4

Table 33 lists the parameters which describe the P-Q/P_{max}-profile for PPMs connected at a voltage level <110 kV and in Topology 5.

Connection Voltage	Parameter	Parameter in RfG	Proposal	Article Number	Type Applicability	Justification Code
Connection voltages at 10 kV, 20 kV or 38 kV.	**p_{min}**	0.0 p.u.	0.12 p.u.	21.3.c (ii)	C and D PPM	1
	p_{max}	1.0 p.u.	1.0 p.u.	21.3.c (ii)	C and D PPM	1
	Q_{min}/P_{max} (lead)	-0.5 p.u.	Power factor range from 0.92 [-0.42 Q / Pmax] to 0.95 [-0.33 Q/Pmax]	21.3.c (ii)	C and D PPM	1
	Q_{max}/P_{max} (lag)	0.65 p.u.	Power factor range from 0.92 [-0.42 Q / Pmax] to 0.95 [-0.33 Q/Pmax]	21.3.c (ii)	C and D PPM	1

Table 33: P-Q/Pmax-profile below Maximum Capacity for PPMs: connection @ <110 kV & Topology 5

Justification: PPMs connected at a voltage level <110 kV

Proposal is as per current Distribution Code requirements.

Consultation Submissions

Submission 1

One respondent requests more clarity on the proposal as they are not clear on the shape that the DSO has specified within the specified U and Q/Pmax coordinates. They assume a rectangle corresponding to these coordinates.

Please note, this comment was received across all voltage levels <110 kV, for both modes of operation and for all topologies. We have captured this comment and the SO response once for simplicity.

SO Comments

For DSO connected generators please see shapes in the justification section above.

5.2.2.3.2 Article 21.3.c. (iv): PPM: Time to Achieve Target Value within P-Q/Pmax Profile

Non-Exhaustive Parameter Selection

Applies to Type C and D PPMs

Requirement

(v) The power park module shall be capable of moving to any operating point within its P- Q/P_{max}-profile in appropriate timescales to target values requested by the relevant system operator.

Proposal

Parameter	Parameter in RfG	Proposal	Article Number	Type Applicability	Justification Code
Time to achieve target value [transmission connected]	Not specified	Without delay but within 20 seconds	21.3.c.(iv)	C and D PPMs	1
Time to achieve target value [distribution connected]	Not specified	Without delay but within 20 seconds	21.3.c.(iv)	C and D PPMs	1

Table 34: Timescales to Achieve Target Values at Maximum Capacity

Justification

This aligns with the current Grid Code requirements in WFPS.1.6.2 which stipulates that a change in set-point shall be implemented within 20 seconds of receipt of the appreciate signal from the TSO.

5.2.2.4 Supplementary Reactive Power Requirements

5.2.2.4.1 Article 18.2.a: SPGM: Supplementary reactive power requirements

Non-Mandatory Requirement being made Mandatory

Applies to Type C and D SPGMs

Requirement

The *relevant system operator may specify supplementary reactive power to be provided if the connection point of a synchronous power-generating module is neither located at the high-voltage terminals of the step-up transformer to the voltage level of the connection point nor at the alternator terminals, if no step-up transformer exists. This supplementary reactive power shall compensate the reactive power demand of the high-voltage line or cable between the high-voltage terminals of the step-up transformer of the synchronous power-generating module or its alternator terminals, if no step-up transformer exists, and the connection point and shall be provided by the responsible owner of that line or cable*.

Proposal

Requirement	Requirement in RfG	Proposal	Article Number	Type Applicability	Justification Code
Right to specify supplementary reactive power requirements when the connection point is remote	To specify or not to specify	RSOs reserve the right to specify	18.2.a	Type C and D SPGMs	1

Table 35: Right to Specify Supplementary Reactive Power Requirements for SPGMs

Justification

The TSO and DSO invoke the right to specify supplementary reactive power requirements for remote connection points in order to align with the supplementary reactive power requirements. This is not a new requirement. Currently the TSO and DSO have the right to specify supplementary reactive power requirements during the connection offer process and this will continue.

Consultation Submissions

Submission 1

One respondent requests more clarity on this proposal. They comment that care should be taken not to specify reactive power capability that gives rise to voltage rise issues. They give an example of a remote connection point that would benefit from more importing reactive power capability and not more exporting reactive power capability.

SO Comments

Any supplementary reactive power compensation required to offset the reactive power demand of the line or cable between the connection point and generator site will be identified during the connection offer process as per WFPS 1.6.3.2 of the Grid Code. The DSO does not currently have any such instances.

5.2.2.4.2 Article 21.3.a: PPM: Supplementary reactive power requirements

Non-Mandatory Requirement being made Mandatory

Applies to Type C and D PPMs

Requirement

The relevant system operator may specify supplementary reactive power to be provided if the connection point of a power park module is neither located at the high-voltage terminals of the step-up transformer to the voltage level of the connection point nor at the convertor terminals, if no step-up transformer exists. This supplementary reactive power shall compensate the reactive power demand of the high- voltage line or cable between the high-voltage terminals of the step-up transformer of the power park module or its convertor terminals, if no step-up transformer exists, and the connection point and shall be provided by the responsible owner of that line or cable.

Proposal

Requirement	Requirement in RfG	Proposal	Article Number	Type Applicability	Justification Code
Right to specify supplementary reactive power requirements when the connection point is remote	To specify or not to specify	RSOs reserve the right to specify	21.3.a	Type C and D PPMs	1

Table 36: Right to Specify Supplementary Reactive Power Requirements for PPMs

Justification

The TSO and DSO invoke the right to specify supplementary reactive power requirements for remote connection points in order to align with the supplementary reactive power requirements. This is not a new requirement. Currently the TSO and DSO have the right to specify supplementary reactive power requirements during the connection offer process and this will continue.

Consultation Submissions

Submission 1

One respondent requests more clarity on this proposal. They comment that care should be taken not to specify reactive power capability that gives rise to voltage rise issues. They give an example of a remote connection point that would benefit from more importing reactive power capability and not more exporting reactive power capability.

SO Comments

Any supplementary reactive power compensation required to offset the reactive power demand of the line or cable between the connection point and generator site will be identified during the connection offer process as per WFPS 1.6.3.2 of the Grid Code.

The DSO does not currently have any such instances.

5.2.2.5 Reactive Power Control Modes for PPMs

5.2.2.5.1 Article 21.3.d (iv) - Voltage Control Mode

Non-Exhaustive Parameter Selection

Applies to Type C and D PPMs

Requirement

Following a step change in voltage, the power park module shall be capable of achieving 90% of the change in reactive power output within a time t_1 and must settle at the value specified by the slope within a time t_2 with a steady-state reactive tolerance no greater than 5% of the maximum reactive power.

Proposal

The proposed times are listed in Table 37.

Parameter	Parameter in RfG	Proposal	Article Number	Type Applicability	Justification Code
t_1 = time within which 90% of the change in reactive power is reached	1 – 5 sec	1	21.3.d.(iv)	C and D PPMs	1
t_2 = time within which 100% of the change in reactive power is reached	5 – 60 sec	5	21.3.d.(iv)	C and D PPMs	3

Table 37: Parameters for Voltage Control Mode

Justification

The time t_1 within which 90% of the change in reactive power is reached is set to 1 second as per the current requirements in WFPS1.6.2.4 of the Grid Code

The time t_2 to achieve 100% of the change in reactive power is set to 5 seconds. This is a new requirement that is not currently set in the Grid Code.

5.2.2.5.2 Article 21.3.d (vi) - Power Factor Control Mode

Non-Exhaustive Parameter Selection

Applies to Type C and D PPMs

Requirement

For the purpose of power factor control mode, the power park module shall be capable of controlling the power factor at the connection point within the required reactive power range with a target power factor in steps no greater than 0,01.

Proposal

The target power factor value, its tolerance and the period of time to achieve the target power factor following a sudden change of active power output are specified in Table 38.

Parameter	Parameter in RfG	Proposal	Article Number	Type Applicability	Justification Code
Target power factor	Not specified	site-specific	21.3.d.(vi)	C and D PPMs	3
Time period to reach the set point	Not specified	90% within 1 second	21.3.d.(vi)	C and D PPMs	3
Tolerance	Not specified	0.5%	21.3.d.(vi)	C and D PPMs	3

Table 38: Parameters for Power Factor Control Mode

Justification

The reactive power requirements are determined by local factors and depend highly on the subset of generators and loads connected to local transmission/distribution system and the supplementary reactive power consumption of overhead lines and cables. To meet the local needs in terms of reactive power requirement in power factor control mode the target power factor is proposed to be site-specific.

Consultation Submissions

Submission 1

One respondent comments that they do not disagree with the proposal but note that the time to reach the target does not need to be site-specific.

SO Comments

The time period to reach the set point (target value) aligns now with the requirements for the voltage control mode (see section 5.2.2.5.1). The tolerance of the target power factor is 0.5%.

5.2.3 Voltage Control System for SPGM

5.2.3.1 Article 19.2.a and 19.2.b.(v)

Non-Exhaustive Parameter Selection

Applies to Type D SPGMs

Requirement

In relation to voltage stability, power-generating facility owner and the relevant system operator, in coordination with the relevant TSO, shall agree on the parameters and settings of the components of the voltage control system. The agreement shall cover the specifications and performance of an automatic voltage regulator ('AVR') with regard to steady-state voltage and transient voltage control (site-specific non-exhaustive Parameter). Further the specifications and performance of the excitation control system of an automatic voltage regulator shall include a Power System Stabilizer (PSS) function to attenuate power oscillations, among other, if the synchronous power-generating modules size is above the value proposed by the TSO.

Proposal

Parameter	Parameter in RfG	Proposal	Article Number	Type Applicability	Justification Code
Power Threshold	Not specified	All Type D PGMs	19.2.b.(v)	D SPGMs	2

Table 39: Power Threshold above which PSS Function is required

Justification

Due to the increasing complexity of the Transmission System, along with the increasing levels of non-synchronous generation, it is likely the frequency and intensity of oscillations will increase. In order manage this going forward and to maintain the security and safety of the Transmission System, PSSs will be required on all type D PGMs.

5.2.4 Fault Ride Through Capability

The following sections discuss the fault ride through (FRT) capability requirements under RfG. The requirements for SPGM and PPMs are discussed separately under each of these two sections.

It should be noted that the capabilities are different for different connection types. The requirements are split out in the following sections to indicate this. The relevant elements of a connection for this discussion are:

1. Connection at 110 kV or more
2. Connection at less than 110 kV
3. Different topology connections at less than 110 kV.

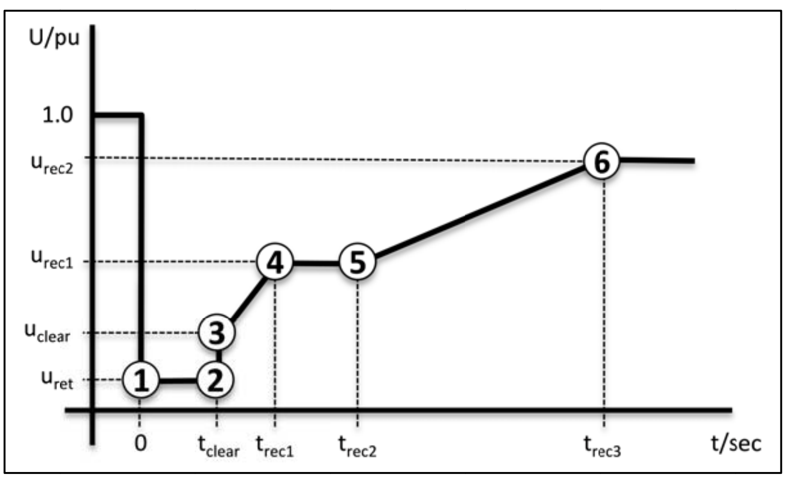
5.2.4.1 Article 14.3.a & 16.3.a: FRT Capability for PGMs connected at voltage level <110 kV

Non-Exhaustive Parameter Selection

Applies to Type B, C and D PGMs and offshore PPMs

Requirement

Power-generating modules shall be capable of staying connected to the network and continuing to operate stably after the power system has been disturbed by secured faults. That capability shall be in accordance with a voltage-against-time profile at the connection point for fault conditions in line with the figure below:



Fault Ride Through Profile of a Power-Generating Module

The voltage-against-time-profile shall express a lower limit of the actual course of the phase-to-phase voltages on the network voltage level at the connection point during a symmetrical (14.3.a and 16.3.a) and asymmetrical (Article 14.3.b and 16.3.c) fault, as a function of time before, during and after the fault.

That lower limit is specified for synchronous power-generating modules and power park modules connected below the 110 kV level in the following subsections.

Proposal: SPGMs connected at a voltage level < 110 kV

Table 40 lists the parameters which describe the FRT capability parameters for SPGMs connection at a voltage level < 110 kV.

No. on Graph	Parameter	Parameter in RfG	Proposal	Article Number	Type Applicability	Justification Code
1	u_{ret}	0.05 – 0.3 p.u.	0.05 p.u.	14.3.a (i)	B,C, and D SPGMs	2
2	u_{ret}	0.05 – 0.3 p.u.	0.05 p.u.			
	t_{clear}	140 – 250 ms	150 ms			
3	u_{clear}	0.7 – 0.9 p.u.	0.7 p.u.			
	t_{clear}	140 – 250 ms	150 ms			
4	u_{rec1}	u_{clear}	u_{clear}			
	t_{rec1}	t_{clear}	t_{clear}			
5	u_{rec1}	u_{clear}	u_{clear}			
	t_{rec2}	t_{rec1} – 700 ms	450 ms			
6	u_{rec2}	0.85 – 0.9 p.u.	0.9 p.u.			
	t_{rec3}	t_{rec2} – 1.5 s	t_{rec2}			

Table 40: Definition of FRT parameters for SPGMS connected @ <110 kV

Justification: SPGMs connected at a voltage level <110 kV

A change is needed here to comply with RfG. The points (150ms, 0.5 p.u.) and (450 ms, 0.5 p.u.) have to move to (150 ms, 0.7 p.u.) and (450 ms, 0.9 p.u.), respectively in order to come within the stipulated envelope.

Figure 7 shows the fault ride through capabilities including for completeness, the under-voltage protection settings (UV trip area) and RfG boundaries.

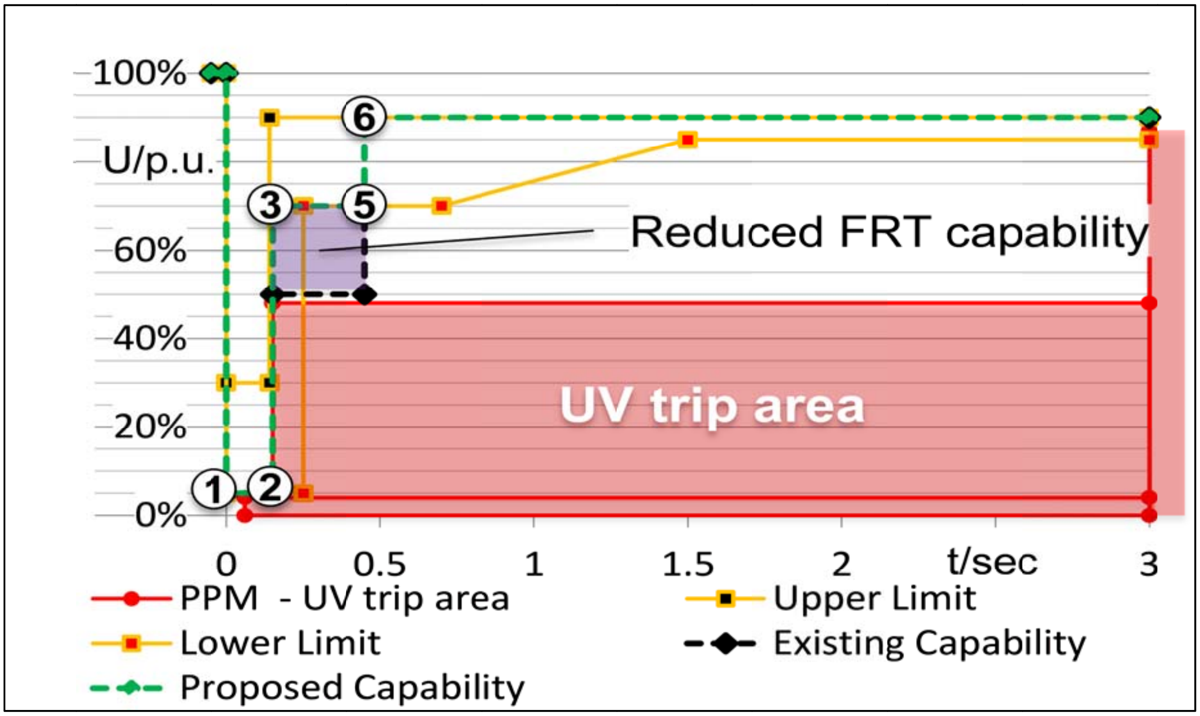


Figure 7: FRT capability for SPGMS connected @ <110 kV

Consultation Submissions:

Submission 1

One respondent commented that the rotor angle stability of SPGMs should be considered and that an upper limit of 0.3 p.u. could be chosen. They comment that the active power operating point and under-excited operation affects the FRT performance. However Voltage dips up to 0.3 p.u. for SPGMs have been successfully tested and that is why a limit of 0.3 p.u. is recommended.

SO Comments

This is the outcome of a recent CRU approved DCRP modification to align the Distribution and Grid Code requirements for fault ride through of SPGMs.

Submission 2

One respondent commented that the value of U_{ret} is too low and t_{clear} is too long for SPGMs to stay synchronised. These values could cause damage to equipment. They also comment that a SPGM could not pass a test designed to prove this compliance.

SO Comments

This is the outcome of a recent CRU approved DCRP modification to align the Distribution and Grid Code requirements for fault ride through of SPGMs.

Submission 3

One respondent commented that whilst there is an ability to develop bespoke combinations of prime-movers and alternators jointly controlled by a single encompassing regulator to form a special SPGM to meet the U_{ret} of 0.15%, this is costly and complex. They also comment that small manufacturing companies will not have the required equipment, technologies or budget to design these SPGMs. They suggest that this will impact competitiveness in the Type B manufacturing area which is contrary to the ENTSO/e objective of facilitating a competitive energy market. They suggest a U_{Ret} of 0.3 p.u. for a duration of <150ms as the most realistic value to ensure availability without loss of synchronization.

SO Comments

This is the outcome of a recent CRU approved DCRP modification to align the Distribution and Grid Code requirements for fault ride through of SPGMs.

Submission 4

One respondent commented that these values (and specifically the 5% U_n) are compatible with installation of a generating unit in a prevalent grid, which for a unit of approx. 5-10 MW corresponds to a 100 MW grid. When the grid power becomes comparable with the power of the generating unit, strong voltage dip can lead to oscillations or instability.

They comment that the 5% Un is more linked to a Transmission System fault near the substation. They suggest that for the distribution system a 30% recommended value is proposed. They comment that this value is used as a base reference in several countries including Belgium (ELIA).

SO Comments

This is the outcome of a recent CRU approved DCRP modification to align the Distribution and Grid Code requirements for fault ride through of SPGMs.

Submission 5

One respondent commented that RfG Article 6.3 states that PGMs installed in industrial installation have the right to agree on different conditions for disconnecting from the grid to preserve the industrial process. They suggest that Article 6.3 should be considered and explicitly referenced in the Grid Code.

SO Comments

The respondent is correct in that the RfG text states that:

…. "**relevant system operators** whose network is connected to the network of an industrial site shall have the right to agree on conditions for disconnection of such power-generating modules together with critical loads, which secure production processes.

Just for clarity, the right with is the RSO to agree this. ESBN is happy to enter into discussions with any customer in this regard.

Proposal: PPMs connected at a voltage level < 110 kV

Table 41 lists the parameters which describe the FRT capability parameters for SPGMs connection at a voltage level < 110 kV.

No. on Graph	Parameter	Parameter in RfG	Proposal	Article Number	Type Applicability	Justification Code
1	u_{ret}	0.05 – 0.15 p.u.	0.15 p.u.	14.3.a (i)	B,C and D PPMs	2
2	u_{ret}	0.05 – 0.15 p.u.	0.15 p.u.			
	t_{clear}	140 – 250 ms	250 ms			
3	u_{clear}	u_{ret} – 0.15 p.u.	u_{ret}			
	t_{clear}	t_{clear}	t_{clear}			
4	u_{rec1}	u_{clear}	u_{clear}			
	t_{rec1}	t_{clear}	t_{clear}			
5	u_{rec1}	u_{clear}	u_{clear}			
	t_{rec2}	t_{rec1}	t_{rec1}			
6	u_{rec2}	0.85 p.u.	0.85 p.u.			
	t_{rec3}	1.5 – 3.0 s	2.9 s			

Table 41: Definition of FRT parameters for PPMs connected @ <110 kV

Justification: PPMs connected at a voltage level <110 kV

Fault ride through capability changes slightly. Point (2) to (5) at (625 ms, 0.15 p.u.) moved to (250 ms, 0.15 p.u.). This will give a greater margin between this point and the under-voltage setting of 0.13 p.u. for 0.5s. Figure 8 shows the fault ride through capabilities including for completeness, the under-voltage protection settings (UV trip area) and RfG boundaries.

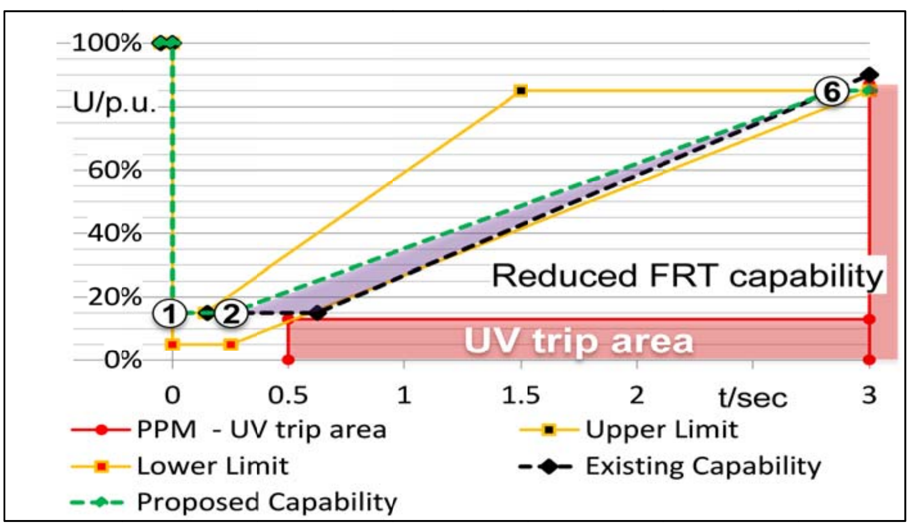


Figure 8: FRT capability PPM connected @ <110 kV

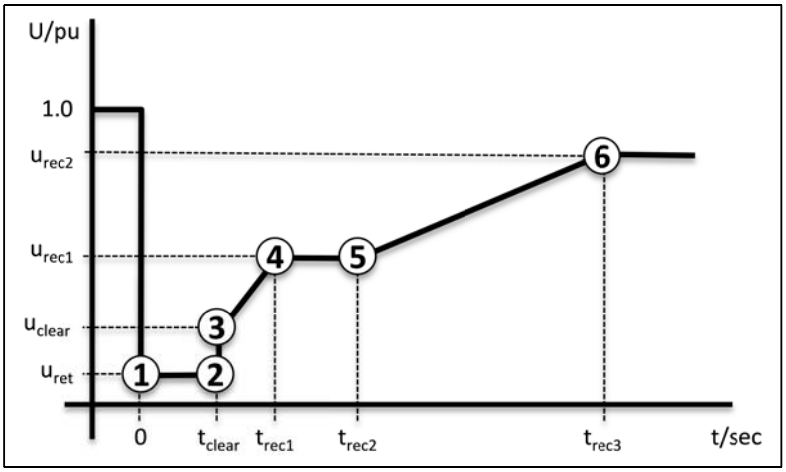
5.2.4.2 Article 16.3.a & 16.3.c FRT Capability for PGMs connected at voltage level ≥110 kV

Non-Exhaustive Parameter Selection

Applies to Type D PGMs and offshore PPMs

Requirement

Power-generating modules shall be capable of staying connected to the network and continuing to operate stably after the power system has been disturbed by secured faults. That capability shall be in accordance with a voltage-against-time profile at the connection point for fault conditions in line the figure below.



Fault Ride Through Profile of a Power-Generating Module

The voltage-against-time-profile shall express a lower limit of the actual course of the phase-to-phase voltages on the network voltage level at the connection point during a symmetrical (Article 16.3.a) and asymmetrical (Article 16.3.c) fault, as a function of time before, during and after the fault.

That lower limit is specified for synchronous power-generating modules and power park modules connected at or above 110 kV in the following subsections.

Proposal: SPGMs connected at a voltage level ≥ 110 kV

Table 42 lists the parameters which describe the FRT capability parameters for SPGMs connection at a voltage level ≥ 110 kV.

No. on Graph	Parameter	Parameter in RfG	Proposal	Article Number	Type Applicability	Justification Code
1	u_{ret}	0 p.u.	0	16.3.a (i)	D SPGMs	2
2	u_{ret}	0 p.u.	0			
	t_{clear}	140 – 250 ms	150 ms			
3	u_{clear}	0.25 p.u.	0.25 p.u.			
	t_{clear}	140 – 250 ms	150 ms			
4	u_{rec1}	0.5 – 0.7 p.u.	0.5 p.u.			
	t_{rec1}	t_{clear} – 450 ms	450 ms			
5	u_{rec1}	0.5 – 0.7 p.u.	0.5 p.u.			
	t_{rec2}	t_{rec1} – 700 ms	450 ms			
6	u_{rec2}	0.85 – 0.9 p.u.	0.9 p.u.			
	t_{rec3}	t_{rec2} – 900 ms	450 ms			

Table 42: Definition of FRT parameters for SPGMs connected @ □110 kV

Justification: SPGMs connected at a voltage level ≥110 kV

According to the RfG parameters, the retained voltage (u_{ret}) is stipulated to be 0.0 p.u. The recovery voltage has been capped to the upper bound of u_{rec2} of 0.9 p.u. Figure 9 shows the fault ride through capabilities including for completeness, the RfG boundaries.

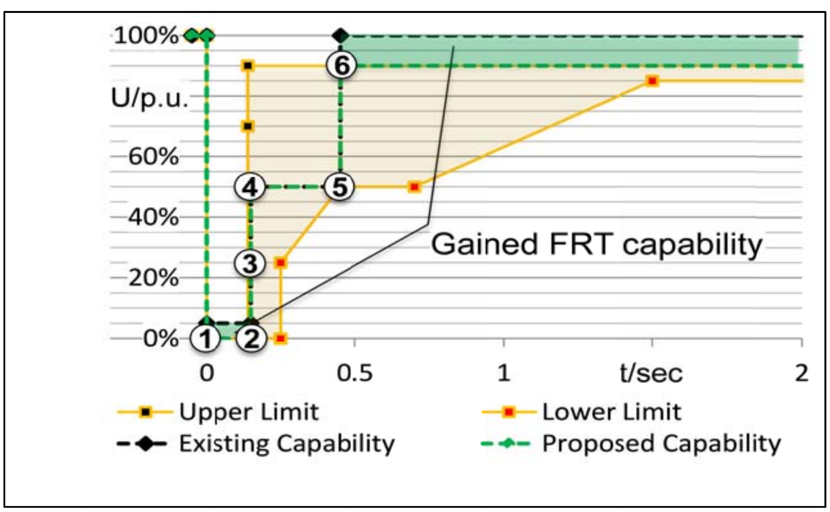


Figure 9: FRT capability of SPGMs connected at ≤ 110 kV

Consultation Submissions

Submission 1

One respondent requests clarity on whether the proposals here apply also to asymmetrical faults.

SO Comments

The generators shall remain connected to the Transmission System for transmission or distribution system voltage dips. This is as per the current Grid Code requirements.

According to the Grid Code, the voltage dip is a short duration reduction in voltage on any or all phase due to a fault distrained or significant system incident, resulting in transmission voltage outside the specified range.

Hence, the FRT requirement is applicable for symmetric (Article 16.3.a) and asymmetrical (Article 16.3.c) faults.

Submission 2

One respondent commented that these values (and specifically the 25% Un, 450ms) are compatible with installation of a generating unit in a prevalent grid, which for a unit of approx. 5-10 MW corresponds to a 100 MW grid. When the grid power becomes comparable with the power of the generating unit, strong voltage dip can lead to oscillations or instability.

SO Comments

Noted.

Submission 3

One respondent commented that RfG Article 6.3 states that PGMs installed in industrial installation have the right to agree on different conditions for disconnecting from the grid to preserve the industrial process. They suggest that Article 6.3 should be considered and explicitly referenced in the Grid Code.

SO Comments

The SO notes this comment that RfG art 6.3 gives generators the right to ask for industry specific requirements. This will be considered during the Grid and Distribution Code modification process.

Proposal: PPMs connected at a voltage level ≥ 110 kV

Table 43 lists the parameters which describe the FRT capability parameters for SPGMs connection at a voltage level < 110 kV.

No. on Graph	Parameter	Parameter in RfG	Proposal	Article Number	Type Applicability	Justification Code
1	u_{ret}	0 p.u.	0	16.3.a (i)	D PPMs	2
2	u_{ret}	0 p.u.	0			
	t_{clear}	140 – 250 ms	150 ms			
3	u_{clear}	u_{ret}	u_{ret}			
	t_{clear}	t_{clear}	t_{clear}			
4	u_{rec1}	u_{clear}	u_{clear}			
	t_{rec1}	t_{clear}	t_{clear}			
5	u_{rec1}	u_{clear}	u_{clear}			
	t_{rec2}	t_{rec1}	t_{rec1}			
6	u_{rec2}	0.85 p.u.	0.85 p.u.			
	t_{rec3}	1.5 – 3.0 s	2.9 s			

Table 43: Definition of FRT parameters for PPMs connected @ ≥ 110 kV

Justification: PPMs connected at a voltage level ≥110 kV

According to the RfG parameters, the retained voltage (u_{ret}) is stipulated to be 0.0 p.u. Figure 10 shows the fault ride through capabilities including for completeness, the under-voltage settings in the distribution system and the RfG boundaries.

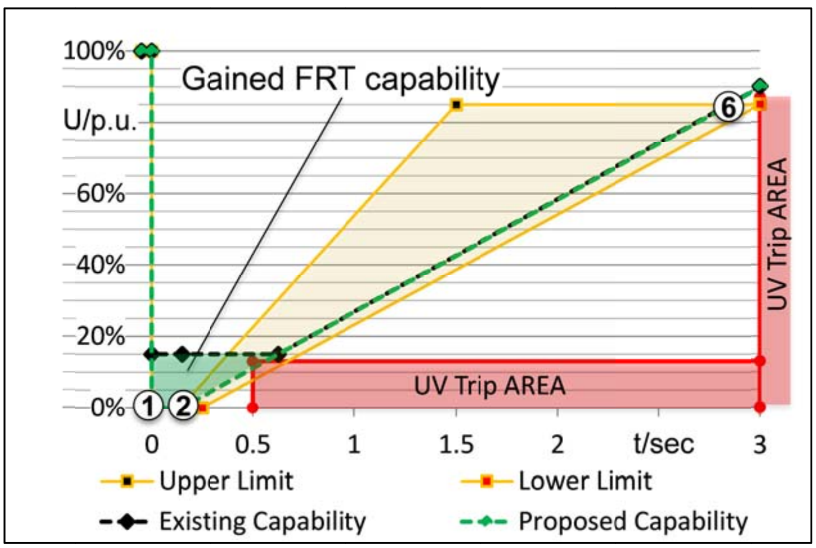


Figure 10: FRT capability of PPMs connected at ≤ 110 kV

It is noted that these proposed FRT capability requirements, conflict with the current protection settings for under voltage relays. However in the future, these protection settings may change and the FRT capability needs to remain.

Consultation Submissions

Submission 1

One respondent requests clarity on whether the proposals here apply also to asymmetrical faults.

SO Comments

The generators shall remain connected to the Transmission System for transmission or distribution system voltage dips. This is as per the current Grid Code requirements.

According to the Grid Code, the voltage dip is a short duration reduction in voltage on any or all phase due to a fault distrained or significant system incident, resulting in transmission voltage outside the specified range.

Hence, the FRT requirement is applicable for symmetric (Article 16.3.a) and asymmetrical (Article 16.3.c) faults.

Submission 2

One respondent commented that converter based technologies may have difficulties meeting the required proportional current injection levels for such low values of voltage as this may cause converter instability. They suggest that the proposals are limited to a voltage level of 0.15pu where the units are required to inject P and i_q

SO Comments

Uret is an exhaustive parameter and specified in the RfG for type D PPM connected @ voltage level ≥110 kV. The value specified is Uret = 0 p.u. (see Article 16.3 (a) (i) and Table 7.2) Hence, the proposed value is in breach with the RfG requirements. "

5.2.4.3 Fast Fault Current Injection

5.2.4.3.1 Article 20.2.b Fast Fault Current Injection for Symmetrical Faults

Non-Exhaustive Parameter Selection

Applies to Type B, C and D PPM

Requirement

the relevant system operator in coordination with the relevant TSO shall have the right to specify that a power park module be capable of providing fast fault current at the connection point in case of symmetrical (3-phase) faults, under the following conditions

(i) the power park module shall be capable of activating the supply of fast fault current either by:
   a. ensuring the supply of the fast fault current at the connection point, or
   b. measuring voltage deviations at the terminals of the individual units of the PPM and providing a fast fault current at the terminals of these units;

(ii) the relevant system operator in coordination with the relevant TSO shall specify:
   a. how and when a voltage deviation is to be determined as well as the end of the voltage deviation,
   b. the characteristics of the fast fault current, including the time domain for measuring the voltage deviation and fast fault current, for which current and voltage may be measured differently from the method specified in Article 2,
   c. the timing and accuracy of the fast fault current, which may include several stages during a fault and after its clearance;

Proposal

Parameter	Parameter in RfG	Proposal	Article Number	Type Applicability	Justification Code
Voltage threshold for fast fault current injection	Not specified	During voltage dips i.e. when the voltage is below 0.9 p.u.	20.2.b	B, C and D PPMs	1
End of the voltage deviation	Not specified	Once the voltage has recovered to within normal operating voltage range	20.2.b	B, C and D PPMs	1
the characteristics of the fast fault current, including the time domain for measuring the voltage deviation and fast fault current	Not specified	Reactive current should be provided for the duration of the voltage deviation within the rating of the PPM	20.2.b	B, C and D PPMs	1
the timing and accuracy of the fast fault current, which may include several stages during a fault and after its clearance	Not specified	Rise Time no greater than 100ms and a Settling Time no greater than 300ms.	20.2.b	B, C and D PPMs	2

Table 44: Fast Fault Current Injection - Symmetrical Faults

Justification:

As per the current Grid Code requirements, the fast fault current injection shall be provided during Transmission System voltage dips. Voltage dips can occur following a transmission or distribution fault, or more generally, where bus voltages and terminal voltage of less than 90% nominal voltage on any or all phases occur. CC.8.3.2 specifies the Transmission System disturbance voltages following transmission faults.

According to WFPS1.4.2, the provision of reactive current shall continue until the Transmission System voltage recovers to within the normal operational range as specified in CC8.3.1, or for at least 500 ms, whichever is sooner. The reactive current response shall be supplied within the rating of PPM, with a Rise Time no greater than 100ms and a Settling Time no greater than 300ms.

Consultation Submissions: End of Voltage Deviation

Submission 1

One respondent commented that more clarity is required in relation to what normal operating voltage range is.

SO Comments

Normal operating range is specified from 0.9 p.u. to 1.118 p.u. as per RfG (see Article 16 2 (a) (i)). This is a mandatory and exhaustive parameter which does not form a part of this proposal document.

Consultation Submissions: the timing and accuracy of the fast fault current, which may include several stages during a fault and after its clearance

Submission 1

One respondent questioned whether this had been discussed and agreed with the OEMs.

SO Comments

This requirement is as per today's Grid Code requirements (WFPS1.4.2 c).

5.2.4.3.2 Article 20.2.c Fast Fault Current Injection for Asymmetrical Faults

Non-Exhaustive Parameter Selection

Applies to Type B, C and D PPM

Requirement

(iii) with regard to the supply of fast fault current in case of asymmetrical (1-phase or 2-phase) faults, the relevant system operator in coordination with the relevant TSO shall have the right to specify a requirement for asymmetrical current injection

Proposal

Parameter	Parameter in RfG	Proposal	Article Number	Type Applicability	Justification Code
Voltage threshold for fast fault current injection	Not specified	During voltage dips i.e. when the voltage is below 0.9 p.u.	20.2.b	B, C and D PPMs	1
the characteristics of the fast fault current, including the time domain for measuring the voltage deviation and fast fault current	Not specified	Reactive current should be provided for the duration of the voltage deviation within the rating of the PPM	20.2.b	B, C and D PPMs	1
the timing and accuracy of the fast fault current, which may include several stages during a fault and after its clearance	Not specified	Rise Time no greater than 100ms and a Settling Time no greater than 300ms.	20.2.b	B, C and D PPMs	2

Table 45: Fast Fault Current Injection - Asymmetrical Faults

Justification:

As per the current Grid Code requirements, the fast fault current injection shall be provided during Transmission System voltage dips. Voltage dips can occur following a transmission or distribution fault, or more generally, where bus voltages and terminal voltage of less than 90% nominal voltage on any or all phases occur. CC.8.3.2 specifies the Transmission System disturbance voltages following transmission faults.

According to WFPS1.4.2 of the Grid Code and DCC11.2.2 of the Distribution Code, the provision of reactive current shall continue until the Transmission System voltage recovers to within the normal operational range as specified in CC8.3.1, or for at least 500 ms, whichever is sooner. The reactive current response shall be supplied within the rating of PPM, with a Rise Time no greater than 100ms and a Settling Time no greater than 300ms.

Consultation Submissions: the timing and accuracy of the fast fault current, which may include several stages during a fault and after its clearance

<u>*Submission 1*</u>

One respondent questioned whether this had been discussed and agreed with the OEMs.

SO Comments

This requirement is as per today's Grid Code requirements (WFPS1.4.2 c) and applies for symmetrical and asymmetrical faults. The requirements are as follows:

The reactive current response shall be supplied within the rating of the Controllable WFPS, with a Rise Time no greater than 100ms and a Settling Time no greater than 300ms.

5.2.4.4 Article 20.3.a Post-Fault Active Power Recovery for PPMs

Non-Exhaustive Parameter Selection

Applies to Type B, C and D PPM

Requirement

(a) the relevant TSO shall specify the post-fault active power recovery that the power park module is capable of providing and shall specify certain parameters

Proposal

Table 46 details the specification of post fault active power recovery capability that power park module shall be capable of providing.

Parameter	Parameter in RfG	Proposal	Article Number	Type Applicability	Justification Code
when the post-fault active power recovery begins, based on a voltage criterion	Not specified	u_n< 0.9 p.u.	20.3.a	B, C and D PPMs	**1**
maximum allowed time for active power recovery	Not specified	500ms/1s	20.3.a	B, C and D PPMs	**1**
magnitude and accuracy for active power recovery	Not specified	90%	20.3.a	B, C and D PPMs	**1**

Table 46: Post-Fault Active Power Recovery for PPMs

Justification

These proposals are as per the current Grid Code WFPS.1.4.2 b) of the Grid Code and DCC11.2.2 of the Distribution Code. The maximum allowed time for active power recovery differs between fault clearance within 140 ms of 500 ms and for longer clearance times of 1 second.

Consultation Submissions

Submission 1

One respondent comments that they agree with the proposal but they note that the proposal should be 90% of Power Available rather than 90% of the pre-disturbance power level as the available power may have reduced during the disturbance for PPMs with fluctuating resource.

SO Comments

The SOs note this comment and this will be considered during the Grid and Distribution Code modification process.

5.2.4.5 Article 21.3.e Priority Given to Active or Reactive Power Contribution for PPMs

Non-Exhaustive Parameter Selection

Applies to Type C and D PPMs

Requirement

With regard to prioritising active or reactive power contribution, the relevant TSO shall specify whether active power contribution or reactive power contribution has priority during faults for which fault-ride-through capability is required. If priority is given to active power contribution, this provision has to be established no later than 150 ms from the fault inception;

Proposal

Table 47 specifies the priority to power contribution during faults for which fault-ride-through capability is required. If priority is given to active power contribution, this provision has to be established no later than 150 ms from the fault inception.

Parameter	Parameter in RfG	Proposal	Article Number	Type Applicability	Justification Code
Prioritisation requirements during FRT	Active/Reactive	Active	21.3.e	C and D PPMs	1

Table 47: Priority given to Active or Reactive Power Contribution

Justification

The proposal aligns with WFPS.1.4.2 of the Grid Code which stipulates that priority shall always be given to the active power response during and after faults within the capabilities of the PPM.

5.2.5 Additional Non-Mandatory Voltage Requirements

There is one remaining non-mandatory requirements detailed in the RfG. Table 48 below identifies the area. We do not intend to invoke this non-mandatory requirement at this time.

Requirement	Requirement in RfG	Proposal	Article Number	Type Applicability
Simultaneous overvoltage and under frequency or simultaneous under voltage and over frequency	Do we want to expertise the right to specify this non-mandatory RfG?	Not invoking at this time.	16(02)(a)(ii)	Type A, B, C and D PGMs

Table 48: List of Non-Mandatory and not invoked Requirements for Generators

5.3 System Restoration Theme

There is only one Article in RfG with a non-exhaustive parameter under the system restoration theme. The sub theme is on:

- Operation of PGM following tripping to house load.

5.3.1 Operation following tripping to house load

5.3.1.1 15.5.c. (iii) Operation following tripping to house load

Non- Exhaustive Parameter Selection

Applies to Types C and D PGMs and offshore PPMs

Requirement

A power-generating module with a minimum re-synchronisation time greater than 15 minutes after its disconnection from any external power supply must be designed to trip to house load from any operating point in its P-Q-capability diagram. In this case, the identification of house load operation must not be based solely on the system operator's switchgear position signals. Power-generating modules shall be capable of continuing operation following tripping to house load, 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

Proposal

Parameter	Parameter in RfG	Proposal	Article Number	Type Applicability	Justification Code
Operation Following Tripping to House Load	Not Specified	4 hours	15.5.c.iii	C and D PGMs and offshore PPMs with a minimum re-synchronisation time greater than 15 minutes*	2/3

Table 49: Operation Following Tripping to House Load

Justification

The Grid Code currently requires generators with a startup time in excess of 20 minutes to be capable of tripping to house load and remain there indefinitely. The RfG requirements are stated differently. Firstly, the requirement applies to Type C & D PGMs with a minimum re-synchronisation time greater than 15 minutes and secondly the time to remain in the mode must be specified by the TSO. For the purpose of this consultation the only item being consulted on is the operation time following tripping to house load. The TSO proposes 4 hours which is aligned to the time to during which units may be without external supply under the Power System Restoration Plan. The Power System Restoration Plan envisages the system being re-synchronised within 4 hours.

Consultation Submissions

Submission 1

Two respondents commented that they are assuming that faster synchronizing units (< 15 min) do not fall into this requirement. They requested a clarification that units with less than 15min re-synchronization time are not required to have 4hours operation time on house load. They further requested that if they need to comply, can we change this time from 4 hours to 2 hours?

SO Comments

Yes, your understanding is correct.

If a synchronisation time for a PGM is less than 15 minutes, they are not required to have an operating time in house load of 4 hours. In fact, under RfG, PGMs with synchronisation times of less than 15 minutes are not required to be able to trip to house load.

Where PGMs have synchronisation times of 15 minutes or more, they must be capable of remaining in house load operation for a period of time. The TSO are proposing 4 hours. The reason for this is to align with the Blackstart plan. If the period for house load operation was less than 4 hours, it would not be sufficient, under the Blackstart plan, to resynchronise the PGM to the Transmission System and would result in the PGM tripping off and going cold, which lead to a longer resynchronisation time and would further delay to the overall system restoration.

5.5 Protection and Instrumentation Theme

The non-exhaustive and non-mandatory protection and instrumentation parameters cover a number of different requirements. The following sub-themes are discussed in the next sections:

- Manual Local Measures where the automatic remote devices are out of service
- Instrumentation
- Dynamic system behaviour monitoring
- Simulations
- Neutral Earthing
- Synthetic Inertia

5.5.1 Manual, local measures

5.5.1.1 Article 15.2.b: Manual, local measures

Non- Exhaustive Parameter Selection

Applies to Types B, C and D PGMs

Requirement

Manual local measures shall be allowed in cases where the automatic remote control devices are out of service.

The relevant system operator or the relevant TSO shall notify the regulatory authority of the time required to reach the set point together with the tolerance for the active power.

Proposal

Parameter	Parameter in RfG	Proposal	Article Number	Type Applicability	Justification Code
Time required to achieve setpoint when automatic remote devices are unavailable	Not Specified	1 hour	15(2)(b)	B, C and D PGMs	3

Table 50: Time required to Achieve Set point when Automatic Remote Devices are Unavailable

Justification:

While this is a new requirement for PGMs in terms of the Grid Code, it is an existing requirement under the Distribution Code (DCC.11.5.2.6.2) which states that for PPMs, a responsible operator shall be present at the connection point within one hour and shall be capable of taking the required appropriate actions.

The proposed value of 1 hour as the time required to achieve set point when automatic remote devices are unavailable is intended to allow the operator a reasonable time to reach the site, while also ensuring consistency between the Grid and Distribution Codes.

Consultation Submissions

Submission 1

Two respondents commented that their main issue here is to get the set point to the generating unit. They suggest that the proposal of 1 hour can be a target value.

SO Comments

While we understand that accessing some sites within an hour may be difficult, the proposal aligns with the current requirements for the Blackstart plan Grid Code requirements which require that all sites should be staffed within 1 hour. As such, all best endeavours should be made to attend site within the required time of 1 hour.

5.5.2 Instrumentation: Quality of Supplies

5.6.2.1 Article 15.6.b (i): Instrumentation: Quality of Supplies

Non-Mandatory Requirement being made Mandatory

Applies to Types C and D PGMs and offshore PPMs

Requirement

Power-generating facilities shall be equipped with a facility to provide fault recording and monitoring of dynamic system behaviour. This facility shall record the following parameters:

- Voltage,
- Active power,
- Reactive power, and
- Frequency

The relevant system operator shall have the right to specify quality of supply parameters to be complied with on condition that reasonable prior notice is given.

Proposal

Requirement	Requirement in RfG	Proposal	Article Number	Type Applicability	Justification Code
Quality of supplies parameters to be recorded.	Not Specified	Site Specific	15(6)(b)(i)	C and D PGMs and offshore PPMs	3

Table 51: Quality of Supplies Parameters to be Recorded

Justification:

This requirement will need to be implemented on a site specific basis due to:

- Varying station and/or generation unit configurations and generation types.
- Compatibility with existing equipment

5.5.3 Dynamic System Behaviour Monitoring

5.6.3.1 Article 15.6.b. (iii): Dynamic System Behaviour Monitoring

Non-Exhaustive Parameter Selection

Applies to Types C and D PGMs and offshore PPMs

Requirement

The dynamic system behaviour monitoring shall include an oscillation trigger specified by the relevant system operator in coordination with the relevant TSO, with the purpose of detecting poorly damped power oscillations;

Proposal

Parameter	Parameter in RfG	Proposal	Article Number	Type Applicability	Justification Code
Oscillation trigger detecting poorly damped power oscillations.	Not Specified	Site Specific	15(6)(b)(iii)	C and D PGMs and offshore PPMs	3

Table 52: Oscillation Trigger Detecting Poorly Damped Power Oscillations

Justification

This requirement will need to be implemented on a site specific basis due to:

- Varying station and/or generation unit configurations and generation types.
- Compatibility with existing equipment

5.5.4 Simulation Model Provision

5.6.4.1 Article 15.6.c. (iii): Simulation Model Provision

Non-Mandatory Requirement being made Mandatory

Applies to Types C and D PGMs and offshore PPMs

Requirement

The request by the relevant system operator referred to in point (i) shall be coordinated with the relevant TSO. It shall include:

- The format in which models are provided,
- The provision of documentation on a model's structure and block diagrams,
- An estimate of the minimum and maximum short circuit capacity at the connection point, expressed in MVA, as an equivalent of the network.

Proposal

Requirement	Requirement in RfG	Proposal	Article Number	Type Applicability	Justification Code
Model Provision	Not Specified	Retain the existing model provision requirements with the inclusion of min and max short circuit levels as part of Grid Code Planning Code Appendix Generator Data Requirements	15(6)(c)(iii)	C and D PGMs and offshore PPMs	3

Table 53: Simulation Model Provision

Justification

Grid Code PC.A4 to PC.A8 defines the format of the models to provided, along with details of the supporting documentation. Any information that is required to be provided to the customer will be provided through the current pre-energisation process. This will be provided to the user up to two years in advance of connection, along with the minimum short circuit level as a per unit value.

The proposal is to retain the existing PCA but with the inclusion of additional fields for the provision of the min and max short circuit levels in MVA.

Consultation Submissions

Submission 1

One respondent commented that the Grid Code should provide more information about excitation and turbine governor model for PGMs that are not in the IEEE standard block diagram. They requested more clarification on whether block diagrams, description and parameters would be sufficient or not. They also request how detailed the model should be for each type of study and how the IPP is protected.

SO Comments

Block diagrams, description and parameters should be sufficient as long as the user provides information including, but not limited to, a full description of the Model structure and functionality, Laplace diagrams or other suitably understandable information as per PC.A8.3. The detail of the model should be sufficient so that the behaviour of the Plant is represented in balanced, root mean-square, positive phase-sequence, time-domain studies and where specified, electromagnetic transient and harmonic studies as per PC.A8.2. Confidentiality is discussed in section PC.A8.4.

Submission 2

One respondent requested clarification on whether they can supply simplified block diagrams from both the AVR and Engine. They also suggested that for EMT or RMS simulations that a locked model in Power Factory format could be provided (due to IP restrictions).

SO Comments

Block diagrams, description and parameters should be sufficient as long as the user provides information including, but not limited to, a full description of the Model structure and functionality, Laplace diagrams or other suitably understandable information as per PC.A8.3

The detail of the model should be sufficient so that the behaviour of the Plant is represented in balanced, root mean-square, positive phase-sequence, time-domain studies and where specified, electromagnetic transient and harmonic studies as per PC.A8.2. Confidentiality is discussed in section PC.A8.4

In terms of the locked model, provided the model is representative of the generator's performance (during testing and normal operation) and is compatible with our software environments then this should not be an issue. We have accepted this in the past.

Submission 3

One respondent commented that Min/max short circuit contribution come from generator data sheet and AVR limits. They comment that this is already a part of the documentation that is currently requested.

SO Comments

That is correct but not measured in MVA. The inclusion of the additional two fields in the PCA will address this and will only require the conversion of the short circuit levels, as are currently provided, into MVA.

5.5.5 Neutral-point at the network side of step transformers

5.6.5.1 Article 15.6.f.: Neutral-point at the network side of step transformers

Non-Exhaustive Parameter Selection

Applies to Types C and D PGMs and offshore PPMs

Requirement

Earthing arrangement of the neutral-point at the network side of step-up transformers shall comply with the specifications of the relevant system operator.

Proposal

Parameter	Parameter in RfG	Proposal	Article Number	Type Applicability	Justification Code
Earthing arrangement of the neutral-point	Not Specified	400 kV – solidly earthed 220 kV – site specific 110 kV – site specific	15(6)(f)	C and D PGMs and offshore PPMs	1

Table 54: Neutral-point at the Network Side of Step Transformers

Justification:

The proposal is to maintain the proposed Grid Code standard as defined in CC.7.2.5.3.2 and CC.7.2.5.3.3. for 220 kV and 400 kV transformers respectively.

For 110 kV transformers, a modification to the existing text in the Grid Code was proposed at the GCRP, this has been further modified to specifically relate to demand customers and generator customers rather than the DSO. This proposal will be presented to the next GCRP meeting. The revised text of modification proposal (MPID 272), states:

"The ***TSO*** *will consider on a case by case basis the required treatment of the 110 kV neutral connection of these* ***Transformer****s.* ***.*** *A 110 kV Neutral Earth Switch may be required to be installed in specific instances and* ***Demand Customers*** *or* ***Generators,*** *as applicable, will be advised of this at the time of the* ***Connection Offer****. The* ***TSO*** *will be responsible for the status of the 110 kV Neutral Earth Switch on these* ***Transformer****s."*

It is already stated in the Distribution Code clauses listed below, that the neutral point of the HV side of a customer step-up transformer, at the connection point shall not under any circumstance, be earthed by the customer. The relevant existing Distribution Code clauses are: DCC6.3.4, DCC9.3.4, and DCC11.4.4

5.6.6 Additional Non-Mandatory Protection & Instrumentation Requirements

There are a number of additional areas with non-exhaustive parameters detailed in the RfG. Table 55 below identifies the areas. In all cases these requirements will be highly dependent on the type of PGM, the location of the connection, etc. As such, these requirements must be dealt with on a case by case basis and do not form part of this proposal document.

Parameter	Parameters in RfG	Article Number	Type Applicability
Control Scheme and Settings: Agreement and coordination between the TSO, the RSO (TSO and DSO) and the power generating facility owner (PGFO)	Control schemes and settings of the control devices	14.5.a	B,C and D PGMs and offshore PPMs
Electrical Protection Schemes and settings: Agreement and coordination between the RSO and the PGFO	Protection schemes and settings	14.5.b	B,C and D PGMs and offshore PPMs
Loss of angular stability or loss of control: Agreement between PGFO and the RSO (DSO or TSO), in coordination with the TSO	Criteria to detect loss of angular stability or loss of control	15.6.a	C and D PGMs and offshore PPMs
Instrumentation: Settings of the fault recording equipment, including triggering criteria and sampling rate **Agreement between the PGFO and the RSO (DSO or TSO), in coordination with the TSO.**	Settings of the fault recording equipment, including triggering criteria and sampling rate	15.6.b(ii)	C and D PGMs and offshore PPMs
Instrumentation: Protocols for recorded data **Agreement between PGFO, the RSO and the relevant TSO**	Protocols for recorded data	15.6.b(iv)	C and D PGMs and offshore PPMs
Installation of devices for system operations and system security: Agreement between RSO or TSO and PGFO	Definition of the devices needed for system operation and system security	15.6.d	C and D PGMs and offshore PPMs
Synchronisation: Agreement between the RSO and the PGFO	Settings of the synchronisation devices	16.4	D PGMs and offshore PPMs
Angular stability under fault conditions: Agreement between the TSO and PGFO	Agreement for technical capabilities of the power generating module to aid angular stability.	19.3	D SPGM

Table 55: Parameters to be agreed on a Case by Case basis

6. Conclusion

This concludes the joint submission of EirGrid and ESB Networks to the Commission for the Regulation of Utilities of the proposal for the general application of technical requirements in accordance with Articles 13 – 28 of the Commission Regulation (EU) 2016/631 establishing a network code on requirements for grid connection of generators

EirGrid and ESB Networks would now like to request the approval of the CRU for each of the requirements proposed in this document.

7. Appendix

The following appendix holds the submissions from industry in relation to the Consultation on the proposals within this document.

Renewable Energy Systems Limited
Willowbank Business Park, Millbrook, Larne,
County Antrim, Northern Ireland, BT40 2SF, United Kingdom
T +44 (0)28 2844 0580 F +44 (0)1923 299 299
E info@res-group.com, **www.res-group.com**

EirGrid

By email to gridcode@eirgrid.com

Our Ref: EN01-005648

9 February 2018

Dear Sir,

Re: RES Limited Response - Consultation on RfG Parameter Selection - Ireland

RES is the UK & Ireland's largest independent renewable energy developer with interests in energy storage, onshore wind, wave and tidal, offshore wind, solar and demand-side response. RES is at the forefront of innovation and design around the world, and now employs over 1000 people and has developed/built over 10,000MW of wind energy assets.

Since developing our first onshore wind farm in Ireland in the early 1990s, RES has subsequently developed and/or constructed 22 wind farms across the island totalling 318MW. RES currently operates over 118MW of wind capacity and has secured planning permission for a further 59MW under/awaiting construction and has 81MW in the planning system.

RES is one of the world's leading independent energy storage developers, with a global energy storage portfolio totalling more than 240 MW (275 MWh), providing multiple grid services. RES was identified by Navigant Research as one of the leading utility-scale energy storage integrators.

Based in Larne, County Antrim, RES' Ireland team comprises 20 staff covering environmental, planning, engineering, technical, legal, commercial, project management, construction, operations and administration disciplines.

RES is a member of the Irish Wind Energy Association (IWEA) and the Irish Solar Energy Association (ISEA).

This consultation response is not confidential.

We welcome the opportunity to provide comments to the EirGrid and ESB Networks' proposal dated 20th December 2017 (and updated with clarifications on 17th January 2018) for the general application of technical requirements in accordance with Articles 13-28 of the Commission Regulation (EU) 2016/631 establishing the network code on requirements for grid connection of generators. Please find attached document entitled "RES Ltd Response Republic of Ireland RfG Parameter Consultation" which contains our detailed comments.

The above-referred comments are offered in a spirit of positive cooperation and we will be happy to clarify any of the points raised in our consultation response.

Yours faithfully

Claver Chitambo
Senior Electrical Engineer, Ireland
T Claver.Chitambo@res-group.com
E +44 1788 220 789

Irish Solar Energy Association,
Ground Floor, Unit 1B,
Custom House Plaza 3,
IFSC,
Dublin 1,
Email: info@irishsolarenergy.org

ISEA
Irish Solar Energy Association

9th February 2018

Consultation Response to EirGrid and ESB Networks

Dear Sir/Madam,

ISEA welcome the opportunity to provide our views on EirGrid and ESB Networks' proposal for the general application of technical requirements in accordance with Articles 13-28 of the Commission Regulation (EU) 2016/631 establishing a network code on requirements for grid connection of generators published on 20th December 2017.

As the leading trade association for solar energy in Ireland, ISEA is responding on behalf of our membership of over 50 Irish businesses. ISEA recognise the Network Code on the Requirements for Grid Connections of Generators has entered force and applies across the European Union. ISEA also recognises that these requirements apply to generators with a Maximum Capacity of 800W.

Given the detailed technical nature of the material only the System Operators can provide informed commentary on what is appropriate for the Irish Electricity System. Nonetheless ISEA has a number of very serious concerns re the introduction of RfGs which we outline as follows:

- ISEA is very concerned that the adoption of the RfGs will lead to an increased technical and cost burden on micro and small generation projects. Increased costs will undermine the economics of a sector that is struggling to establish itself and could leave many small generation projects unviable.
- The 2015 Energy White Paper specifically calls for the engagement of citizens in our energy transition and it is essential that this overarching policy is not undermined or frustrated by technical standards.

- It is important that the RfGs are adapted in a sensible way that is appropriate for the Irish Electricity System. It is not good practice to introduce rules which shall require derogations for swathes of generators to be commercially viable.
- Increasing technical and cost requirements disadvantages new market entrants from those who have benefitted from established market practice. New entrants are penalised by being held to a higher technical threshold than existing projects with which they are competing. This undermines market principles and acts as a barrier to new entrants.
- ISEA is concerned that the application of the 1.1 pu limit (Umax) for 38kV and MV connections (Section 4.2.2.2. Reactive Power Capability at Maximum Capacity) could significantly disadvantage solar PV generators seeking connections to the Distribution System. Whilst the majority of solar PV generators will not result in long shallow connections, the application of such limits will most likely lead to 38kV line upgrades for embedded generators. Given the total cost of such upgrades are borne by the generator which triggers the upgrade, this would lead to an intolerable situation whereby solar PV projects will which would otherwise be delivered will become unviable. This cannot be permitted to occur.

It is essential that the solar PV projects currently being developed are not prejudiced by varying technical standards which are inappropriate for our specific circumstances. It is also essential that the ambitions of the 2015 Energy White Paper to specifically enable energy citizens are not frustrated. We urge EirGrid and ESB Networks to consider carefully the potential impacts of the RfGs on the emerging solar PV sector in Ireland and ensure technical standards are evolved to support our energy transition, rather than frustrate it.

Yours sincerely

Michael McCarthy
Chief Executive Officer

IWEA response to the consultations on EirGrid and ESB Networks' proposal for the general application of technical requirements in accordance with Articles 13-28 of the Commission Regulation (EU) 2016/631 establishing a network code on requirements for grid connection of generators

Introduction

The Irish Wind Energy Association (IWEA) is committed to the promotion and education of wind energy issues and plays a leading role in the areas of conference organisation, lobbying and policy development on the island of Ireland. IWEA is committed to promoting the use of wind energy in Ireland and beyond as an economically viable and environmentally sound alternative to thermal or nuclear generation.

IWEA welcomes the opportunity to respond to the System Operators consultations on Network Codes. IWEA supports the work the System Operators have undertaken to implement the Network Codes in Ireland. Although IWEA is generally supportive of the principle of having a European wide set of network codes for generators, it is also important that some of the historical and geographic characteristics of the Irish transmission and distribution networks are taken into account in the implementation of the network codes in Ireland.

IWEA has serious concerns on the implementation of some of the reactive power requirements. Although the modern generation technologies have the capability to the meet these reactive power requirement, IWEA is concerned that the requirements will impact on ESB Networks' planning standards for generator connections. The proposals in the ESB Networks and EirGrid's consultation on reactive power requirements for 38kV and MV connections will significantly impact on the capacity of renewable generation than can viably connect to the distribution system in the future. This have a huge bearing the viability of many embedded generation sites, the cost of electricity to the Irish consumer and the ability of Ireland to decarbonise its energy system and meet national and EU renewable targets.

Detailed Response

Comments on Section 4.2.2.2. Reactive Power Capability at Maximum Capacity: U-Q/PMax Profiles & Section 4.2.2.2.1 Article 18.2.b(i); SPGM: Parameters required for U-Q/Pax Profiles

The examples provided at the ESB Networks/EirGrid workshop highlight the potential impact of the network code changes. Under the existing ESB Network connection planning standards a 33MW generator can connect with up to 27km of 38kV cable before the voltage rise limit is exceeded. This would reduce to only 4km with the 1.1pu voltage limits proposed in the network codes. It appears there will likely be similar reductions for MV connections.

The practical impact of the proposed new voltage limits is that new generators connecting under the ECP-1 process could have more expensive grid connections. As most windfarm connections require dedicated shallow connections more than 5-10km, the change will likely impact on a high percentage of distribution applicants. Impacts could include requiring the generator to connect at a higher voltage, the requirements for larger conductors, greater levels of network reinforcement or the projects having to reduce the MEC to achieve a viable connection method. As the new RES support scheme will be auction based, these increased connection costs will result directly in higher costs for the Irish consumer.

There could also be a substantial impact on generators wanting to modify their connection agreements in the future. Windfarms will require a new connection agreement to repower the project or to extend the project with further wind or alternative technologies such as batteries or solar. If the new connection agreements are based on the new network codes voltage requirements, then many projects may receive connection offers with substantially reduced MECs. This would reduce the capacity of renewables connected to the system and goes against the recent future modelling of the system by DCCAE in the RESS consultation process.

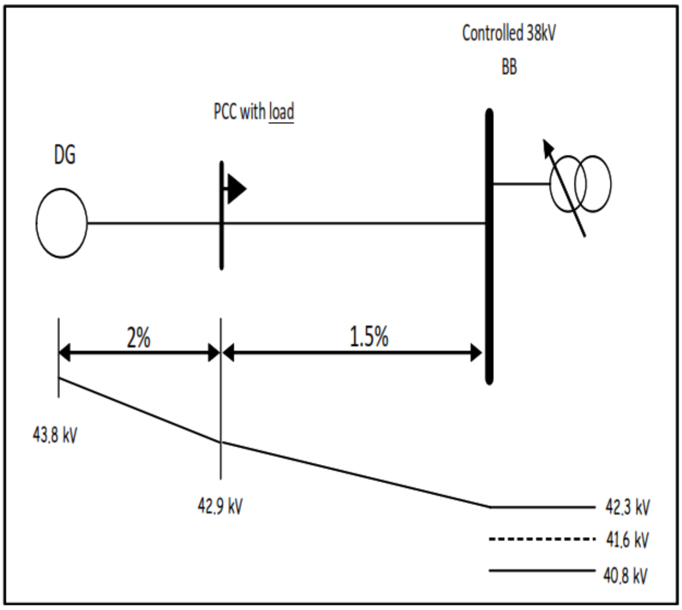
The IWEA are very surprised that the EU network codes for generators could have such a major impact on ESB Networks' planning standard for generator connections. We had understood that the new network codes would harmonise grid code requirements for generators only, i.e. 'behind the meter' requirements. The fact that the new network codes could make many existing and new distribution connections unviable is extremely concerning to the IWEA and its members.

The 1.1pu voltage limit does not appear to have any negative implications in other jurisdictions, for example Northern Ireland. The reasons that the 1.1pu limit will have such a major impact in Ireland does not appear to be just about how ESB Networks plan generator connections. All DNOs have to allow for voltage rise for the connection of embedded generation. However, in other jurisdictions there is sufficient headroom for voltage rise from generators without exceeding the 1.1pu voltage limit. It appears that in Ireland the issue is mainly due to the wide voltage range that ESB Networks allow for demand connections. This wide voltage range allows for the connection of greater demand capacity on Ireland's relatively long distribution network.

As Table 6a from the distribution code below shows, for the nominal voltage of 38kV, an operational voltage range of 35.6kV to 43.8kV is allowed. This is -6% and +15% from the nominal voltage. The sample 38kV connection diagram below also shows that ESB Networks usually have a voltage range of 40.8kV to 42.3kV at 38kV busbars, which is substantially higher than the nominal 38kV voltage. As mentioned above, the use of the wide voltage range, particularly at the upper end, is to allow for connection of demand on long distribution connections. It should be noted that 42.3kV, the higher end of the busbar voltage, is already above the 1.1pu. There appears to be similar issues for the medium voltages of 10kV and 20kV.

TABLE 6A			
Description	Nominal Voltage	Normal Operating Range [kV][5]	
		Lower bound	Upper bound
MV	10kV	9.6	11.3
MV	20kV	19.3	22.5
HV	38kV	35.6	43.8
110kV	110kV	99	123

Table 6a from Distribution Code



Sample 38kV Connection Method

The IWEA strongly oppose the implementation of the new 1.1pu voltage limit at 38kV and MV. The IWEA request that at 38kV the current limit of 1.15pu or 43.8kV is maintained and at MV the 1.125pu or 22.5kV is maintained. IWEA believes that there may be some technical solutions of how to address the impact of the change to voltage limits in the network codes. For example, changing the nominal voltage from 38kV to 40kV. However, considering the potential interactions of a technical solution to the overall operation and design of the distribution system we believe that ESB Networks are best placed to review and advise on technical solutions.

In the absence of a viable technical solution there should also be the opportunity for non-technical solutions. In the medium-term, changes should be made to the EU network code legislation to take into account the design and topology of the Irish electricity distribution system. There does appear to be jurisdiction exemptions made within the proposed network codes to take account of existing local circumstances. However, it would not be acceptable that the proposed network codes are adopted in the short term. This would result in multiple projects in ECP-1 receiving unviable connection offers. It may also result in some currently contracted generators having signed connection agreements with non-compliant connection methods. IWEA requests that ESB Networks clarify whether the intention of the Network Codes is to standardise generator capability only and not network planning standards.

If the network codes are intended to standardise network planning standards, then we ask that ESB Networks apply for a derogation from these sections of the network codes until either an enduring technical solution or a change to the network codes is achieved.

In summary, the IWEA are extremely concerned at the proposed new voltage limits in the network codes for 38kV and MV connections. If these changes are implemented, it will have a hugely negative impact on the capacity of renewables connected to the Irish system and the cost of electricity for the Irish consumer. Due to the design and topology of the Irish electricity distribution system, there does appear to be special circumstances that justify the existing voltage limits for network planning being maintained. The IWEA requests that in the short term there should be derogations requested from these sections of the network codes and in the medium term an enduring solution implemented.

The Irish Wind Farmers Association,
Unit F06 Kilkenny Research & Innovation Centre,
Burrell Hall,
St. Kieran's College,
Kilkenny,
Ireland
Tel: 056 7790856
Email: info@mnag.ie
Web: www.mnag.ie

Submission to
EirGrid and ESB Networks

on

EirGrid and ESB Networks' proposal for the general application of technical requirements in accordance with Articles 13-28 of the Commission Regulation (EU) 2016/631 establishing a network code on requirements for grid connection of generators (RfG)

Non-confidential

Response prepared by MullanGrid Consulting for IWFA

by email to: gridcode@eirgrid.com

1. Introduction

The IWFA welcomes the opportunity to respond to EirGrid and ESB Networks' consultation on the implementation of EU network codes for generators. Having reviewed the consultation document, the IWFA is mainly focusing its response on the aspects of the proposed network codes that could have a negative impact on the connection and operation of renewable generation.

2. Comments on Section 4.2.2.2. Reactive Power Capability at Maximum Capacity: U-Q/PMax Profiles & Section 4.2.2.2.1 Article 18.2.b(i); SPGM: Parameters required for U-Q/Pax Profiles

The comments are specifically on the 1.1 pu limit (Umax) for 38kV and MV connections.

The examples provided at the ESB Networks/EirGrid workshop highlight the potential impact of the network code changes. Under the existing ESB Network connection planning standards a 33MW generator can connect with up to 27km of 38kV cable before the voltage rise limit is exceeded. This would reduce to only 4km with the 1.1 pu voltage limits proposed in the network codes. It appears there will likely be similar reductions for MV connections.

The practical impact of the proposed new voltage limits is that new generators connecting under the ECP-1 process could have more expensive grid connections. As most windfarm connections require dedicated shallow connections more than 5-10km, the change will likely impact on a high percentage of distribution applicants. Impacts could include requiring the generator to connect at a higher voltage, the requirements for larger conductors, greater levels of network reinforcement or the projects having to reduce the MEC to achieve a viable connection method. As the new RES support scheme will be auction based, these increased connection costs will result directly in higher costs for the Irish consumer.

There could also be a substantial impact on generators wanting to modify their connection agreements in the future. Windfarms will require a new connection agreement to repower the project or to extend the project with further wind or alternative technologies such as batteries or solar. If the new connection agreements are based on the new network codes voltage requirements, then many projects may receive connection offers with substantially reduced MECs. This would reduce the capacity of renewables connected to the system. This will negatively impact on Ireland's ability to meet EU renewable targets and will have other potential consequences such as higher electricity costs for consumers and potential EU fines. From a high-level review of all distribution connected windfarms it is estimated that it could negatively impact on more than 40% of the connected capacity.

The IWFA are very surprised that the EU network codes for generators could have such a major impact on ESB Networks' planning standard for generator connections. We had understood that the new network codes would harmonise grid code requirements for generators, i.e. 'behind the meter' requirements. The fact that the new network codes could make many existing and new distribution connections unviable is extremely concerning to the IWFA and its members.

The 1.1pu voltage limit does not appear to have any negative implications in other jurisdictions, for example Northern Ireland. The reasons that the 1.1pu limit will have such a major impact in Ireland does not appear to be just about how ESB Networks plan generator connections. All DNOs have to allow for voltage rise for the connection of embedded generation. However, in other jurisdictions there is sufficient headroom for voltage rise from generators without exceeding the 1.1pu voltage limit. It appears that in Ireland the issue is mainly due to the wide voltage range that ESB Networks allow for demand connections. This wide voltage range allows for the connection of greater demand capacity on Ireland's relatively long distribution network.

As Table 6a below shows for the nominal voltage of 38kV, a voltage range of 35.6kV to 43.8kV is allowed for generator connections. This is -6% and +15% from the nominal voltage. The sample 38kV connection diagram below also shows that ESB Networks usually have a voltage range of 40.8kV to 42.3kV at 38kV busbars, which is substantially higher than the nominal 38kV voltage. As mentioned above, the use of the wide voltage range, particularly at the upper end, is to allow for connection of demand on long distribution connections. It should be noted that 42.3kV, the higher end of the busbar voltage, is already above the 1.1pu. There appears to be similar issues for the medium voltages of 10kV and 20kV.

TABLE 6A

Description	Nominal Voltage	Normal Operating Range [kV][5]	
		Lower bound	Upper bound
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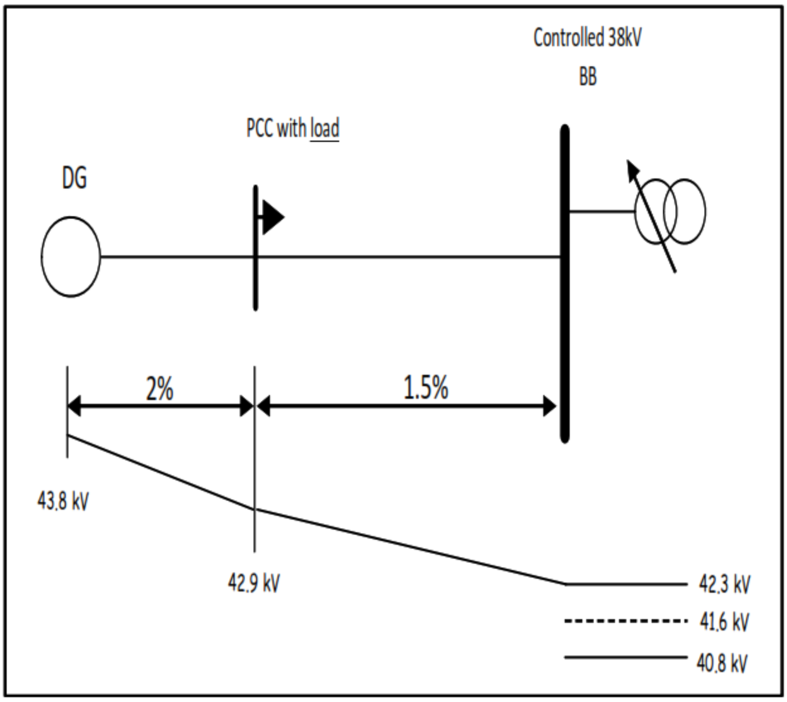
HV	38kV	35.6	43.8
110kV	110kV	99	123

Table 6a from Distribution Code



Sample 38kV Connection Method

The IWFA strongly oppose the implementation of the new 1.1 pu voltage limit at 38kV and MV. The IWFA request that at 38kV the current limit of 1.15pu or 43.8kV is maintained and at MV the 1.125pu or 22.5kV is maintained. IWFA believes that there may be some technical solutions to address the impact of the change to voltage limits in the network codes. For example, changing the nominal voltage from 38kV to 40kV. However, considering the potential interactions of a technical solution with the overall operation and design of the distribution system we believe that ESB Networks are best placed to review and advise on technical solutions.

In the absence of a viable technical solution there should also be the opportunity for non-technical solutions. In the medium-term, changes should be made to the EU network code legislation to take into account the design and topology of the Irish electricity distribution system. There do appear to be jurisdiction exemptions made within the proposed network codes to take account of existing local circumstances. However, it would not be acceptable that the proposed network codes are adopted in the short term. This would result in multiple projects in ECP-1 receiving unviable connection offers. IWFA requests that ESB Networks apply for a derogation from these sections of the network codes until either an enduring technical solution or a change to the network codes is achieved.

In summary, the IWFA are extremely concerned at the proposed new voltage limits in the network codes for 38kV and MV connections. If these changes are implemented, it will have a hugely negative impact on the capacity of renewables connected to the Irish system and the cost of electricity for the Irish consumer. Due to the design and topology of the Irish electricity distribution system, there do appear to be special circumstances that justify the existing voltage limits being maintained. The IWFA requests that:

1. in the short term, derogations should be requested from these sections of the network codes, and,
2. in the medium term, an enduring solution should be devised and implemented.

RfG Art 13 (4) and (5): power vs frequency: Manufacturers' recommendations

Brussels

4 October 2017

Power vs. frequency: RfG wording

Art 13:

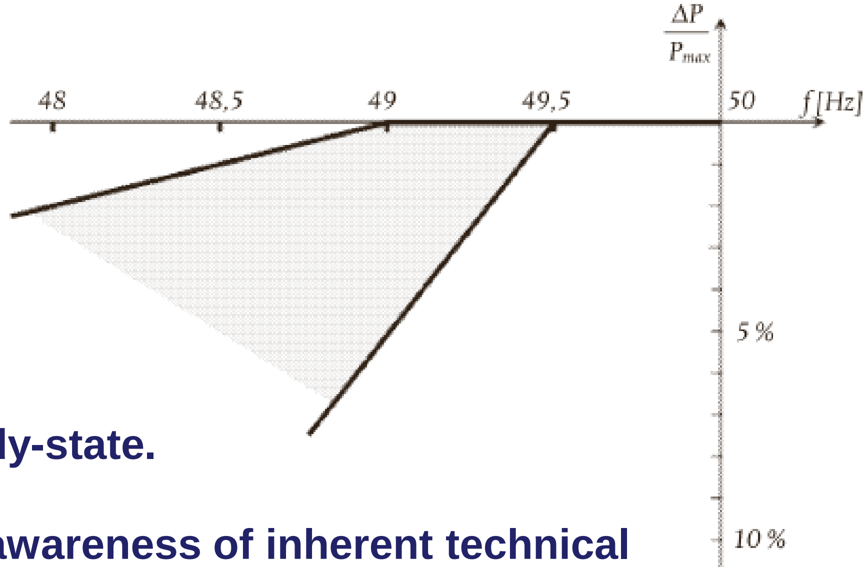
(4).The relevant TSO shall specify admissible active power reduction from maximum output with falling frequency in its control area as a rate of reduction falling within the boundaries, illustrated by the full lines in Figure 2:

…

(5).The admissible active power reduction from maximum output shall:

a) clearly specify the ambient conditions applicable;

b) take account of the technical capabilities of power-generating modules



No requirement to dynamic behaviour.

The requirement can be interpreted as steady-state.

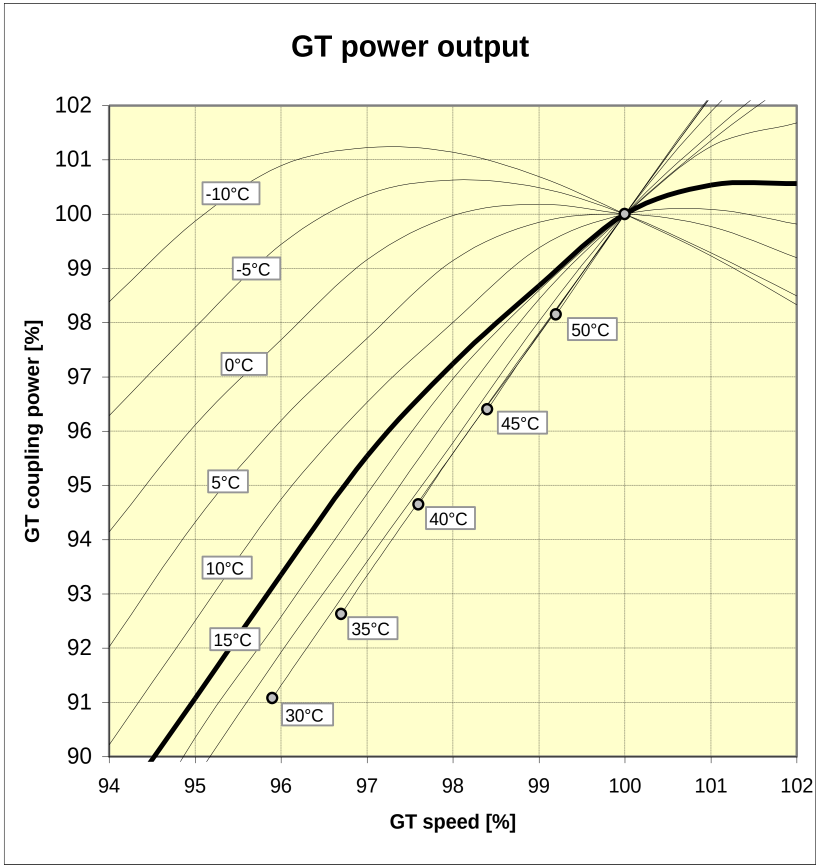
Art 13 (5) has been introduced to RfG after awareness of inherent technical constraints of some relevant technologies: equal to or prevailing Art 13 (4)!

Power vs. frequency

The facts:

- Gas Turbines output is influenced by different external factors. Depending on ambient conditions, power drop exceeds allowed values in Art 13 figure 2.
- Principle steady-state behaviour is shown in att. figure (values are only indicative!)
- Dynamic behaviour is worse since compensating power control loops need time to react to frequency drop (if reserve is available)

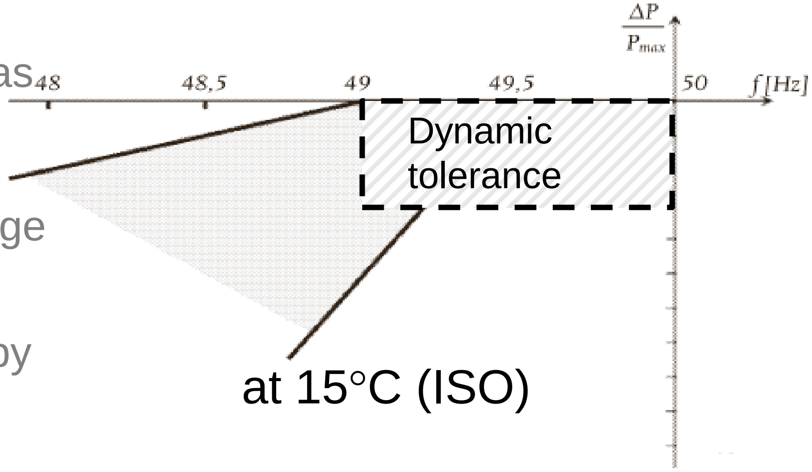
Technical and ambiental limitations to be considered in requirement !



Power vs. frequency: Recommendations

Recommendations for IGD and national implementation

- Apply lower end of RfG range in Art 13 fig 2 for steady-state
- Allow further relaxation according to Art. 13 (5) (a) in case of evident technical constraints (without derogation process); consideration of known behaviour of plants at maximum output is better for system stability than increased risk of trip!
- Allow further relaxation in case short-term dynamic requirement (timeframe tbd) is deemed to be necessary and allowed by RfG
- Apply ISO 2314 reference temperature (15°C) as the relevant ambient condition to both steady-state and dynamic requirement (if applicable): standard condition for turbine design and average temperature in many countries in the EU
- Behaviour at other conditions can be provided by manufacturers on a project specific basis for consideration in system studies



Issue #WP101: Technical Information from Cummins Generator Technologies

Fault Ride Through Effects on Alternators Connected to the Grid

White Paper

Sridhar Narayanan
Gary Berridge
Andreas Biebighaeuser
Neil L. Brown

Abstract

A significant shift in environmental policies and energy deregulation in the last decade has led to the growth of renewable energy sources. Led by the development of wind farms throughout Europe, changes to 'Grid Codes' have been implemented requiring embedded generation schemes to stay connected during the presence of system faults (Fault Ride Through requirements). This is contrary to the traditional approach, whereby the power plants were not required to stay connected. Changes to the grid codes also include wider operating limits under steady state conditions (Voltage, power factor limits etc). These changes impose significant stresses on the genset and associated components such as the alternator. Genset manufacturers are posed with the problem of not just dealing with these new challenging operating conditions, but also variation in the grid code requirements across various network operators and countries.

This paper discusses the experience of Cummins Generator Technologies as an alternator manufacturer in addressing these challenges. For the purpose of this paper the authors perform a case study on the impact of the German grid code on the alternator design and performance and then attempt to provide a generalised view of the impact of grid codes on alternator sizing / selection.

I. Introduction

Traditionally, industrial countries have generated most of their electricity in large centralised facilities, such as fossil fuel (coal, gas), nuclear, large solar power plants or hydropower plants. Although these plants have excellent economies of scale, they usually transmit electricity over long distances and negatively affect the environment. More recently, a surge in the concerns over climate change has led to a modification of energy policies so as to facilitate energy to be produced and consumed in an eco-friendly manner. These changes have brought about an increase in what is now called distributed generation. Distributed generation also seems to fit in well with being able to accommodate a grid architecture with renewables. While distributed generation plants have low maintenance, low pollution and high efficiencies, they have a tendency to make the grid unstable. It is for this reason that a number of grid operators around the world have begun enforcing performance expectations on generating sets. These expectations – called 'Grid Codes' exist primarily to ensure stable & continuous operation of power systems. The most challenging aspect of grid codes is the Fault Ride Through / Low Voltage Ride Through requirements. Table 1 and Figure 1 summarise the key requirements of the German grid operator – E.ON [1] and will be the focus of this paper. Low Voltage Ride Through refers to an event when the voltage at the point of common coupling drops below a critical value.

Earlier, power plants could disconnect from the grid in the event of a LVRT; but grid codes require that power plants stay connected to the grid for period of time during a LVRT event – without going unstable. The situation is worsened because of the static requirements that grid codes demand.

Quantity E	xpectation
Voltage variation	+/- 10%
Frequency deviation	+/- 2%
Power Factor Range 0	.95 lead to 0.95 lag
Power delivered at above conditions	100% engine load
Fault ride through time	150 ms
PCC voltage during fault ride through	30% nominal

Table 1: German Grid Code

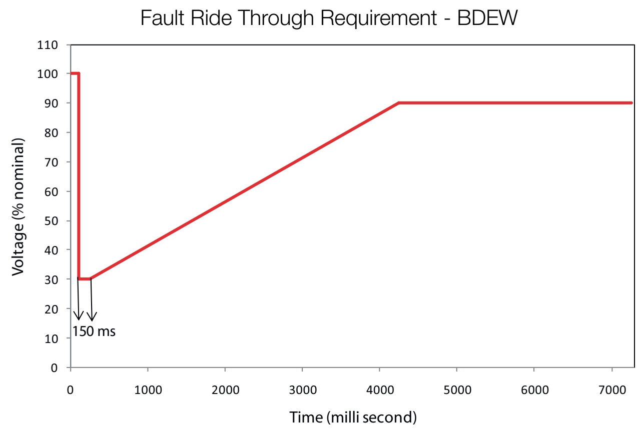


Figure 1: Low Voltage Ride Through – Germany

These include continuously operating the power plant, and hence the generating set at an underexcited power factor, while providing rated load at lower than nominal point of common coupling voltage. In this paper, the authors explain the effect of a LVRT on an engine driven alternator connected to the grid and hence explain the challenges that Cummins Generator Technologies as an alternator manufacturer has faced while designing alternators for such applications.

II. Fault Ride Through - Description

Figure 2 represents an engine driven genset directly connected to the grid without a transformer.
The performance of the genset under steady state grid code conditions has been discussed in detail by S. Narayanan et al [2] and so the focus of this paper will only be on the performance of the genset during a fault ride through Earlier, power plants could disconnect from the grid in the event of a LVRT; but grid codes require that power plants stay connected to the grid for period of time during a LVRT event – without going unstable. The situation is worsened because of the static requirements that grid codes demand.

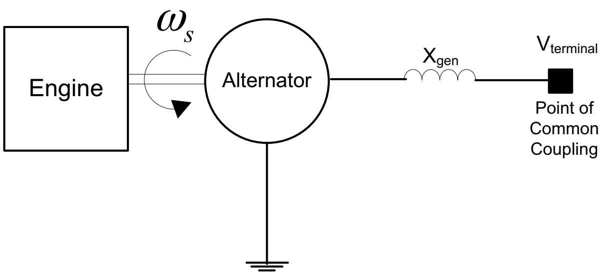


Figure 2: Engine Driven Genset

The E.ON code requires that a genset be capable of staying connected to the grid without losing stability for up to 150 ms in the event of a fault ride through and then smoothly transition back into its pre-fault operating point once the grid returns. To be able to understand the challenges posed by a fault ride through condition to an alternator, a basic understanding of the fault ride through mechanism is needed. To illustrate the basic mechanism of fault ride through, the authors describe the fault ride through as two independent events – (A) a genset going into a fault and riding through and (B) the fault clearing and the grid coming back online.

A. Genset Going into a Fault and Riding Through

The behavior of a genset riding through a fault is a transient stability problem. Assume that before the fault occurs, the genset is operating at some steady-state condition. The engine is delivering some torque Tmech to the alternator that is supplying an electromagnetic torque Tem to some electrical load. For stable operation of the genset, the mechanical torque must equal the electromagnetic torque. During a fault, the alternator is no longer supplying real power and this causes all the stored energy in the engine to accelerate the rotor and thereby increasing the risk of a pole-slip. It is during this phase that pole-slip must be avoided according to grid codes.

B. Fault Clearing and Grid Coming Back Online

The alternator that has accelerated during the fault ride through now gets connected to the grid that returns to pre-fault levels. This would mean that there is a likelihood of an out of phase synchronisation event. The difference in the alternator and grid voltages are determined by how much the alternator has accelerated by which is again a function of the alternator design and the fault clearing time. The extent of out of phase synchronisation needs to be minimised to reduce damage to the genset and to return to pre-fault operating points quickly and within the time frame recommended in the grid codes.

III. Fault Ride Through Effects on an Alternator

Section 2 described the phenomena of fault ride through and the events that the genset is exposed to during a fault ride through. In this section, the authors explain the effects of fault ride through on an alternator. The performance of alternator pre-fault ride through, during fault ride through and post fault ride through will be addressed separately so as to fully describe the impact on the alternator. It is assumed that the genset is operating at a worst case steady state operating condition as dictated by the E.ON code – i.e. 0.95 leading power-factor while supplying 100% load at 10% lower than nominal voltage [2].

A. Pre-fault Ride Through

Steady-state power delivered (Pe) delivered by the genset is given by (1) [3].

(1):

$$Pe = \frac{E_q V_T}{X_d} \sin \delta + \frac{V_T^2}{2} \frac{X_d - X_q}{X_q X_d} \sin 2\delta$$

The in (1) is the steady-state load angle of the alternator and defines the static & dynamic stability limits of the alternator according to (1) and (2) [3].

(2):

$$P_m - P_e = \frac{2HS_n}{\omega_s} \frac{d^2\delta}{dt^2} + D\frac{d\delta}{dt}$$

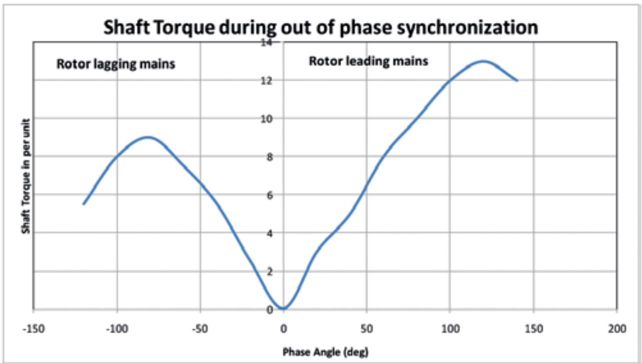
For a loading condition defined in the preceding part of this section, the steady-state load angle tends to be high – due to the leading power factor operation and lower point of common coupling voltage condition. Under this operation, the stator is operating at anelevated temperature (thermally stressed); there is reduced electromagnetic coupling between the rotor and stator due to the under-excited condition.

B. Fault Ride Through

The terminal voltage (Vterminal from Figure 2) of the genset drops to 30% of its nominal value. This reduces the real power delivered by the alternator by 70%. As the mechanical time constants are much bigger comparedto the electrical time constants, the engine is supplying 100% of the genset kilowatts. The excess kinetic energy stored in the shaft of the genset accelerates the rotor. The amount ofacceleration is determined by (2). It is during this operating regime that the grid codes require the genset does not run away into a poleslip scenario but remain stable for a smooth connection back to the grid. Acceleration of the rotor induces high currents in the dampers; longer the duration of the fault ride through, higher the thermal stresses on the damper bars. A fault ride through also induces huge short-circuit like current transients on the stator windings. These currents lead to large electromagnetic forces on the windings thereby stressing them and impacting insulation life.

C. Fault Clears, Grid Returns

The genset that has accelerated during the fault is now connected to the grid after the fault hasbeen cleared. The voltage of the alternator and the grid do not match and this leads to an out of phase synchronisation. Energy is exchanged between the alternator and the grid as one tries to pull the other back into synchronism. An outof phase synchronization involves large currenttransients on the stator, large torque transientson the shaft, and heating of damper bars. Figure 3 shows the plot of shaft torques (in per unit) for synchronisation at different phase angles on a test machine. Figure 4 shows pictures of the shaft (around the key area) of the same test machine damaged due to the large torque transients that occur during an out of phase synchronisation event. The phase angle at which the out of phase synchronisation happens depends on how far the rotor has accelerated from its initial position and how long the fault lasted.



The shaft torque in Figure 3 refers to the torque calculated using (3)

$$T_{shaft} = T_{em} \frac{J_{drive}}{J_{alternator} + J_{drive}}$$

Figure 3: Shaft Torque during out of Phase Synchronisation

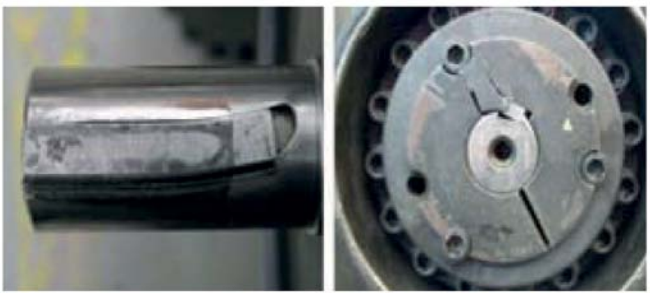


Figure 4: Damaged Key Due to Torque Transients

IV. Design of Alternator - Fault Ride Through Applications

Design of the genset for a grid code compliance / fault ride through application involves design of alternator and the engine individually and as a system for optimum performance. This section describes the lessons learnt by Cummins Generator Technologies while analysing alternator designs for grid code compliance / fault ride through applications. Design for a grid code compliance application involves:

A. Design for compliance

B. Design for robustness

A. Design for Compliance

Grid codes impose performance expectations during steady-state conditions and during a fault ride through.

(a) (1) suggests that the best way to maintain static stability is to keep the steady state load angle low by tuning the reactances (Xd, Xq). Xd should be lowered as necessary to stay well within static stability limit [2].

(b) Fault ride through requirements state that the genset must not pole slip up to the maximum fault clearing time stated by the grid codes – 150 ms for Germany. Pole slip is caused by excessive acceleration and a high steady state load angle of the alternator; pole slip can therefore be avoided by designing an alternator with a low Xd to ensure a low enough steady state load angle, a high inertia constant (rotor inertia / machine kVA) to reduce acceleration during transients and the sub-transient reactances (X"d, X"q) and hence sub-transient saliency to tune the electrical time constants.

These changes involves significant modifications to the electrical machine design; for example, an optimal tuning of the reactance involves either a derate or designing the machine with a bigger air gap. Any change to the machine design (like air gap increase) will affect the overall performance of the machine (say efficiency) and so care needs to be taken to ensure overall performance does not take a hit. There is also a limit on how much inertia can be added to any alternator.

B. Design for Robustness

To operate a genset in a grid code compliant application means to expose the alternator to huge forces and stresses – both thermomechanically and electrically. The various causes of stresses in the alternator are:

(a) Thermal stresses on the stator windings– caused by over-current conditions (reduced voltage under steady-state operation): danger to the lifetime of the insulation – alternator needs to be de-rated

(b) Mechanical stresses – the huge current transients induce large electromagnetic forces on the stator windings which cause displacement / vibration of the windings.

Figure 5 captures the 3 components of the electromagnetic force in an electrical machine and what causes them - Current transients are a function of the sub-transient and transient reactances of the alternator and hence by may be modified to reduce the fault currents and hence winding forces to acceptable levels.

Additionally, mechanical reinforcement of the windings can be ensured by designing a suitable bracing and picking the right impregnation for the windings to minimise vibrations / winding displacement.

(c) Thermal stresses on the damper bars – due to the huge currents induced during long fault ride through scenarios and the simultaneous electromagnetic forces that act on them due to large current transients

(d) Mechanical stresses on the shaft – out of phase synchronisation can exert immense forces on the shaft and without the right ratio of alternator to engine inertias, these torques can cause significant damage to the engine.

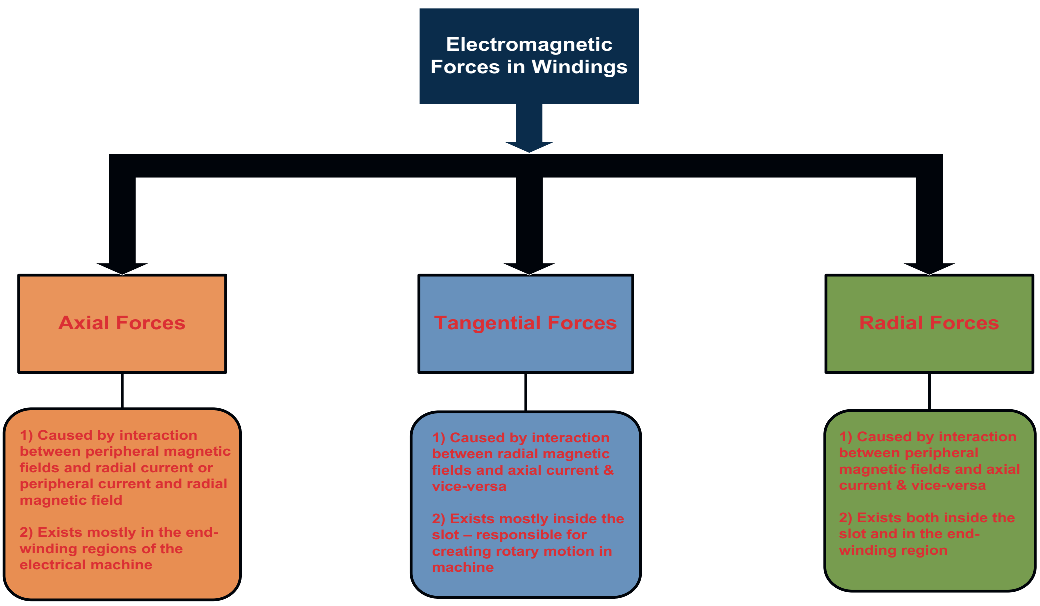


Figure 5: Electromagnetic Force Components in Alternator Windings

Conclusion

Figure 6 [4] compares the magnitudes of various forces on generator windings and reinforces the need to understand these forces while designing a robust alternator that is also grid code compliant. S.Narayanan et al [2] have shown that for an alternator to satisfy the steady state requirements of the German grid code, the short-circuit ratio of the alternator needs to be at least 0.45 which puts the value of Xd (main d-axis reactance) at around 2.28 pu. If the same machine had to be then optimized to satisfy fault ride through requirements, a further reduction in Xd is required followed by an increase in the inertia and sub-transient reactances of the machine to ensure robustness and grid code compliance. A high sub-transient reactance to reduce forces on windings also means reduced fault current levels and low starting torques. Modifying winding stiffness to minimize displacements involves re-configuring the windings to eliminate failure modes, modifying bracing and hence potentially modifying alternator packaging. The paper only includes alternator design with the German grid code as an example. There exist however, grid codes in other countries, some of which are more stringent than the German grid codes; this would mean a different alternator sizes for the grids in different countries. Unreasonable requirements such as voltage being depressed for a prolonged time after fault clearing, or overly long fault clearance times, in combination with abnormal operation conditions such as operation on overload or under excitation, might lead to fault ride through conditions that may not be met by commercially viable equipment. There is a need, therefore, for sound engineering judgment as to which conditions should apply any given network. Designing for absolute extremes or unlikely operation conditions is neither economical nor practical. Transmission and distribution operators should therefore set reasonable rules for fault ride through capabilities. An alternator that is meant to be used in a standby generating set should by nature be compact – hence smaller air gap (high power density) and reduced mass (for easy transportation). The introduction of grid code compliance and the proliferation of distributed generation would mean that these alternators that were traditionally used only in standby gensets will now have to become bigger and more robust to be allowed to connect to the grids.

Acknowledgements

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Cummins Generator Technologies Ltd
Barnack Road, Stamford
Lincolnshire, PE9 2NB, UK

Tel: +44 (0) 1780 484000
Fax: +44 (0) 1780 484100
email: info@cumminsgeneratortechnologies.com

www.cumminsgeneratortechnologies.com

WP_LVRT_S_EN_GS_02

V.ret Clarification …GC0048T… Synchronous Generators…AMPS Position

Overview.

The minimum value for an FRT related retained voltage (U.ret) has been identified as an issue for certain kinds of type B synchronous power generating units, specifically when the prime mover is a reciprocating internal combustion (RIC) engine. Accepting that such units are unlikely to be greater than 5MW, therefore likely to be a low population within the total network scheme, working group GC0048T has asked AMPS to provide a technical explanation to support their request for such synchronous generators to have U.ret set at 30% for a duration of <150ms (FRT event). It may be that type B synchronous generators with RIC prime movers are considered as a special case.

Technical Comment.

1. Present position;

The performance capability requirements set by RfG has introduced major technical changes to a typical synchronous power generating equipment package which until now has been applied to Grid Connect duties. In summary these RfG changes require the incorporation of considerably more materials to achieve enhanced operational functional capability, thus incurring additional cost in the in the following areas;

- Alternator active materials; copper and iron related to electro-magnetic systems.
- Increased spinning inertia of engine + alternator assembly (H).
- Robustness of alternator winding construction.
- Robustness of engine/alternator mechanical driveline and equipment foundation structure.
- Integrated and enhanced control system functions for alternator and engine.
- Boosted generator operational control schemes, protection, metering and communications.
- Reactive VAr dynamic control.
- Exhaustive compliance testing and related approval process.

The above changes have <u>increased the price of an RfG unit by some 40%</u> above that of a typical pre 2015 manufactured G59 related compliant power generation equipment package.

Regarding the capability of the presently developed RfG units, AMPS members have provided stakeholder feedback that such RfG units subjected to 'unofficial' testing regimes have the capability to be RfG compliant with the proviso that the U.ret condition is 30% for a duration of <150ms.

There now follows a technical explanation to support why this position has been taken. It is hoped the following will lead to an understanding of the significant performance differences between synchronous generators powered by reciprocating internal combustion (RIC) engines and solid state power electronic based generators. The ideal solution with regard to the adoption of a value for U.ret., is for a special case to be introduced for RIC powered synchronous generation .

Technical Explanation

2. Alternator

A synchronous power generating module must be able to 'feel' the network's ac voltage waveform being applied to the alternator's stator windings as this is the only way the alternator's rotor can detect the stator assembly's related electro-magnetic flux to which the rotor must remain aligned and so hold synchronism with that network's three phase ac voltage waveform.
An alternator's rotor does not hold a single point of alignment with the stator winding assembly. It does in fact adopt an arc of angular-bandwidth of relative positional alignment to the stator winding flux; this arc being referred to as the rotor load angle. An operational rotor load angle is directly related to the alternators terminal voltage and electrical output; P.S & Q. The rotor pole position will be in the same relative load angle alignment position for each of the three phases winding groups; presuming symmetrical load conditions. Under asymmetric load conditions the rotor load angle will have an oscillatory dynamic behaviour, with the rotor damper cage working hard to dampen the degree of load angle changes.
Maintaining an ideal rotor load angle becomes compromised if the alternator loses direct control over its terminal voltage level. For example when operating in synchronism with a network supply where the voltage level will not be constant as even during normal operating conditions the network voltage operates over a wide voltage regulation band which may be +/-10%, which at each extreme forces the rotor load angle to notably change.
During network instabilities such as FRT(LVRT), it is known there will be rapid and severe reductions of the voltage level applied to the alternator terminals which in turn will seriously compromise the alternator rotor's ability to maintain a practical-working load angle and so stay in synchronism.

FRT (LVRT) places demands on the alternator which requires a tight control to be in place of the operating arc span of the rotor load angle. This means the alternator needs to be designed to have increased inherent electro-magnetic stiffness. The rotor will then be held more 'stiffly' aligned to, and so more positively locked in synchronism with, the stator related flux driven by the connected network voltage ac waveform.
This 'stiffening' is achieved by using an alternator with an electro-magnetic design (EMD) which drives for a low value of Synchronous Reactance (Xd). It is generally accepted that an RfG compliant alternator will need to have Xd <2.0pu.when correlated to the alternators defined rated output of P, S & Q at the nominal value of the identified operating voltage at fundamental frequency. For reference the reciprocal of Xd = Short Circuit Ratio (SCR)
so an Xd of 2.0 = SCR of 0.5

Any reduction in the network voltage level will result in that elements reduced level of generated air-gap flux which means the rotor is forced to operate in an electro-magnetic environment where there is a reduced level of electro-magnetic stiffness and so synchronising alignment attraction.

A critical situation being reached should the network voltage become so low that only a weak level of electro-magnetic attraction is present, which would result in a situation where the rotor's load angle increases to a point where electro-magnetic attraction becomes even weaker and a loss-of-synchronisation/pole-slip, occurs.

Recapping the above alternator evaluation.
It has been described how the rotor load angle varies with the level of stator winding output P, S & Q. It therefore follows that under allowable bandwidth variations of network voltage which is typically; V.rated +/- 10% limits. That once a steady state condition of network voltage prevails the generating modules control functions will adjust levels of P, S & Q accordingly and correspondingly the rotor load angle will change. But the change will be minimal if the alternator has an EMD where at rated output for V.nom, Xd <2.0pu and so SCR >0.5

Now follows an outline of the critical situation for an RIC powered synchronous generating module.

When considering FRT (LVRT) events the associated prevailing conditions are dynamic in terms of both voltage level and time period for the indicated fault clearance period and the individual U. against t. recovery conditions.
The most severe condition is associated with the initial drop in network voltage to that of the retained voltage (U.ret.) and the associated time period for U.ret as the network protection system secures the fault.
RfG advises that P should be reduced and controlled proportionally to V (U).
However, a prime mover, of the RIC engine type, is unable to reduce the level of mechanical power being applied to the alternator at the same rate that the network has rapidly reduced the voltage being applied to the alternator stator winding. For an expanded explanation of why an RIC engine has a problem to rapidly reduce power: see following para 4.

The net result is that the alternator is suddenly operating with a very low level of electro-magnetic stiffness flux and so attraction force detectable by the rotor. Consequently the rotor load angle will increase under the effect of the following two mechanisms;

A] The reduced voltage has caused the alternators value of Xd to increase by a factor of several times its ideal value of 2.0pu. and very low value of SCR.

B] The prime mover mechanical shaft power is still at the pre-FRT event level, yet the alternator capability to maintain electrical output power by increasing the output current to maintain P about the much momentarily prevailing U.ret is not possible. See following para 3 for more information.

C] At this point the Inertia Constant (H) needs to be introduced. For if the synchronous generating module has sufficient H, and the time period t.clear is but a short period. Then H will provide the necessary stabilising effect to hold the rotor's angular position within the acceptable arc of rotor load angle. For a more detailed explanation see the following para 5.

3. Control Systems;

Once in synchronism with the network the generating module control systems are given new roles. The alternators excitation system is changed from voltage control to power factor (pf) control. The engines speed governor becomes the generators output power controller.

Accepting the network will frequently undergo transient<momentary changes of voltage (and quite rapid slew-rate changes of frequency) the now power factor and power control functions will themselves swiftly asses a detected change and move to correct and align to a new steady state voltage level. But these functions have a degree of ‘slugging’ with their output commands, to ensure actual corrections are necessary and then to apply them over a relatively slow period of typically 2<5s in order to ensure they do not cause the synchronous generating module to promote unnecessary additional network instability.

RfG requires any change in network voltage to be recognised and requires the generating module to respond within clearly defined disciplines. With regard to FRT and the related change to network voltage level an RfG generator should change its delivered power level in proportion to the percentage change of the voltage, thus requiring the generator’s integrated controller to have the necessary software functions.

4. Prime Mover considerations;

Under a constant-power mode of operation and a stable network, the shaft power applied to the alternator will perfectly match the alternators rotor/stator air-gap power (torque) demands to enable the stator to deliver the set levels of P,S & Q to the network; whilst naturally taking into account alternator losses. Any gradual change of network voltage level will be recognised and corrected as indicated in 3 above.

However, any sudden step change in the network voltage level, for example a FRT event, will introduce real problems with just how rapidly the prime mover can reduce the level of the pre-FRT shaft-power it applies to the alternator, and so take control over the operating P and so indirectly, S & Q levels.

Achieving a rapid reduction of developed engine power becomes a key performance requirement not just for supporting the alternator to stay in synchronism during the period of securing the fault (140ms being the GB time).

It becomes imperative that as the voltage recovers over a time period the prime mover is able to deliver controlled levels of power proportional to that recovering voltage; under conditions where the voltage will likely have a dynamic rate of recovery.

Considering the most cost effective RIC engine driven generators will operate at 1500rpm (4pole alternator), where a period of 140ms equates to 3.5 shaft revolutions. The engines being a 4 stroke cycle principle means no individual engine-cylinder will have more than one fuel injection event during the 140ms period. How many cylinders will be incorporated within a typical type B, 2.5 MW RfG generating module needs to be considered and the likelihood is 16<20.

At this point the realisation of the practicalities of rapidly reducing RIC engine power becomes apparent when considering: the finite time taken to recognise an FRT event, then issue the command to reduce the quantity of injected fuel, and then actually achieve much reduced levels of combustion chamber developed power.

5. Inertia Constant (H)

A typical pre 2015 G59 compliant synchronous generating module would likely have an inertia constant of; ~ 0.8s.
The introduction of RfG requirements and required FRT(LVRT) performance initiated the need to reconsider the value of H against the role it needed to play with supporting the alternator rotors need to stay in synchronism under an FRT where the network voltage's level of electro-magnetic attraction was very weak and the RIC engine's level of applied shaft power was very high.

Decisions regarding just what level of H should be incorporated within a synchronous generating module, needed to take into account two situations.

I] The practicalities of where to put the necessary rotating mass
II] Excessive H introducing mechanical drive line stress along with rotor load angle instability during a severe slew-rate over short-time RoCoF event.

Eventually a compromise was found and the required value of H for an RfG compliant synchronous generating module is considered to be typically 1.3s

This value of H becomes critical with regard to the FRT related duration of the t.clear time period. **This is why the AMPS position regard t.clear is set at <150ms.**

6. Setting U.ret set at 30% .

During the early days of RfG's development it was generally thought that for embedded LV generators the local network system would have a retained voltage of some 40<50% based on inherent characteristics of local LV networks even when an FRT event occurred in relatively close >200kV transmission systems.
The National Grid (NG) shared Future Energy Scenario (FES) and related system planning strategy work has now changed several aspects of this initial understanding just how a future GB network will behave, even at LV levels, during an FRT event. The latest thinking being that it LV system U.ret will likely be 30<40% for the 140ms associated with securing the fault.
This revised understanding, thankfully shared by the NG planning group, has been considered by AMPS members and has led to reappraising the technical capability of generators intended for the RfG application. This review has focused on the alternators inherent saliency along with the need for revised control systems with more closely integrated alternator excitation and engine power control functions perhaps even with some form of 'event' predictability based on system operators real-time knowledge of sensed network behaviour.

To support the AMPS position of requesting that U.ret is set no lower than 30% for RIC engine driven synchronous generating modules the following examples of where this threshold level is being used now follow.

Item 1;

The below Figure 8 is taken from : CLC/FprTS 50xxx Jan2016

The developing 50549/ 1 & 2 are referenced within CLC/FprTS 50xxx

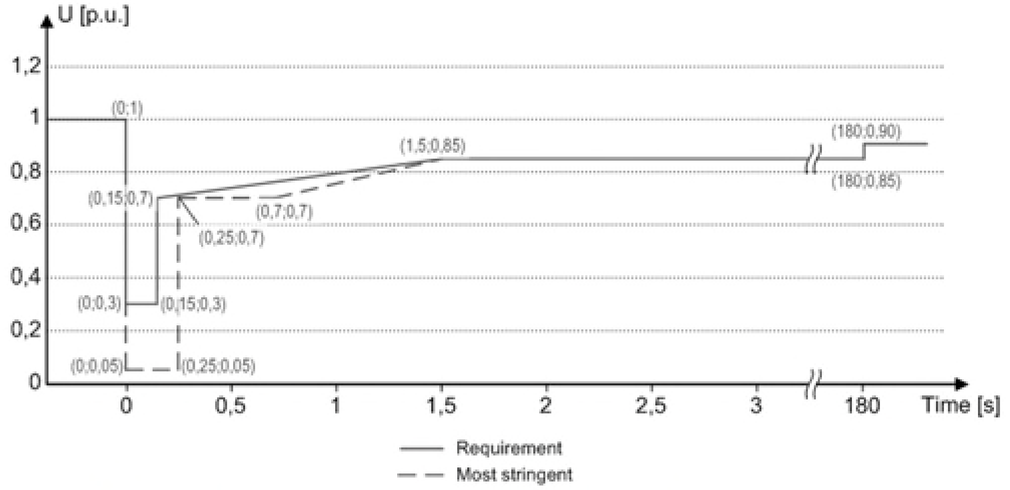


Figure 8 - Low voltage ride through capability for directly coupled generating technology

Item 2;
Attached as Annex 1
Cummins Generator Technology White Paper which describes Fault Ride Through effects on alternators connected to the grid.
Within the document the case is made for having U.ret set at 30% for alternators to be driven by RIC engines for synchronous generating modules.

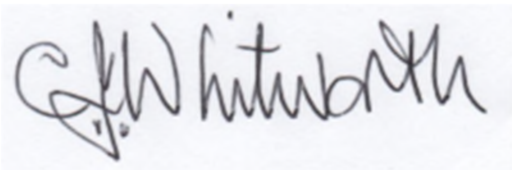
Item 3;
Attached as Annex 2
A technical explanation which considers a Synchronous Generator and Retained Voltage levels against the principle of a Power Angle Curve. This document outlines the challenges of maintaining synchronism when the network voltage reduces below a critical level where engine shaft power torque exceeds the generator's air-gap torque as a consequence of the reduced network voltage; the aftereffect being loss-of synchronism/pole-slip.

The AMPS Position:

It is hoped this technical explanation provides the necessary justification to support the AMPS position that RIC powered synchronous generating modules should not be required to comply with a U.ret below 30% for a t.clear duration period exceeding 150ms

AMPS members have provided feedback which supports the above outlined position.
It has not been possible to provide supporting test data as each participating AMPS member advised the need to protect their RfG intended product designs and specific performance capability. In the case of partnership developments between manufactures of engines, alternators, control systems and protection schemes these parties are bound by Non-Disclosure Agreements not to reveal any product incorporated 'special' features and most importantly share specific cost variations and proposed market prices.

Submitted on behalf of AMPS by:



Chris J Whitworth

AMPS Technical Specialist

AMPS member's stakeholder feedback related to the GC0048T proposal for U.ret change from 0.3pu down to 0.15pu.

1. AMPS members remain resolved that the U.ret related document*- which advises a 0.3pu U.ret for a duration <150ms - still represents their experienced view of what is realistically achievable without Loss of Synchronisation for a type B SPGM powered by an RIC engine where the total SPGM equipment will typically have an inertia in the region of 1.2s.
*(**05/04/2016. U.ret Clarification …GC0048T… Synchronous Generators…AMPS Position**).

2. Large companies manufacturing SPGMs have the ability to develop bespoke combinations of prime-movers and alternators jointly controlled by a single encompassing regulator to form a special SPGM able to meet a U.ret of 0.15pu, but the end product is complex and costly. The consequence is that small companies presently involved with SPGM OEM products will not have the necessary special equipment, technology and required development budgets. This will result in a loss of a competitive business base for type B SPGMs and therefore contrary to the ENTSOe objective of facilitating a competitive energy market.

3. Good judgment must be applied to ensure evidence based information supports the need for a blanket adoption of a U.ret as low as 0.15pu. Here the route may include a NGET (Ben Marshall) scenario-study based input. Without such evidence there is a risk that the RfG adoption process will be challenged regarding unnecessary complication leading to unjustified over specifying which results in adding unnecessary cost to every type B - SPGM.

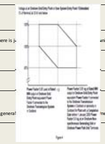
4. A key objective of RfG has been to identify key performance areas and set legal requirements across an operating parameter range. In order to support the enabling of a competitive energy market introduces a need to duly consider the adoption of such performance values at the legal minimum requirements for the majority of the network area, rather than the most stringent requirements for the minimum area of weak network?

5. For many technical reasons the type B diesel engine powered SPGM's will provide flexible P,Q&S input to the network plus most effectively support the network during system disturbances and post fault recovery. So is it not ill-considered to introduce stringent worst case scenario requirements which then discourage the availability of cost-effective, fuel efficient, low emission SPGMs by over specifying requirements just to meet the needs of a local networks bespoke shortcoming.

The above has been collated by Chris Whitworth,
AMPS Technical Specialist….22nd September 2016.

Theme	Sub Theme	Document Heading Number	Article / Heading	Table Number	Parameter	Parameter in RfG	Consultation Proposal	Article Number	Type Applicability	Justification Code	Parameter or Requirement	GE Comments	Anonymous Comments	Vestas Comments	Nordex Comments	RES Comments	Synchronous Generators Ireland Comments	Comment from Confidential Respondee	Comment from IWEA	Comments from Energia
Frequency Theme	Frequency ranges	4.1.1.1	Article 13.1 (a) (i): Frequency Ranges	2	Frequency Ranges	[illegible]	90 Minutes	13.1.a (i)	A, B, C, D PGMs and Offshore PPMs	2	parameter	The two bullet points in the justification section, on page 15, requires extended frequency ranges for the synchronous area of IE and NI beyond RfG. For instance, we note that the extended high frequency requires 60 minutes withstand capability which is longer time than GB (15minute) and therefore beyond NC RfG. The exhaustive values given in the NC RfG are binding. Extended frequency on page 15 are above RfG and may be agreed by power-generating facility in line with 13. (a). (ii), this is also highlighted in the latest Frequency Ranges IGD (31.01.2018). Can you confirm our understanding?				Agree		Additional Note on Cogeneration/PGM embedded in industrial site. RfG art 6.3 states that PGM installed in industrial installation have the right to agree on considtions for disconnecting from the grid to preserve the industrial process. This shall be reflected in the Grid Code (I could not find it, nor in the follow up meeting). This is valid also for the voltage threshold limits and ROCOF. The following sentence has been found in the clarification document. "Please note the Grid Code in Ireland also requires power-generating modules to remain connected to the network as follows: + between 47-47.5 Hz for 20 seconds + and between 51.5 -52 Hz for 60 minutes" Formally these ranges cannot be included in the future Grid Code, since not foreseen by the RfG. The 52 Hz, 60 minutes would be exceeding the present most stringent requirement in the RfG. See also last published IGD on frequency range and EC stating that MS shall avoid more stringent requirements		Increase from 60 min in current Grid Code. To be confirmed with WTG OEM's
Frequency Theme	Rate of Change of Frequency	4.1.2.1	Article 13.1 (b): RoCoF	3	The maximum RoCoF for which the Power Generating Module (PGM) shall stay connected	Not Specified	1 Hz/s over 500ms window	13.1.b	A, B, C and D PGMs and Offshore PPMs	1	parameter			It is not clear how the 1Hz/s over 500ms is to be measured. Will a generator guarantee of compliance be enough to comply? [illegible]		Agree	Synchronous Generators Ireland would be concerned about the ability of the Loss of Mains ROCOF Protection to detect true loss of mains events for SPGMs operating in trickle import scenarios, with settings of 1Hz/sec over 500ms, where the loss of mains event is localised. Our experience is that ROCOF protection relays set at 1Hz/sec over 500ms can fail to detect [illegible]			
Frequency Theme	Rate of Change of Frequency	4.1.2.1	Article 13.1 (b): RoCoF	4	The proposal for loss of mains protection (Transmission Connected)	Not Specified	1 Hz/s over 500ms window	13.1.b	A, B, C and D and Offshore PPMs	1	parameter	Clarify ROCOF protection settings from the point of view of ROCOF withstand capability. Why are they set the same and in which circumstances a transmission connected power generating unit require a ROCOF loss of main protection. the term loss of main in a Transmission context needs to be define further.				Agree				
Frequency Theme	Rate of Change of Frequency	4.1.2.1	Article 13.1 (b): RoCoF	5	The proposal for loss of mains protection (Distribution Connected)	Not Specified	[illegible]	13.1.b	A, B, C and D PGMs and Offshore PPMs	1	parameter					Agree				
Frequency Theme	Active Power Control	4.1.3.1	Article 13.4: Admissible reduction from maximum output with falling frequency	6	Admissible active power reduction from maximum output with falling frequency	[illegible]	[illegible]	13.4 (a)	A, B, C and D PGMs and Offshore PPMs	3	parameter	This is a very small value for certain technologies (such as gas engines), so we would propose to align it with other European countries and increase it (either 6%Pn/Hz or 10%Pn/Hz). We also recommend to follow the IGD document on Maximum admissible active power reduction at low frequency from 49.5 Hz for the steady state. This need to be checked from actual Gas Turbine O&M speed/power/temp performance curves.			[illegible] energy source (e.g. wind)	Agree				To be confirmed with WTG OEM's
Frequency Theme	Active Power Control	4.1.3.2	Article 13.5: Admissible reduction from maximum power with falling frequency taking account of Technical Capabilities of PGMs	7	Ambient Conditions	Not Specified	[illegible]	13.5	Gas fired SPGMs (A, B, C and D)	3	parameter	Please clarify if the specified performance applies up to 10degC only and do not apply at higher temperatures; or it applies under this particular ambient conditons only and no definite requirements otherwise.				Agree				
Frequency Theme	Active Power Control	4.1.3.3	Article 13.6: Remote operation of facility to cease active power output	8	[illegible]	A right to specify	[illegible]	13.6	A PGMs	3	requirement					No comment				
Frequency Theme	Active Power Control	4.1.3.4	Article 13.7: Automatic connection to the network	9	(1) Frequency Ranges and Time Delay	Not specific	[illegible]	13.7	A, B and C PGMs	1	parameter	Justification says 'Other generation units should not require a reduction with falling frequency.' Does it meant that 4.1.3.1 applies to gas units only ?				Clarification required - why is 5 minute delay proposed for RoI whilst 3 minute delay is proposed for Northern Ireland.				
Frequency Theme	Active Power Control	4.1.3.4	Article 13.7: Automatic connection to the network	9	(2) Maximum admissible gradient of increase in power	Not specific	10% of Pmax per minute	13.7	A, B and C PGMs	1	parameter					Clarification required- Justification mentions 3% value whilst 10% is proposed	Synchronouse Genetators Ireland [illegible]			
Frequency Theme	Active Power Control	4.1.3.4	Article 13.7: Automatic connection to the network	9	(3) Allowing automatic connection	A right to not allow	Allow	13.7	A, B and C PGMs	1	parameter					Agree				
Frequency Theme	Active Power Control	4.1.3.5	[illegible]	10	[illegible]	To specify or not to specify	[illegible]	14.2 (b)	B PGMs	3	requirement					Agree- This increases amount of generation under system operator control and and reduce grid curtailment.				The Specification of equipment by the DSO should be a colabritive process with industry and should be proposed through the forum of the DRCP and require the consent of all member to approve.
Frequency Theme	Active Power Control	4.1.3.6	[illegible]	11	[illegible]	No longer provided	[illegible]	15.2 (a)	C and D PGMs	1	parameter		This is slightly unclear, is the [illegible] follow the required ramp rate [illegible]			Agree in principle. For clarity should read "10 seconds response time plus time to reach sepoint corresponding to the ramp rate for the unit." However this may be problemmatic in a scenario where wind turbines need time to yaw up to 180 degrees into the wind after an extended period of shut down.	GE Distributed Power - [illegible]			Setting is as per WFPS Setting Schedule 6.1 with nochange for PPM's. SPGM's will be required to comply with the current operational and market monitoring tolerances.
Frequency Theme	Active Power Control	4.1.3.6	[illegible]	11	[illegible]	Not Provided	[illegible]	15.2 (a)	C and D PGMs	3	parameter	1MW or 1 % accuray dispatch would require further discussion with all PGMs technology.				Active power tolerance of 3% all the time may be challenging in the case of a fluctuating resource. Consideration be given to setting limits based on suitable averaging period say say 10s, 1 min or so. Discussion with OEMs is necessary to agree suitable specification.	Caterpillar Energy Solutions [illegible]			
Frequency Theme	Frequency Modes	4.1.4.1	[illegible]	12	Frequency threshold	[illegible]	[illegible]	13.2 (a)	A, B, C and D PGMs & offshore PPMs	2	parameter	In section 4.1.4 (frequency modes), a figure and clarification with all operation modes (LFSM-U, FSM and LFSM-O) should be included to understand how they relate, interact and what performance is proposed. For instance, Article 15 (2) d says, "in addition to point (c) of paragraph 2, the following shall apply cumulatively when frequency sensitive mode ('FSM') is operating", this means that when FSM is selected, LSFM-U and LFSM-O are also operating in parallel. This should be clarified by showing the combine requirement LFSM-O, LFSM-U and FSM as defined in RfG requirement and limitation of each mode.				Agree				To be confirmed with WTG OEM's
Frequency Theme	Frequency Modes	4.1.4.1	[illegible]	12	[illegible]	[illegible]	[illegible]	13.2 (a)	A, B, C and D PGMs & offshore PPMs	2	parameter					Agree				
Frequency Theme	Frequency Modes	4.1.4.2	[illegible]	13	[illegible]	[illegible]	[illegible]	13.2 (e)	A PGMs	3	requirement					No comment				
Frequency Theme	Frequency Modes	4.1.4.4	[illegible]	14	[illegible]	[illegible]	[illegible]	13.2 (f)	A, B, C and D PGMs & offshore PPMs	1	requirement					Agree-in line current Grid Code				
Frequency Theme	Frequency Modes	4.1.4.5	[illegible]	15	Frequency threshold	[illegible]	[illegible]	15.2 (c)	C and D PGMs & offshore PPMs	1	parameter					Agree-in line with current Grid Code				
Frequency Theme	Frequency Modes	4.1.4.5	[illegible]	15	Droop settings	[illegible]	[illegible]	15.2 (c)	C and D PGMs & offshore PPMs	1	parameter					Agree				
Frequency Theme	Frequency Modes	4.1.4.6	[illegible]	16	[illegible]	[illegible]	[illegible]	[illegible]	C and D PGMs & offshore PPMs	1	parameter	The Final IGD published on 31.01.2018 provide some clarification on this parameter, however the consultation paper refers this as an error from ENTSO-E. We suggest to align this parameter with the latest IGD and seek further clarification with industry. For instance, GB is proposing a value for "active power range" of 10%Pn. See comment in row 16 above				Agree				
Frequency Theme	Frequency Modes	4.1.4.6	[illegible]	16	[illegible]	[illegible]	[illegible]	[illegible]	C and D PGMs & offshore PPMs	3	parameter					Agree				Acceptable as 15mHz remains maximum absolute value
Frequency Theme	Frequency Modes	4.1.4.6	[illegible]	16	[illegible]	[illegible]	[illegible]	[illegible]	C and D PGMs & offshore PPMs	3	parameter					Agree				To be confirmed with WTG OEM's
Frequency Theme	Frequency Modes	4.1.4.6	[illegible]	16	[illegible]	[illegible]	[illegible]	[illegible]	C and D PGMs & offshore PPMs	3	parameter					Agree				To be confirmed with WTG OEM's
Frequency Theme	Frequency Modes	4.1.4.6	[illegible]	16	Droop	[illegible]	[illegible]	[illegible]	C and D PGMs & offshore PPMs	1	parameter					Agree				No Change to current Grid Code requirements - Acceptable
Frequency Theme	Frequency Modes	4.1.4.7	[illegible]	17	[illegible]	[illegible]	[illegible]	[illegible]	C and D PGMs & offshore PPMs	3	parameter	1- Define and Clarify what is 100% in a multiple-units power plant (eg CCGT) 2-Requirements shall be on an equality principle, it's recommended to harmonize those parameters at synchronous area level between EirGrid/ESB networks and NIE/ NIE network.	As the intention is to retain th[illegible] regarding the required active [illegible] form of additional guidance w[illegible] Could EirGrid also provide fur[illegible] response when increasing fro[illegible] and during periods of low win[illegible]		[illegible] is the future or will the logic [illegible]	Clarification required - Noting that this parameter does not superceed Grid Code requirement for 60% increase in power in 5s and 100% in 15s., how is this parameter going to be applied.	GE Distributed Power - the [illegible]			To be confirmed with WTG OEM's
Frequency Theme	Frequency Modes	4.1.4.7	[illegible]	17	[illegible]	[illegible]	[illegible]	[illegible]	C and D PGMs & offshore PPMs	3	parameter		There will always be delays i[illegible] the controller cyle time and t[illegible] proposal would be 1 s. Ancillary services contracts t[illegible] fast response (e.g. batteries) [illegible]			Agree -taking into account TSO explanation that current drafting allows for any inherent delay to be considred and accepted if reasonable.				To be confirmed with WTG OEM's
Frequency Theme	Frequency Modes	4.1.4.7	[illegible]	17	[illegible]	[illegible]	[illegible]	[illegible]	C and D PGMs & offshore PPMs	3	parameter	1-Clarify if this requirement applies at the entire plant in multishift CCGT configuration or at unit level 2-Requirements shall be on an equality principle, it's recommended to harmonize those parameters at synchronous area level between EirGrid/ESB networks and NIE/ NIE network. The full acivation time t2 proposal is three times lower than the proposed 15sec in Table 2 of the final IGD on Frequency sensitive mode (31-01-2018). we also note that the Northern Ireland consultation template propose 15 second. 3-Time t2 (5 sec) to achieve the full output includes the time t1 (2 sec) for the max delay. It makes the response time after the delay equals 3 sec and 5%, which is demanding. Refer to Figure 6 of RfG.				Clarification required - Noting that this parameter does not superceed Grid Code requirement for 60% increase in power in 5s and 100% in 15s., how is this parameter going to be applied.				5 sec is in line with existing MFS .Acceptable
Frequency Theme	Frequency Modes	4.1.4.7	[illegible]	17	[illegible]	[illegible]	[illegible]	[illegible]	C and D PGMs & offshore PPMs	3	parameter					Do not agree - Appreciate that the RfG requires the specification of a value in the range 15-30 minutes. However as the current grid code does not require all generators to provide TOR2 the proposal is a significant new requirement which should be justified if greater than the minimum permitted value.				
Frequency Theme	Non-Mandatory Frequency Requirements that we are not invoking at this time	4.1.5	[illegible]	18	[illegible]	Not specified	[illegible]	[illegible]	[illegible]	N/A	requirement					Agree - agreement via System Services Contract means it is non-mandatory.				
Frequency Theme	Non-Mandatory Frequency Requirements that we are not invoking at this time	4.1.5	[illegible]	18	[illegible]	Not specified	[illegible]	[illegible]	[illegible]	N/A	requirement					Agree - agreement via System Services Contract means it is non-mandatory.				
Voltage Theme	Automatic Disconnection Due to Voltage Level	4.2.1.1	[illegible]	19	[illegible]	Not specified	[illegible]	15.3	[illegible]	1	parameter					Agree - values are as in Conditions Governing Connection to the Distribution System				
Voltage Theme	Automatic Disconnection Due to Voltage Level	4.2.1.1	[illegible]	19	[illegible]	Not specified	[illegible]	15.3	[illegible]	1	parameter					Agree - values are as in Conditions Governing Connection to the Distribution System				
Voltage Theme	Automatic Disconnection Due to Voltage Level	4.2.1.1	[illegible]	19	[illegible]	Not specified	[illegible]	15.3	[illegible]	1	parameter					Agree - values are as in Conditions Governing Connection to the Distribution System				
Voltage Theme	Automatic Disconnection Due to Voltage Level	4.2.1.1	[illegible]	19	[illegible]	Not specified	[illegible]	15.3	[illegible]	1	parameter					Agree - values are as in Conditions Governing Connection to the Distribution System				
Voltage Theme	Automatic Disconnection Due to Voltage Level	4.2.1.1	[illegible]	19	[illegible]	Not specified	[illegible]	15.3	[illegible]	1	parameter					Agree - values are as in Conditions Governing Connection to the Distribution System				
Voltage Theme	Automatic Disconnection Due to Voltage Level	4.2.1.2	[illegible]	20	[illegible]	Not specified	Not Allowed	[illegible]	D PGMs	1	parameter					More clarity required-Is "Not Allowed" consistent with generator interface protection which disconnects generator below a certain voltage? Generators must have the right to disconnect if voltages fall below planning limits and may cause equipment damange.				
Voltage Theme	Automatic Disconnection Due to Voltage Level	4.2.1.2	[illegible]	20	[illegible]	Not specified	Not Allowed	[illegible]	D PGMs	1	parameter					More clarity required-Is "Not Allowed" consistent with ith generator interface protection which disconnects generator abovea certain voltage? Generators must have the right to disconnect if voltages exceed planning limits and may cause equipment damange.				
Voltage Theme	Automatic Disconnection Due to Voltage Level	4.2.1.2	[illegible]	21	[illegible]	Not specified	[illegible]	[illegible]	[illegible]	1	parameter					Agree - values are as in Conditions Governing Connection to the Distribution System				
Voltage Theme	Automatic Disconnection Due to Voltage Level	4.2.1.2	[illegible]	21	[illegible]	Not specified	[illegible]	[illegible]	[illegible]	1	parameter					Agree - values are as in Conditions Governing Connection to the Distribution System				
Voltage Theme	Automatic Disconnection Due to Voltage Level	4.2.1.2	[illegible]	21	[illegible]	Not specified	[illegible]	[illegible]	[illegible]	1	parameter					Agree - values are as in Conditions Governing Connection to the Distribution System				
Voltage Theme	Automatic Disconnection Due to Voltage Level	4.2.1.2	[illegible]	21	[illegible]	Not specified	[illegible]	[illegible]	[illegible]	1	parameter					Agree - values are as in Conditions Governing Connection to the Distribution System				
Voltage Theme	Automatic Disconnection Due to Voltage Level	4.2.1.2	[illegible]	21	[illegible]	Not specified	[illegible]	[illegible]	[illegible]	1	parameter					Agree - values are as in Conditions Governing Connection to the Distribution System				
Voltage Theme	Reactive Power Capability for Type B PGMs	4.2.2.1.1	[illegible]	22	[illegible]	To specify or not to specify	[illegible]	[illegible]	[illegible]	1	requirement					No comment				
Voltage Theme	Reactive Power Capability for Type B PGMs	4.2.2.1.1	[illegible]	23	[illegible]	To specify or not to specify	[illegible]	[illegible]	[illegible]	1	requirement					No comment				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.2.1	[illegible]	24	[illegible]	[illegible]	[illegible]	[illegible]	D SPGMs	[illegible]	parameter					No comment				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.2.1	[illegible]	24	[illegible]	[illegible]	[illegible]	[illegible]	D SPGMs	[illegible]	parameter					No comment				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.2.1	[illegible]	24	[illegible]	[illegible]	[illegible]	[illegible]	D SPGMs	[illegible]	parameter					No comment	Caterpillar Energy Solutions [illegible] Pmax/Qmax is very wide for [illegible] be used.			
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.2.1	[illegible]	24	[illegible]	[illegible]	[illegible]	[illegible]	D SPGMs	[illegible]	parameter					No comment				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.2.1	[illegible]	24	[illegible]	[illegible]	[illegible]	[illegible]	D SPGMs	[illegible]	parameter					No comment				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.2.1	[illegible]	24	[illegible]	[illegible]	[illegible]	[illegible]	D SPGMs	[illegible]	parameter					No comment				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.2.1	[illegible]	24	[illegible]	[illegible]	[illegible]	[illegible]	D SPGMs	[illegible]	parameter					No comment	Caterpillar Energy Solutions [illegible] Pmax/Qmax is very wide for [illegible] be used.			
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.2.1	[illegible]	24	[illegible]	[illegible]	[illegible]	[illegible]	D SPGMs	[illegible]	parameter					No comment				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.2.1	[illegible]	24	[illegible]	[illegible]	[illegible]	[illegible]	D SPGMs	[illegible]	parameter					No comment				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.2.1	[illegible]	24	[illegible]	[illegible]	[illegible]	[illegible]	D SPGMs	[illegible]	parameter					No comment				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.2.1	[illegible]	24	[illegible]	[illegible]	[illegible]	[illegible]	D SPGMs	[illegible]	parameter					No comment	Caterpillar Energy Solutions [illegible] Pmax/Qmax is very wide for [illegible] be used.			
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.2.1	[illegible]	24	[illegible]	[illegible]	[illegible]	[illegible]	D SPGMs	[illegible]	parameter					No comment				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.2.1	[illegible]	25	[illegible]	[illegible]	[illegible]	[illegible]	C and D SPGMs	[illegible]	parameter					No comment				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.2.1	[illegible]	25	[illegible]	[illegible]	[illegible]	[illegible]	C and D SPGMs	[illegible]	parameter					No comment				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.2.1	[illegible]	25	[illegible]	[illegible]	[illegible]	[illegible]	C and D SPGMs	[illegible]	parameter					No comment				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.2.1	[illegible]	25	[illegible]	[illegible]	[illegible]	[illegible]	C and D SPGMs	[illegible]	parameter					No comment				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.2.1	[illegible]	25	[illegible]	[illegible]	[illegible]	[illegible]	C and D SPGMs	[illegible]	parameter					No comment				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.2.1	[illegible]	25	[illegible]	[illegible]	[illegible]	[illegible]	C and D SPGMs	[illegible]	parameter					No comment				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.2.1	[illegible]	25	[illegible]	[illegible]	[illegible]	[illegible]	C and D SPGMs	[illegible]	parameter					No comment				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.2.1	[illegible]	25	[illegible]	[illegible]	[illegible]	[illegible]	C and D SPGMs	[illegible]	parameter	[illegible]				No comment				

Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.2	Article 18.2.b. (iv): SPGM: Time to Achieve Target Value within U-Q/Pmax Profiles	25	Time to achieve target value (transmission connected)	Not specified	Without undue delay but at least within 120 seconds	18.2.b.(iv)	C and D SPGMs	1	parameter	The proposed value of 120 second time scale shall be increased. To move from full lagging to full leading requires to use GSU tap changer on large generating units. 120 second time scale to achieve extreme operating Qmin, Qmax points by moving and instructing the GSU tap changer tap will take longer than 120 second since several tap instructions will be required. What typical tap-changer operation time per tap have been assumed?				No comment				Alligned with Ireland Grid Code and scheduling and dispatch code - Acceptable
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.2	Article 18.2.b. (iv): SPGM: Time to Achieve Target Value within U-Q/Pmax Profiles	26	Time to achieve target value (distribution connected)	Not specified	Without undue delay but at least within 120 seconds	18.2.b.(iv)	C and D SPGMs	3	parameter	Same as row 66				No comment				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.3	Article 21.3.b.(i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	27	umin (110 kV)	0.875 p.u.	0.9 p.u.	21.3.b.(ii)	D PPMs	1	parameter					Agree				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.3	Article 21.3.b.(i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	27	umax (110 kV)	1.1 p.u.	1.1 p.u.	21.3.b.(ii)	D PPMs	2	parameter					Agree				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.3	Article 21.3.b.(i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	27	Qmin/Pmax (lead) (110 kV)	-0.5 p.u.	-0.33 p.u.	21.3.b.(ii)	D PPMs	1	parameter					More clarity required.The propopsal Specifies a reactive power Qmin with reference to a Pmax and Qmin must be available at all power levels.RFG says "*The specified U-Q/Pmax profile may take any shape, having regard to the potential costs of delivering the capability to provide reactive power production at high voltages and reactive power consumption at low voltages;*" It is not clear what shape TSO has chosen within the specified U and Q/Pmax coordinates. We assume a rectangle corresponding to these coordinates but this is not stated.				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.3	Article 21.3.b.(i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	27	Qmax/Pmax (lag) (110 kV)	0.65 p.u.	0.33 p.u.	21.3.b.(ii)	D PPMs	1	parameter					More clarity required.The propopsal Specifies a reactive power Qmax with reference to a Pmax and Qmin must be available at all power levels.RFG says "*The specified U-Q/Pmax profile may take any shape, having regard to the potential costs of delivering the capability to provide reactive power production at high voltages and reactive power consumption at low voltages;*" It is not clear what shape TSO has chosen within the specified U and Q/Pmax coordinates. We assume a rectangle corresponding to these coordinates but this is not stated.				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.3	Article 21.3.b.(i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	27	umin (220 kV)	0.875 p.u.	0.9 p.u.	21.3.b.(ii)	D PPMs	2	parameter					Agree				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.3	Article 21.3.b.(i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	27	umax (220 kV)	1.1 p.u.	1.1 p.u.	21.3.b.(ii)	D PPMs	2	parameter					Agree				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.3	Article 21.3.b.(i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	27	Qmin/Pmax (lead) (220 kV)	-0.5 p.u.	-0.33 p.u.	21.3.b.(ii)	D PPMs	1	parameter					More clarity required.The propopsal Specifies a reactive power Qmin with reference to a Pmax and Qmin must be available at all power levels.RFG says "*The specified U-Q/Pmax profile may take any shape, having regard to the potential costs of delivering the capability to provide reactive power production at high voltages and reactive power consumption at low voltages;*" It is not clear what shape TSO has chosen within the specified U and Q/Pmax coordinates. We assume a rectangle corresponding to these coordinates but this is not stated.				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.3	Article 21.3.b.(i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	27	Qmax/Pmax (lag) (220 kV)	0.65 p.u.	0.33 p.u.	21.3.b.(ii)	D PPMs	1	parameter					More clarity required.The propopsal Specifies a reactive power Qmax with reference to a Pmax and Qmin must be available at all power levels.RFG says "*The specified U-Q/Pmax profile may take any shape, having regard to the potential costs of delivering the capability to provide reactive power production at high voltages and reactive power consumption at low voltages;*" It is not clear what shape TSO has chosen within the specified U and Q/Pmax coordinates. We assume a rectangle corresponding to these coordinates but this is not stated.				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.3	Article 21.3.b.(i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	27	umin (400 kV)	0.875 p.u.	0.875 p.u.	21.3.b.(ii)	D PPMs	1	parameter					Agree				Alligned with Ireland Grid Code and scheduling and dispatch code - Acceptable
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.3	Article 21.3.b.(i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	27	umax (400 kV)	1.1 p.u.	1.05 p.u.	21.3.b.(ii)	D PPMs	1	parameter					Agree				Alligned with Ireland Grid Code and scheduling and dispatch code - Acceptable
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.3	Article 21.3.b.(i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	27	Qmin/Pmax (lead) (400 kV)	-0.5 p.u.	-0.33 p.u.	21.3.b.(ii)	D PPMs	1	parameter					More clarity required.The propopsal Specifies a reactive power Qmin with reference to a Pmax and Qmin must be available at all power levels.RFG says "*The specified U-Q/Pmax profile may take any shape, having regard to the potential costs of delivering the capability to provide reactive power production at high voltages and reactive power consumption at low voltages;*" It is not clear what shape TSO has chosen within the specified U and Q/Pmax coordinates. We assume a rectangle corresponding to these coordinates but this is not stated.				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.3	Article 21.3.b.(i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	27	Qmax/Pmax (lag) (400 kV)	0.65 p.u.	0.33 p.u.	21.3.b.(ii)	D PPMs	1	parameter					More clarity required.The propopsal Specifies a reactive power Qmax with reference to a Pmax and Qmin must be available at all power levels.RFG says "*The specified U-Q/Pmax profile may take any shape, having regard to the potential costs of delivering the capability to provide reactive power production at high voltages and reactive power consumption at low voltages;*" It is not clear what shape TSO has chosen within the specified U and Q/Pmax coordinates. We assume a rectangle corresponding to these coordinates but this is not stated.				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.3	Article 21.3.b.(i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	28	umin (10 kV and 20kV topology 1)	0.875 p.u.	0.96 p.u.	21.3.b.(ii)	C and D PPM	1	parameter					Agree				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.3	Article 21.3.b.(i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	28	umax (10 kV and 20kV topology 1)	1.1 p.u.	1.1 p.u.	21.3.b.(ii)	C and D PPM	1	parameter					Agree				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.3	Article 21.3.b.(i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	28	Qmin/Pmax (lead) (10 kV and 20kV topology 1)	-0.5 p.u.	-0.33 p.u.	21.3.b.(ii)	C and D PPM	1	parameter					More clarity required.The propopsal Specifies a reactive power Qmin with reference to a Pmax and Qmin must be available at all power levels.RFG says "*The specified U-Q/Pmax profile may take any shape, having regard to the potential costs of delivering the capability to provide reactive power production at high voltages and reactive power consumption at low voltages;*" It is not clear what shape TSO has chosen within the specified U and Q/Pmax coordinates. We assume a rectangle corresponding to these coordinates but this is not stated.				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.3	Article 21.3.b.(i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	28	Qmax/Pmax (lag) (10 kV and 20kV topology 1)	0.65 p.u.	0.33 p.u.	21.3.b.(ii)	C and D PPM	1	parameter					More clarity required.The propopsal Specifies a reactive power Qmax with reference to a Pmax and Qmin must be available at all power levels.RFG says "*The specified U-Q/Pmax profile may take any shape, having regard to the potential costs of delivering the capability to provide reactive power production at high voltages and reactive power consumption at low voltages;*" It is not clear what shape TSO has chosen within the specified U and Q/Pmax coordinates. We assume a rectangle corresponding to these coordinates but this is not stated.				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.3	Article 21.3.b.(i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	28	umin (38 kV topology 1)	0.875 p.u.	0.937 p.u.	21.3.b.(ii)	C and D PPM	1	parameter					Agree				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.3	Article 21.3.b.(i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	28	umax (38 kV topology 1)	1.1 p.u.	1.1 p.u.	21.3.b.(ii)	C and D PPM	1	parameter					Agree				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.3	Article 21.3.b.(i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	28	Qmin/Pmax (lead) (38 kV topology 1)	-0.5 p.u.	-0.33 p.u.	21.3.b.(ii)	C and D PPM	1	parameter					More clarity required.The propopsal Specifies a reactive power Qmin with reference to a Pmax and Qmin must be available at all power levels.RFG says "*The specified U-Q/Pmax profile may take any shape, having regard to the potential costs of delivering the capability to provide reactive power production at high voltages and reactive power consumption at low voltages;*" It is not clear what shape TSO has chosen within the specified U and Q/Pmax coordinates. We assume a rectangle corresponding to these coordinates but this is not stated.				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.3	Article 21.3.b.(i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	28	Qmax/Pmax (lag) (38 kV topology 1)	0.65 p.u.	0.33 p.u.	21.3.b.(ii)	C and D PPM	1	parameter					More clarity required.The propopsal Specifies a reactive power Qmax with reference to a Pmax and Qmin must be available at all power levels.RFG says "*The specified U-Q/Pmax profile may take any shape, having regard to the potential costs of delivering the capability to provide reactive power production at high voltages and reactive power consumption at low voltages;*" It is not clear what shape TSO has chosen within the specified U and Q/Pmax coordinates. We assume a rectangle corresponding to these coordinates but this is not stated.				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.3	Article 21.3.b.(i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	29	umin (10 kV and 20kV all other topologies)	0.875 p.u.	0.96 p.u.	21.3.b.(ii)	C and D PPM	1	parameter					Agree				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.3	Article 21.3.b.(i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	29	umax (10 kV and 20kV all other topologies)	1.1 p.u.	1.1 p.u.	21.3.b.(ii)	C and D PPM	2	parameter					Agree				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.3	Article 21.3.b.(i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	29	Qmin/Pmax (lead) (10 kV and 20kV all other topologies)	-0.5 p.u.	-0.42 p.u.	21.3.b.(ii)	C and D PPM	1	parameter					More clarity required.The propopsal Specifies a reactive power Qmin with reference to a Pmax and Qmin must be available at all power levels.RFG says "*The specified U-Q/Pmax profile may take any shape, having regard to the potential costs of delivering the capability to provide reactive power production at high voltages and reactive power consumption at low voltages;*" It is not clear what shape TSO has chosen within the specified U and Q/Pmax coordinates. We assume a rectangle corresponding to these coordinates but this is not stated.				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.3	Article 21.3.b.(i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	29	Qmax/Pmax (lag) (10 kV and 20kV all other topologies)	0.65 p.u.	0 p.u.	21.3.b.(ii)	C and D PPM	1	parameter					More clarity required.The propopsal Specifies a reactive power Qmax with reference to a Pmax and Qmin must be available at all power levels.RFG says "*The specified U-Q/Pmax profile may take any shape, having regard to the potential costs of delivering the capability to provide reactive power production at high voltages and reactive power consumption at low voltages;*" It is not clear what shape TSO has chosen within the specified U and Q/Pmax coordinates. We assume a rectangle corresponding to these coordinates but this is not stated.				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.3	Article 21.3.b.(i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	29	umin (38 kV all other topologies)	0.875 p.u.	0.937 p.u.	21.3.b.(ii)	C and D PPM	1	parameter					Agree				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.3	Article 21.3.b.(i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	29	umax (38 kV all other topologies)	1.1 p.u.	1.1 p.u.	21.3.b.(ii)	C and D PPM	1	parameter					Agree				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.3	Article 21.3.b.(i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	29	Qmin/Pmax (lead) (38 kV all other topologies)	-0.5 p.u.	-0.42 p.u.	21.3.b.(ii)	C and D PPM	1	parameter					More clarity required.The propopsal Specifies a reactive power Qmin with reference to a Pmax and Qmin must be available at all power levels.RFG says "*The specified U-Q/Pmax profile may take any shape, having regard to the potential costs of delivering the capability to provide reactive power production at high voltages and reactive power consumption at low voltages;*" It is not clear what shape TSO has chosen within the specified U and Q/Pmax coordinates. We assume a rectangle corresponding to these coordinates but this is not stated.				
Voltage Theme	Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles	4.2.2.3	Article 21.3.b.(i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	29	Qmax/Pmax (lag) (38 kV all other topologies)	0.65 p.u.	0 p.u.	21.3.b.(ii)	C and D PPM	1	parameter					More clarity required.The propopsal Specifies a reactive power Qmax with reference to a Pmax and Qmin must be available at all power levels.RFG says "*The specified U-Q/Pmax profile may take any shape, having regard to the potential costs of delivering the capability to provide reactive power production at high voltages and reactive power consumption at low voltages;*" It is not clear what shape TSO has chosen within the specified U and Q/Pmax coordinates. We assume a rectangle corresponding to these coordinates but this is not stated.				
Voltage Theme	Reactive Power Capability below Maximum Capacity: P-Q/Pmax Profiles	4.2.3.1	Article 21.3.c.(ii), (iii) and (iv): PPM: Parameters required for P-Q/Pmax Profiles	30	pmin (110 to 400kV)	0.0 p.u.	0.12 p.u.	21.3.c.(ii)	D PPMs	1	parameter					Agree				
Voltage Theme	Reactive Power Capability below Maximum Capacity: P-Q/Pmax Profiles	4.2.3.1	Article 21.3.c.(ii), (iii) and (iv): PPM: Parameters required for P-Q/Pmax Profiles	30	pmax (110 to 400kV)	1.0 p.u.	1.0 p.u.	21.3.c.(ii)	D PPMs	1	parameter					Agree				
Voltage Theme	Reactive Power Capability below Maximum Capacity: P-Q/Pmax Profiles	4.2.3.1	Article 21.3.c.(ii), (iii) and (iv): PPM: Parameters required for P-Q/Pmax Profiles	30	Qmin/Pmax (lead) (110 to 400kV)	-0.5 p.u.	-0.33 p.u.	21.3.c.(ii)	D PPMs	1	parameter					More clarity required.The propopsal Specifies a reactive power Qmin with reference to a Pmax and Qmin must be available at all power levels.RFG says "*The specified U-Q/Pmax profile may take any shape, having regard to the potential costs of delivering the capability to provide reactive power production at high voltages and reactive power consumption at low voltages;*" It is not clear what shape TSO has chosen within the specified U and Q/Pmax coordinates. We assume a rectangle corresponding to these coordinates but this is not stated.				
Voltage Theme	Reactive Power Capability below Maximum Capacity: P-Q/Pmax Profiles	4.2.3.1	Article 21.3.c.(ii), (iii) and (iv): PPM: Parameters required for P-Q/Pmax Profiles	30	Qmax/Pmax (lag) (110 to 400kV)	0.65 p.u.	0.33 p.u.	21.3.c.(ii)	D PPMs	1	parameter					More clarity required.The propopsal Specifies a reactive power Qmax with reference to a Pmax and Qmin must be available at all power levels.RFG says "*The specified U-Q/Pmax profile may take any shape, having regard to the potential costs of delivering the capability to provide reactive power production at high voltages and reactive power consumption at low voltages;*" It is not clear what shape TSO has chosen within the specified U and Q/Pmax coordinates. We assume a rectangle corresponding to these coordinates but this is not stated.				
Voltage Theme	Reactive Power Capability below Maximum Capacity: P-Q/Pmax Profiles	4.2.3.1	Article 21.3.c.(ii), (iii) and (iv): PPM: Parameters required for P-Q/Pmax Profiles	31	pmin (10kV, 20kV or 38kV topology 2)	0.0 p.u.	0.12 p.u.	21.3.c.(ii)	C and D PPM	1	parameter					Agree				
Voltage Theme	Reactive Power Capability below Maximum Capacity: P-Q/Pmax Profiles	4.2.3.1	Article 21.3.c.(ii), (iii) and (iv): PPM: Parameters required for P-Q/Pmax Profiles	31	pmax (10kV, 20kV or 38kV topology 2)	1.0 p.u.	1.0 p.u.	21.3.c.(ii)	C and D PPM	1	parameter					Agree				
Voltage Theme	Reactive Power Capability below Maximum Capacity: P-Q/Pmax Profiles	4.2.3.1	Article 21.3.c.(ii), (iii) and (iv): PPM: Parameters required for P-Q/Pmax Profiles	31	Qmin/Pmax (lead) (10kV, 20kV or 38kV topology 2)	-0.5 p.u.	-0.33 p.u.	21.3.c.(ii)	C and D PPM	1	parameter					More clarity required.The propopsal Specifies a reactive power Qmin with reference to a Pmax and Qmin must be available at all power levels.RFG says "*The specified U-Q/Pmax profile may take any shape, having regard to the potential costs of delivering the capability to provide reactive power production at high voltages and reactive power consumption at low voltages;*" It is not clear what shape TSO has chosen within the specified U and Q/Pmax coordinates. We assume a rectangle corresponding to these coordinates but this is not stated.				
Voltage Theme	Reactive Power Capability below Maximum Capacity: P-Q/Pmax Profiles	4.2.3.1	Article 21.3.c.(ii), (iii) and (iv): PPM: Parameters required for P-Q/Pmax Profiles	31	Qmax/Pmax (lag) (10kV, 20kV or 38kV topology 2)	0.65 p.u.	0.33 p.u.	21.3.c.(ii)	C and D PPM	1	parameter					More clarity required.The propopsal Specifies a reactive power Qmax with reference to a Pmax and Qmin must be available at all power levels.RFG says "*The specified U-Q/Pmax profile may take any shape, having regard to the potential costs of delivering the capability to provide reactive power production at high voltages and reactive power consumption at low voltages;*" It is not clear what shape TSO has chosen within the specified U and Q/Pmax coordinates. We assume a rectangle corresponding to these coordinates but this is not stated.				
Voltage Theme	Reactive Power Capability below Maximum Capacity: P-Q/Pmax Profiles	4.2.3.1	Article 21.3.c.(ii), (iii) and (iv): PPM: Parameters required for P-Q/Pmax Profiles	32	pmin (10kV, 20kV or 38kV Topology 1 & 3)	0.0 p.u.	0.12 p.u.	21.3.c.(ii)	C and D PPM	1	parameter					Agree				
Voltage Theme	Reactive Power Capability below Maximum Capacity: P-Q/Pmax Profiles	4.2.3.1	Article 21.3.c.(ii), (iii) and (iv): PPM: Parameters required for P-Q/Pmax Profiles	32	pmax (10kV, 20kV or 38kV Topology 1 & 3)	1.0 p.u.	1.0 p.u.	21.3.c.(ii)	C and D PPM	1	parameter					Agree				
Voltage Theme	Reactive Power Capability below Maximum Capacity: P-Q/Pmax Profiles	4.2.3.1	Article 21.3.c.(ii), (iii) and (iv): PPM: Parameters required for P-Q/Pmax Profiles	32	Qmin/Pmax (lead) (10kV, 20kV or 38kV Topology 1 & 3)	-0.5 p.u.	Power factor range from 0.92 (-0.42 Q / Pmax) to unity (0 Q/Pmax)	21.3.c.(ii)	C and D PPM	1	parameter					More clarity required.The propopsal Specifies a reactive power Qmin with reference to a Pmax and Qmin must be available at all power levels.RFG says "*The specified U-Q/Pmax profile may take any shape, having regard to the potential costs of delivering the capability to provide reactive power production at high voltages and reactive power consumption at low voltages;*" It is not clear what shape TSO has chosen within the specified U and Q/Pmax coordinates. We assume a rectangle corresponding to these coordinates but this is not stated.				
Voltage Theme	Reactive Power Capability below Maximum Capacity: P-Q/Pmax Profiles	4.2.3.1	Article 21.3.c.(ii), (iii) and (iv): PPM: Parameters required for P-Q/Pmax Profiles	32	Qmax/Pmax (lag) (10kV, 20kV or 38kV Topology 1 & 3)	0.65 p.u.	Power factor range from 0.92 (-0.42 Q / Pmax) to unity (0 Q/Pmax)	21.3.c.(ii)	C and D PPM	1	parameter					More clarity required.The propopsal Specifies a reactive power Qmax with reference to a Pmax and Qmin must be available at all power levels.RFG says "*The specified U-Q/Pmax profile may take any shape, having regard to the potential costs of delivering the capability to provide reactive power production at high voltages and reactive power consumption at low voltages;*" It is not clear what shape TSO has chosen within the specified U and Q/Pmax coordinates. We assume a rectangle corresponding to these coordinates but this is not stated.				
Voltage Theme	Reactive Power Capability below Maximum Capacity: P-Q/Pmax Profiles	4.2.3.1	Article 21.3.c.(ii), (iii) and (iv): PPM: Parameters required for P-Q/Pmax Profiles	33	pmin (10kV, 20kV or 38kV Topology 5)	0.0 p.u.	0.12 p.u.	21.3.c.(ii)	C and D PPM	1	parameter					Agree				
Voltage Theme	Reactive Power Capability below Maximum Capacity: P-Q/Pmax Profiles	4.2.3.1	Article 21.3.c.(ii), (iii) and (iv): PPM: Parameters required for P-Q/Pmax Profiles	33	pmax (10kV, 20kV or 38kV Topology 5)	1.0 p.u.	1.0 p.u.	21.3.c.(ii)	C and D PPM	1	parameter					Agree				
Voltage Theme	Reactive Power Capability below Maximum Capacity: P-Q/Pmax Profiles	4.2.3.1	Article 21.3.c.(ii), (iii) and (iv): PPM: Parameters required for P-Q/Pmax Profiles	33	Qmin/Pmax (lead) (10kV, 20kV or 38kV Topology 5)	-0.5 p.u.	Power factor range from 0.92 (-0.42 Q / Pmax) to 0.95 (0.33 Q/Pmax)	21.3.c.(ii)	C and D PPM	1	parameter					More clarity required.The propopsal Specifies a reactive power Qmin with reference to a Pmax and Qmin must be available at all power levels.RFG says "*The specified U-Q/Pmax profile may take any shape, having regard to the potential costs of delivering the capability to provide reactive power production at high voltages and reactive power consumption at low voltages;*" It is not clear what shape TSO has chosen within the specified U and Q/Pmax coordinates. We assume a rectangle corresponding to these coordinates but this is not stated.				
Voltage Theme	Reactive Power Capability below Maximum Capacity: P-Q/Pmax Profiles	4.2.3.1	Article 21.3.c.(ii), (iii) and (iv): PPM: Parameters required for P-Q/Pmax Profiles	33	Qmax/Pmax (lag) (10kV, 20kV or 38kV Topology 5)	0.65 p.u.	Power factor range from 0.92 (-0.42 Q / Pmax) to 0.95 (0.33 Q/Pmax)	21.3.c.(ii)	C and D PPM	1	parameter					More clarity required.The propopsal Specifies a reactive power Qmax with reference to a Pmax and Qmin must be available at all power levels.RFG says "*The specified U-Q/Pmax profile may take any shape, having regard to the potential costs of delivering the capability to provide reactive power production at high voltages and reactive power consumption at low voltages;*" It is not clear what shape TSO has chosen within the specified U and Q/Pmax coordinates. We assume a rectangle corresponding to these coordinates but this is not stated.				
Voltage Theme	Reactive Power Capability below Maximum Capacity: P-Q/Pmax Profiles	4.2.3.2	Article 21.3.c.(v): PPM: Time to Achieve Target Value within P-Q/Pmax Profile	34	Time to achieve target value (transmission connected)	Not specified	Without delay but within 20 seconds	21.3.c.(v)	C and D PPMs	1	parameter					Agree				
Voltage Theme	Reactive Power Capability below Maximum Capacity: P-Q/Pmax Profiles	4.2.3.2	Article 21.3.c.(v): PPM: Time to Achieve Target Value within P-Q/Pmax Profile	34	Time to achieve target value (distribution connected)	Not specified	Without delay but within 20 seconds	21.3.c.(v)	C and D PPMs	1	parameter					Agree				
Voltage Theme	Supplementary Reactive Power Requirements	4.2.4.1	Article 18.3.a: SPGM: Supplementary reactive power requirements	35	Right to specify supplementary reactive power requirements when the connection point is remote	To specify or not to specify	RSOs reserve the right to specify	18.3.a	Type C and D SPGMs	1	requirement					More clarity required-Care should be taken not to specify reactive power capability that gives rise to voltage rise issues. For instance remote connection points benefit from more importing reactive power capability and not more exporting reactive power capability.				
Voltage Theme	Supplementary Reactive Power Requirements	4.2.4.2	Article 21.3.a: PPM: Supplementary reactive power requirements	36	Right to specify supplementary reactive power requirements when the connection point is remote	To specify or not to specify	RSOs reserve the right to specify	21.3.a	Type C and D PPMs	1	requirement					More clarity required-Care should be taken not to specify reactive power capability that gives rise to voltage rise issues. For instance remote connection points benefit from more importing reactive power capability and not more exporting reactive power capability.				
Voltage Theme	Reactive Power Control Modes for PPMs	4.2.5.1	Article 21.3.d.(iii): Voltage Control Mode	37	t1 = time within which 90% of the change in reactive power is reached	1 – 5 sec	5	21.3.d.(iii)	C and D PGMs	1	parameter					Agree				
Voltage Theme	Reactive Power Control Modes for PPMs	4.2.5.1	Article 21.3.d.(iii): Voltage Control Mode	37	t2 = time within which 100% of the change in reactive power is reached	5 – 60 sec	5	21.3.d.(iv)	C and D PGMs	1	parameter					Agree				
Voltage Theme	Reactive Power Control Modes for PPMs	4.2.5.2	Article 21.3.d.(vi): Power Factor Control Mode	38	Target power factor	Not specified	site specific	21.3.d.(vi)	C and D PGMs	1	parameter					Agree				
Voltage Theme	Reactive Power Control Modes for PPMs	4.2.5.2	Article 21.3.d.(vi): Power Factor Control Mode	38	Time period to reach the set point	Not specified	site specific	21.3.d.(vi)	C and D PGMs	1	parameter					Do not disagree but time to reach target need not be site specific				
Voltage Theme	Reactive Power Control Modes for PPMs	4.2.5.2	Article 21.3.d.(vi): Power Factor Control Mode	38	Tolerance	Not specified	site specific	21.3.d.(vi)	C and D PGMs	1	parameter					Do not disagree but time to reach target need not be site specific				
Voltage Theme	Voltage Control System for SPGM	4.2.6.1	Article 19.2.a and 19.2.b.(ii)	39	Power Threshold	Not specified	All Type D PGMs	19.2.b.(ii)	D SPGMs	1	parameter					No comment				
Voltage Theme	Fault Ride Through Capability	4.2.5.1	Article 14.3.a & 16.3.a: FRT Capability for PGMs connected at voltage level <110 kV	40	Uret	0.05-0.3	0.05 p.u.	14.3.a & 16.3.a	B, C, D SPGMs	3	parameter					No comment	**Caterpillar Energy Solutions** - Considering the rotor angle stability of SPGMs, the upper limit 0.3 p.u. could be chosen. The active power operating point and under-excited operation affects the FRT performance. Voltage dips up to 0.3 p.u. for SPGMs have been successfully tested and is therefore recommended. **ENER-G** - the value of Uret is too low and tclear too long for synchronous machines to stay synchronised and so they run the risk of catastrophic damage. In reality they will not even pass any test designed to prove compliance. **AMPS** - Large companies manufacturing SPGM#s have the ability to develop bespoke combinations of prime-movers and alternators jointly controlled by a single encompassing regulator to form a special SPGM to meet the U.ret of 0.15%, but the end product is complex and costly. The consequence is that small compaines presently involved in SPGM OEM products will not have the necessary special equpment, technology and required development budgets. This will result in a loss of a competitive business base for type B SPGMs and therefore contary to the ENTSOe objective of acailitating a competitive energy market. AMSP remain resolved that a U.ret of 0.3pu for a duration of <150ms represents their experienced view of what is realistically available without loss os synchronisation for type B SPGM powered by an RIC engine where the total SPGM equipment will typically have an intertia in the region of 1.2s.	Comments related to the FRT parameters These values (and specifically the 5%Un) are compatible with installation of a generating unit in a prevalent grid, which for a unit of aprox 5-10 MW corresponds to a 100 MW grid (In fact FRT curves have been elaborated based on behaviour on prevalent grid). When Scc grid power becomes comparable with the power of the generating unit, strong voltage dip leads to obscillation/instability of the system frequency. However the 5% is associated more with transmission system (fault near a S/S). For distribution is in general recommended the adoption of 30% threshold. This data had been frequently used as base reference in several countries (based on correspondent studies). The calculation come as the typical value (possibly even higher) in case of fault on the main HV system. See also Elia (Belgium) studies on their system (to be comparable in term of extension to the irish one). --------------- Additional Note (added here since the chapter is discussed nowhere else) on Cogeneration/PGM embedded in industrial site. RfG art 6.3 states that PGM installed in industrial installation have the right to agree on different considtions for disconnecting from the grid to preserve the industrial process. RfG art 6.3 shall be taken in consideration and explicitly referred to in the next Grid Code. Industrial plants have specific needs to be preserved.		
Voltage Theme	Fault Ride Through Capability	4.2.5.1	Article 14.3.a & 16.3.a: FRT Capability for PGMs connected at voltage level <110 kV	40	Uclear	0.7-0.9	0.7 p.u.	14.3.a & 16.3.a	B, C, D SPGMs	3	parameter					No comment				
Voltage Theme	Fault Ride Through Capability	4.2.5.1	Article 14.3.a & 16.3.a: FRT Capability for PGMs connected at voltage level <110 kV	40	Urec1	Uclear	Uclear	14.3.a & 16.3.a	B, C, D SPGMs	3	parameter					No comment				
Voltage Theme	Fault Ride Through Capability	4.2.5.1	Article 14.3.a & 16.3.a: FRT Capability for PGMs connected at voltage level <110 kV	40	Urec2	0.85-0.9 & >=Uclear	0.9 p.u.	14.3.a & 16.3.a	B, C, D SPGMs	3	parameter					No comment				
Voltage Theme	Fault Ride Through Capability	4.2.5.1	Article 14.3.a & 16.3.a: FRT Capability for PGMs connected at voltage level <110 kV	40	tclear	0.14-0.25	150 ms	14.3.a & 16.3.a	B, C, D SPGMs	3	parameter					No comment				
Voltage Theme	Fault Ride Through Capability	4.2.5.1	Article 14.3.a & 16.3.a: FRT Capability for PGMs connected at voltage level <110 kV	40	trec1	tclear	tclear	14.3.a & 16.3.a	B, C, D SPGMs	3	parameter					No comment				
Voltage Theme	Fault Ride Through Capability	4.2.5.1	Article 14.3.a & 16.3.a: FRT Capability for PGMs connected at voltage level <110 kV	40	trec2	trec1-0.7	450 ms	14.3.a & 16.3.a	B, C, D SPGMs	3	parameter					No comment				
Voltage Theme	Fault Ride Through Capability	4.2.5.1	Article 14.3.a & 16.3.a: FRT Capability for PGMs connected at voltage level <110 kV	40	trec3	trec2-1.5	trec2	14.3.a & 16.3.a	B, C, D SPGMs	3	parameter					No comment				
Voltage Theme	Fault Ride Through Capability	4.2.5.1	Article 14.3.a & 16.3.a: FRT Capability for PGMs connected at voltage level <110 kV	41	Uret	0.05-0.15	0.15 p.u.	14.3.a & 16.3.a	B, C, D PPMs & offshore PPMs	3	parameter					Agree- within RfG range				To be confirmed with WTG OEM's
Voltage Theme	Fault Ride Through Capability	4.2.5.1	Article 14.3.a & 16.3.a: FRT Capability for PGMs connected at voltage level <110 kV	41	Uclear	Uret -0.15	Uret	14.3.a & 16.3.a	B, C, D PPMs & offshore PPMs	3	parameter					Agree- within RfG range				
Voltage Theme	Fault Ride Through Capability	4.2.5.1	Article 14.3.a & 16.3.a: FRT Capability for PGMs connected at voltage level <110 kV	41	Urec1	Uclear	Uclear	14.3.a & 16.3.a	B, C, D PPMs & offshore PPMs	3	parameter					Agree- within RfG range				To be confirmed with WTG OEM's
Voltage Theme	Fault Ride Through Capability	4.2.5.1	Article 14.3.a & 16.3.a: FRT Capability for PGMs connected at voltage level <110 kV	41	Urec2	0.85	0.85 p.u.	14.3.a & 16.3.a	B, C, D PPMs & offshore PPMs	3	parameter					Agree- within RfG range				To be confirmed with WTG OEM's
Voltage Theme	Fault Ride Through Capability	4.2.5.1	Article 14.3.a & 16.3.a: FRT Capability for PGMs connected at voltage level <110 kV	41	tclear	0.14-0.25	250 ms	14.3.a & 16.3.a	B, C, D PPMs & offshore PPMs	3	parameter					Agree- within RfG range				To be confirmed with WTG OEM's
Voltage Theme	Fault Ride Through Capability	4.2.5.1	Article 14.3.a & 16.3.a: FRT Capability for PGMs connected at voltage level <110 kV	41	trec1	tclear	tclear	14.3.a & 16.3.a	B, C, D PPMs & offshore PPMs	3	parameter					Agree- within RfG range				To be confirmed with WTG OEM's
Voltage Theme	Fault Ride Through Capability	4.2.5.1	Article 14.3.a & 16.3.a: FRT Capability for PGMs connected at voltage level <110 kV	41	trec2	trec1	trec1	14.3.a & 16.3.a	B, C, D PPMs & offshore PPMs	3	parameter					Agree- within RfG range				
Voltage Theme	Fault Ride Through Capability	4.2.5.1	Article 14.3.a & 16.3.a: FRT Capability for PGMs connected at voltage level <110 kV	41	trec3	1.5-3.0	2.9 s	14.3.a & 16.3.a	B, C, D PPMs & offshore PPMs	3	parameter					Agree- within RfG range				To be confirmed with WTG OEM's

Voltage Theme	**Fault Ride Through Capability**	4.2.5.2	Article 16.3.a FRT Capability for PGMs connected at voltage level ³110 kV	42	Uret	0	0	16.3.a	D SPGMs	3	parameter	In the consultation document, the voltage against time profile refers to phase voltages on the network voltage level at the connection point during a symmetrical fault, as a function of time before, during and after the fault. Fault Ride through Studies also look at unbalanced fault. does this mean that this profile apply only to symmetrical fault?				Agree- within RfG range		Comments related to the FRT parameters: These values (and specifically the 150ms, 450ms) is compatible with installation of a generating unit in a prevalent grid, which for a unit of aprox 5-10 MW corresponds to a 100 MW grid (in fact FRT curves have been elaborated based on behaviour on prevalent grid). When the grid power becomes comparable with the power of the generating unit, strong voltage dip leads to oscillations/instability of the system frequency. Additional Note (added here since the chapter is discussed nowhere else) on Cogeneration/PGM embedded in industrial site. RfG art 6.3 states that PGM installed in industrial installation have the right to agree on different conditions for disconnecting from the grid to preserve the industrial process. RfG art 6.3 shall be taken in consideration and explicitly referred to in the next Grid Code; industrial plants have specific needs to be preserved.		
Voltage Theme	**Fault Ride Through Capability**	4.2.5.2	Article 16.3.a FRT Capability for PGMs connected at voltage level ³110 kV	42	Uclear	0.25	0.25 p.u.	16.3.a	D SPGMs	3	parameter					Agree- within RfG range				
Voltage Theme	**Fault Ride Through Capability**	4.2.5.2	Article 16.3.a FRT Capability for PGMs connected at voltage level ³110 kV	42	Urec1	0.5-0.7	0.5 p.u.	16.3.a	D SPGMs	3	parameter					Agree- within RfG range				
Voltage Theme	**Fault Ride Through Capability**	4.2.5.2	Article 16.3.a FRT Capability for PGMs connected at voltage level ³110 kV	42	Urec2	0.85-0.9	0.9 p.u.	16.3.a	D SPGMs	3	parameter					Agree- within RfG range				
Voltage Theme	**Fault Ride Through Capability**	4.2.5.2	Article 16.3.a FRT Capability for PGMs connected at voltage level ³110 kV	42	tclear	0.14-0.25	150 ms	16.3.a	D SPGMs	3	parameter					Agree- within RfG range				
Voltage Theme	**Fault Ride Through Capability**	4.2.5.2	Article 16.3.a FRT Capability for PGMs connected at voltage level ³110 kV	42	trec1	tclear -0.45	450 ms	16.3.a	D SPGMs	3	parameter					Agree- within RfG range				
Voltage Theme	**Fault Ride Through Capability**	4.2.5.2	Article 16.3.a FRT Capability for PGMs connected at voltage level ³110 kV	42	trec2	trec1-0.7	450 ms	16.3.a	D SPGMs	3	parameter					Agree- within RfG range				
Voltage Theme	**Fault Ride Through Capability**	4.2.5.2	Article 16.3.a FRT Capability for PGMs connected at voltage level ³110 kV	42	trec3	trec2-1.5	450 ms	16.3.a	D SPGMs	3	parameter					Agree- within RfG range				
Voltage Theme	**Fault Ride Through Capability**	4.2.5.2	Article 16.3.a FRT Capability for PGMs connected at voltage level ³110 kV	43	Uret	0	0	16.3.a	D PPMs & offshore PPMs	1	parameter	Same as row 138		Converter based generation may have difficulties meeting the required proportional current injection levels for such low values of voltage as this may cause converter instability. Propose to limit the voltage level to 0.15pu where the units are required to inject P and Q.		Agree- as per RfG				
Voltage Theme	**Fault Ride Through Capability**	4.2.5.2	Article 16.3.a FRT Capability for PGMs connected at voltage level ³110 kV	43	Uclear	Uret	Uret	16.3.a	D PPMs & offshore PPMs	1	parameter					Agree- as per RfG				
Voltage Theme	**Fault Ride Through Capability**	4.2.5.2	Article 16.3.a FRT Capability for PGMs connected at voltage level ³110 kV	43	Urec1	Uclear	Uclear	16.3.a	D PPMs & offshore PPMs	1	parameter					Agree- as per RfG				
Voltage Theme	**Fault Ride Through Capability**	4.2.5.2	Article 16.3.a FRT Capability for PGMs connected at voltage level ³110 kV	43	Urec2	0.85	0.85 p.u.	16.3.a	D PPMs & offshore PPMs	1	parameter					Agree- as per RfG				
Voltage Theme	**Fault Ride Through Capability**	4.2.5.2	Article 16.3.a FRT Capability for PGMs connected at voltage level ³110 kV	43	tclear	0.14-0.25	150 ms	16.3.a	D PPMs & offshore PPMs	1	parameter					Agree- as per RfG				
Voltage Theme	**Fault Ride Through Capability**	4.2.5.2	Article 16.3.a FRT Capability for PGMs connected at voltage level ³110 kV	43	trec1	tclear	tclear	16.3.a	D PPMs & offshore PPMs	1	parameter					Agree- as per RfG				
Voltage Theme	**Fault Ride Through Capability**	4.2.5.2	Article 16.3.a FRT Capability for PGMs connected at voltage level ³110 kV	43	trec2	trec1	trec1	16.3.a	D PPMs & offshore PPMs	1	parameter					Agree- as per RfG				
Voltage Theme	**Fault Ride Through Capability**	4.2.5.2	Article 16.3.a FRT Capability for PGMs connected at voltage level ³110 kV	43	trec3	1.5-3.0	2.9 s	16.3.a	D PPMs & offshore PPMs	1	parameter					Agree- as per RfG				
Voltage Theme	**Fault Ride Through Capability**	4.2.5.3.1	Article 20.2.b Fast Fault Current Injection for Symmetrical Faults	44	Voltage threshold for fast fault current injection	Not specified	During voltage dips i.e. when the voltage is below 0.9 p.u.	20.2.b	B, C and D PPMs	1	parameter					Agree				
Voltage Theme	**Fault Ride Through Capability**	4.2.5.3.1	Article 20.2.b Fast Fault Current Injection for Symmetrical Faults	44	End of the voltage deviation	Not specified	Once the voltage has recovered to within normal operating voltage range	20.2.b	B, C and D PPMs	1	parameter					More clarity required. There is a need to explicitly 'specify what "normal operating voltage range"' is.				
Voltage Theme	**Fault Ride Through Capability**	4.2.5.3.1	Article 20.2.b Fast Fault Current Injection for Symmetrical Faults	44	the characteristics of the fast fault current, including the time domain for measuring the voltage deviation and fast fault current	Not specified	Reactive current should be provided for the duration of the voltage deviation within the rating of the PPM	20.2.b	B, C and D PPMs	1	parameter					Agree				
Voltage Theme	**Fault Ride Through Capability**	4.2.5.3.1	Article 20.2.b Fast Fault Current Injection for Symmetrical Faults	44	the timing and accuracy of the fast fault current, which may include several stages during a fault and after its clearance	Not specified	Rise Time no greater than 100ms and a Settling Time no greater than 300ms.	20.2.b	B, C and D PPMs	2	parameter					Has this been discussed and agreed with DSOs?				
Voltage Theme	**Fault Ride Through Capability**	4.2.5.3.2	Article 20.2.c Fast Fault Current Injection for Asymmetrical Faults	45	Voltage threshold for fast fault current injection	Not specified	During voltage dips i.e. when the voltage is below 0.9 p.u.	20.2.b	B, C and D PPMs	1	parameter					Agree				
Voltage Theme	**Fault Ride Through Capability**	4.2.5.3.2	Article 20.2.c Fast Fault Current Injection for Asymmetrical Faults	45	the characteristics of the fast fault current, including the time domain for measuring the voltage deviation and fast fault current	Not specified	Reactive current should be provided for the duration of the voltage deviation within the rating of the PPM	20.2.b	B, C and D PPMs	1	parameter					Agree				To be confirmed with WTG OEM's
Voltage Theme	**Fault Ride Through Capability**	4.2.5.3.2	Article 20.2.c Fast Fault Current Injection for Asymmetrical Faults	45	the timing and accuracy of the fast fault current, which may include several stages during a fault and after its clearance	Not specified	Rise Time no greater than 100ms and a Settling Time no greater than 300ms.	20.2.b	B, C and D PPMs	2	parameter					Has this been discussed and agreed with DSOs?				
Voltage Theme	**Fault Ride Through Capability**	4.2.5.4	Article 20.3.a Post-Fault Active Power Recovery for PPMs	46	when the post-fault active power recovery begins, based on a voltage criterion	Not specified	un< 0.9 p.u.	20.3.a	B, C and D PPMs & offshore PPMs	1	parameter					Agree				
Voltage Theme	**Fault Ride Through Capability**	4.2.5.4	Article 20.3.a Post-Fault Active Power Recovery for PPMs	46	maximum allowed time for active power recovery	Not specified	500ms/1s	20.3.a	B, C and D PPMs & offshore PPMs	1	parameter					Agree				
Voltage Theme	**Fault Ride Through Capability**	4.2.5.4	Article 20.3.a Post-Fault Active Power Recovery for PPMs	46	magnitude and accuracy for active power recovery	Not specified	90%	20.3.a	B, C and D PPMs & offshore PPMs	1	parameter					Agree noting that this should be 90% of the Power Available rather than necessarily of the pre disturbance power level (as power available/wind may have decreased during the disturbance for PPMs with fluctuating resources)				
Voltage Theme	**Fault Ride Through Capability**	4.2.5.5	Article 21.3.e Priority Given to Active or Reactive Power Contribution for PPMs	47	Prioritisation requirements during FRT	Active/Reactive	Active	21.3.e	C and D PPMs	3	parameter					Agree - it is up to the Network Operator to choose what to prioritise				
Voltage Theme	**Non-Mandatory Voltage Theme Requirements that we are not invoking at this time**	4.2.6	Non-Mandatory Voltage Theme Requirements that we are not invoking at this time	48	Simultaneous overvoltage and underfrequency or simultaneous undervoltage and overfrequency	Do we want to expertise the right to specify this non-mandatory RfG?	Not invoking	16(02)(a)(ii)	Type A, B, C and D PGMs		requirement					Agree				Noted
System Restoration Theme	**Operation following Tripping to House Load**	4.3.1	Article 15.5.c.(iii) Operation following tripping to house load	49	Operation Following Tripping to House Load	Not Specified	4 hours	15.5.c.iii	C and D PGMs with a minimum re-synchronisation time greater than 15 minutes*	3	parameter	We understand that faster synchronising units (< 15 min) do not fall into this requirement. Units with less than 15min re-synchronisation time are not required to have 4hours operation time on house load.				No comment	**GE Distributed Power** - It is stated that this requirement applies to units which have a re-synchronisation time greater than 15 minutes; does this mean that units with lower synchronisation times MUST not comply? If we need comply, can we change the time from 4 hours to 2 hours?			
Protection and Instrumentation Theme	**Manual, local measures where the automatic remote devices are out of service**	4.4.1	Article 15.2.b: Manual, local measures where the automatic remote devices are out of service	50	Time required to achieve setpoint when automatic remote devices are unavailable	Not Specified	1 hour	15(2)(b)	B, C and D PGMs	3	parameter					Agree		The main issue here is junit. 1h can be a target value.		Timeline of 1 hour to allow operator attend PGM site will be difficult to achieve
Protection and Instrumentation Theme	**Instrumentation: Quality of Supplies**	4.4.2	Article 15.6.b (i): Instrumentation: Quality of Supplies	51	Quality of supplies parameters to be recorded.	Not Specified	Site Specific	15(6)(b)(i)	C and D PGMs & offshore PPMs	1	requirement					Agree - in line with practice -site specific case by case basis justified on the basis of wide variety of plant				
Protection and Instrumentation Theme	**Dynamic System Behaviour Monitoring**	4.4.3	Article 15.6.b.(iii): Dynamic System Behaviour Monitoring	52	oscillation trigger detecting poorly damped power oscillations.	Not Specified	Site Specific	15(6)(b)(iii)	C and D PGMs & offshore PPMs	1	parameter					Agree - in line with practice -site specific case by case basis justified on the basis of wide variety of plant				
Protection and Instrumentation Theme	**Simulation Model Provision**	4.4.4	Article 15.6.c.(iii) Simulation Model Provision	53	Model Provision	Not Specified	Retain the existing model provision requirements with the inclusion of min and max short circuit levels as part of Grid Code Planning Code Appendix Generator Data Requirements	15(6)(c)(iii)	C and D PGMs & offshore PPMs	2	requirement	The actual Grid Code shall provide more information about excitation and turbine governor model for PGMs that are not in the IEEE standard block diagram. It says that other model shall be agreed with the TSO. Would block diagrams, description and parameters be sufficient? How detailed the model should be, for which type of study and how IP is protected?				Agree	**GE Distributed Power** - We can supply simplified block diagrams from both the AVR and Engine, but they cannot be used for EMT or RMS simulations; in that case, a locked model in Power Factory format could be provided (due to IP restrictions). Will this be an issue?	For synchronous genera[illegible]me from generator data sheet and AVR limits, already part of the present documentation request.		
Protection and Instrumentation Theme	**Neutral-point at the network side of step transformers**	4.4.5	Article 15.6.f.: Neutral-point at the network side of step transformers	54	Earthing arrangement of the neutral-point	Not Specified	400 kV – solidly earthed 220 kV – site specific 110 kV – site specific	15(6)(f)	C and D PGMs & offshore PPMs	1	parameter					Agree - in line with current practice				
Protection and Instrumentation Theme	**Non-Mandatory Protection Theme Requirements that are not for consultation but will be agreed on a case by case basis**	4.4.6	Non-Mandatory Protection Theme Requirements that are not for consultation but will be agreed on a case by case basis	55	Control Scheme and Settings: Agreement and coordination between the TSO, the RSO (TSO and DSO) and the power generating facility owner (PGFO)	Control schemes and settings of the control devices	Case by case basis	14.5.a	B,C,D PGMs & offshore PPMs	N/A	parameter					Agree				
Protection and Instrumentation Theme	**Non-Mandatory Protection Theme Requirements that are not for consultation but will be agreed on a case by case basis**	4.4.6	Non-Mandatory Protection Theme Requirements that are not for consultation but will be agreed on a case by case basis	55	Electrical Protection Schemes and settings: Agreement and coordination between the RSO and the PGFO	Protection schemes and settings	Case by case basis	14.5.b	B,C,D PGMs & offshore PPMs	N/A	parameter					Agree				
Protection and Instrumentation Theme	**Non-Mandatory Protection Theme Requirements that are not for consultation but will be agreed on a case by case basis**	4.4.6	Non-Mandatory Protection Theme Requirements that are not for consultation but will be agreed on a case by case basis	55	Loss of angular stability or loss of control: Agreement between PGFO and the RSO (DSO or TSO), in coordination with the TSO	Criteria to detect loss of angular stability or loss of control	Case by case basis	15.6.a	C.D PGM & Offshore PPMs	N/A	parameter					Agree				
Protection and Instrumentation Theme	**Non-Mandatory Protection Theme Requirements that are not for consultation but will be agreed on a case by case basis**	4.4.6	Non-Mandatory Protection Theme Requirements that are not for consultation but will be agreed on a case by case basis	55	Instrumentation: Settings of the fault recording equipment, including triggering criteria and sampling rate	Settings of the fault recording equipment, including triggering criteria and sampling rate	Case by case basis	15.6.b(ii)	C.D PGM & Offshore PPMs	N/A	parameter					Agree				
Protection and Instrumentation Theme	**Non-Mandatory Protection Theme Requirements that are not for consultation but will be agreed on a case by case basis**	4.4.6	Non-Mandatory Protection Theme Requirements that are not for consultation but will be agreed on a case by case basis	55	Agreement between the PGFO and the RSO (DSO or TSO), in coordination with the TSO.		Case by case basis	15.6.b(ii)	C.D PGM & Offshore PPMs	N/A	parameter					Agree				
Protection and Instrumentation Theme	**Non-Mandatory Protection Theme Requirements that are not for consultation but will be agreed on a case by case basis**	4.4.6	Non-Mandatory Protection Theme Requirements that are not for consultation but will be agreed on a case by case basis	55	Instrumentation: Protocols for recorded data	Protocols for recorded data	Case by case basis	15.6.b(iv)	C.D PGM & Offshore PPMs	N/A	parameter					Agree				
Protection and Instrumentation Theme	**Non-Mandatory Protection Theme Requirements that are not for consultation but will be agreed on a case by case basis**	4.4.6	Non-Mandatory Protection Theme Requirements that are not for consultation but will be agreed on a case by case basis	55	Agreement between PGFO, the RSO and the relevant TSO		Case by case basis	15.6.b(iv)	C.D PGM & Offshore PPMs	N/A	parameter					Agree				
Protection and Instrumentation Theme	**Non-Mandatory Protection Theme Requirements that are not for consultation but will be agreed on a case by case basis**	4.4.6	Non-Mandatory Protection Theme Requirements that are not for consultation but will be agreed on a case by case basis	55	Installation of devices for system operations and system security: Agreement between RSO or TSO and PGFO	Definition of the devices needed for system operation and system security	Case by case basis	15.6.d	C.D PGM & Offshore PPMs	N/A	parameter					Agree				
Protection and Instrumentation Theme	**Non-Mandatory Protection Theme Requirements that are not for consultation but will be agreed on a case by case basis**	4.4.6	Non-Mandatory Protection Theme Requirements that are not for consultation but will be agreed on a case by case basis	55	Synchronisation: Agreement between the RSO and the PGFO	Settings of the synchronisation devices	Case by case basis	16.4	D PGM & offshore PPMs	N/A	parameter					Agree				
Protection and Instrumentation Theme	**Non-Mandatory Protection Theme Requirements that are not for consultation but will be agreed on a case by case basis**	4.4.6	Non-Mandatory Protection Theme Requirements that are not for consultation but will be agreed on a case by case basis	55	Angular stability under fault conditions: Agreement between the TSO and PGFO	Agreement for technical capabilities of the power generating module to aid angular stability.	Case by case basis	19.3	D SPGM	N/A	parameter					Agree				