SONI and NIE 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 SONI and NIE 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 SONI Ltd, in its role as the Transmission System Operator in Northern Ireland (hereafter referred to as the TSO) and Northern Ireland Electricity Networks in their role as the Distribution System Operator in Northern Ireland (hereafter referred to as the DSO). References in this document to the Relevant System Operator (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 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 Northern 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 Northern 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 Utility Regulator (Utility Regulator) 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 Utility Regulator. 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 Utility Regulator 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.

EirGrid plc in its role as the Transmission System Operator in Ireland and by ESB Networks in its role as the Distribution System Operator in Ireland are submitting an equivalent proposal document to the Commission for Regulation of Utilities.

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 Northern Ireland[5], RfG Banding Threshold Consultation Minded to Position in Northern Ireland[6] and the RfG Banding Threshold Consultation Final Position in Northern 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, either TSO or DSO as relevant, on each parameter 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 & Fault Ride Through
3. System Restoration
4. Protection & Instrumentation

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[5] http://www.soni.ltd.uk/media/documents/Consultations/RfG Banding_Thresholds_Consultation_Northern_Ireland.pdf

[6] http://www.soni.ltd.uk/InformationCentre/Publications/

[7] http://www.soni.ltd.uk/InformationCentre/Publications/

2. Scope

The scope of this document is to seek approval from the National Regulatory Authority on SONI and NIE 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 of 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.

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

As mandatory and exhaustive parameters are not at the discretion of the RSO to modify they do not form part of this submission.

3.1. Principles underpinning the Proposals

Many of the requirements for general application exist in Northern 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.

Non-Mandatory Requirement Selection

In the majority of cases the following assumptions are made:

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

Non-Exhaustive Parameter Selection

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

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

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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 Northern 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 Northern 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 Northern 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 Northern 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 TSO's **Final Position on Banding Threshold** proposes the following:

- Type A units range from 800 W up to $0.0\dot{9}$ MW
- Type B units range from 0.1MW up to $4.\dot{9}$ MW
- Type C units range from 5 MW to $9.\dot{9}$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 'P_{max}' 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:

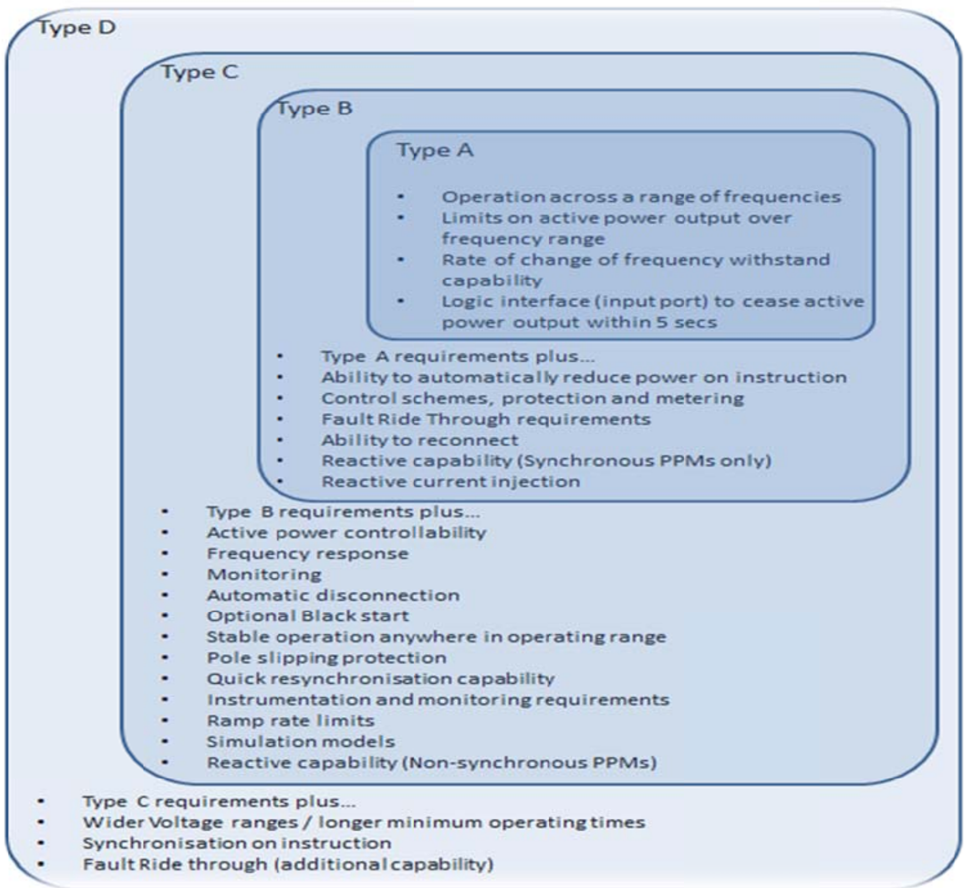
- Synchronous PGMs (SPGMs)
- Power Park Modules (PPMs)
- Offshore PPMs

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.



4. Consultation Update

SONI and NIE 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.

4.1. Summary of Submissions

The TSO received 5 individual submissions on the consultation of which 5 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 SONI 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.

One 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 two 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 3	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 a 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
5.1.4.7	Table 14	Active power range	10%	SPGMs: 10% PPMs: 60% in 5 seconds and 100% in 15 seconds

4.3. Derogation Requests and Proposed Changes

There are two 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

There has been engagement with the Utility Regulator on these two 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 (**Error! Reference source not found.**)*

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 **Error! Reference source not found.** 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 the Utility Regulator to capture this error.

To this end, the TSO have not proposed a value for this parameter in **Error! Reference source not found.** 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 (**Error! Reference source not found.**)*

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 TSO is submitting a derogation request to the Utility Regulator in order to maintain the existing Grid Code requirements for Frequency response of PPMs.

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 to 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 the 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/or 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, as 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 consultation. The other parameters are provided for context.

Proposal

Parameter	Parameter in RfG	Consultation 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 1 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 Northern 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 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. The TSO 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 Responses

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 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 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. The TSO 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 that this proposal is an increase from the 60 minute requirement in the Grid Code today. They also stated that they would confirm with the WTG OEM's.

SO Comment

This comment is noted, however, the TSO has selected the minimum time in the range allowed under the RfG.

Submission 3

Another respondent commented that this proposal is an increase from the 60 minute requirement in the Grid Code today. They further noted that they are concerned that the TSO may attempt to change the current Grid Code standard in advance of the Network Codes coming into force and thus skip the need for a CBA. They commented that this previously happened with RoCoF leaving the existing generators with significant costs and little recompense through any other revenue stream.

SO Comments

The TSO will apply the requirements of RfG Network Code, which will then result in modifications to Grid Code and will come into force as specified in the RfG Network Code (Article 4). For clarity the new RfG Network Code requirements will apply to PGM facility owners who have concluded a final and binding contract for the purchase of their main plant generators after 17th May 2018. The TSO does not intend to introduce these RfG Network Code modifications into Grid Code in advance of the RfG Network Code requirements coming into force to avoid the provisions in Article 4.3

Submission 4

One respondent commented that the wider frequency ranges are not in line with RfG Article 13.1. They comment that wider ranges are only allowed in agreement with the power plant owner.

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 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 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. The TSO 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 5

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 the RfG does not foresee them.

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 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 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. The TSO 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.

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	Consultation 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 and Offshore PPMs	1
The proposal for loss of mains protection	Not Specified	1 Hz/Sec with a 500ms delay.	13.1.b	A, B, C and D and Offshore PPMs	1

Table 2 Rate-of-change-of-frequency-type loss of mains protection & withstand capability

Justification

The proposal is to maintain the ‘agreed in principle’ Grid Code standard for RoCoF (df/dt) of 1 Hz/ sec over a 500 ms rolling window. It is proposed to review the RoCoF requirement of 1 Hz/ sec as part of the 3 year review in 2021.

Consultation Responses

Submission 1

One respondent commented that there are existing PGM's non-compliant with the current Grid Code RoCoF Modification because the existing standards were changed without proper investigation prior to having the RA approval. They further commented that this process did not follow the CBA set out in the Network Code and has not provided generators with an appropriate revenue stream for this work.

SO Comments

Changes to RoCoF requirements were developed through the DS3 programme. These consultation and proposal documents utilise the RoCoF parameters as included in the approved in principle modifications to the Grid Code. This comment lies outside the scope of this proposal document as this document is dealing specifically with the RfG Network Code implementation which postdates the RoCoF decision.

The requirement for CBA analysis etc. as specified in Article 4.3 is applicable to new plant who have concluded a final and binding contract for the purchase of their main plant generators after 17th May 2018.

Submission 2

One respondent commented that RoCoF measurements depend on the measurement duration. They query what measurement window is used for RoCoF loss of main protection.

SO Comments

This is a minimum standard for protection that is aimed at ensuring loss of mains protection does not disconnect a PGM for a RoCoF event less than 1Hz/s over 500ms. It is our understanding that due to the operation of RoCoF relays, averaging over a 500ms timeframe is not possible. Therefore this setting is an attempt to translate the requirement into something that can be implemented in a relay.

Submission 3

One respondent commented that frequency requirements should be on an equality principle. They recommend that the parameters in Ireland and Northern Ireland be harmonized.

SO Comments

The TSO accepts the equality principle with respect to this RfG Network Code parameter. In both jurisdictions, the proposal is to apply the approved in principle RoCoF standard of 1Hz/s over a 500ms window. The All Island DS3 programme recommended to apply this standard in the Ireland and Northern Ireland single synchronous area. The process for updating this parameter including significant consultation with industry.

It is worth noting that the harmonisation of the two existing Grid Codes 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 4

One respondent commented that the term loss of mains in a Transmission context needs to be defined further.

SO Comments

Whilst loss-of-main protection is not currently in use on the Transmission System, the proposal is in alignment with the agreed in principle Grid Code modification on RoCoF withstand capability.

If or when, it is decided to implement loss-of-mains protection on the Transmission system, details regarding the context of its use will be made available.

Submission 5

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 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 approved in principle Grid Code modifications requirements 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.

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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.

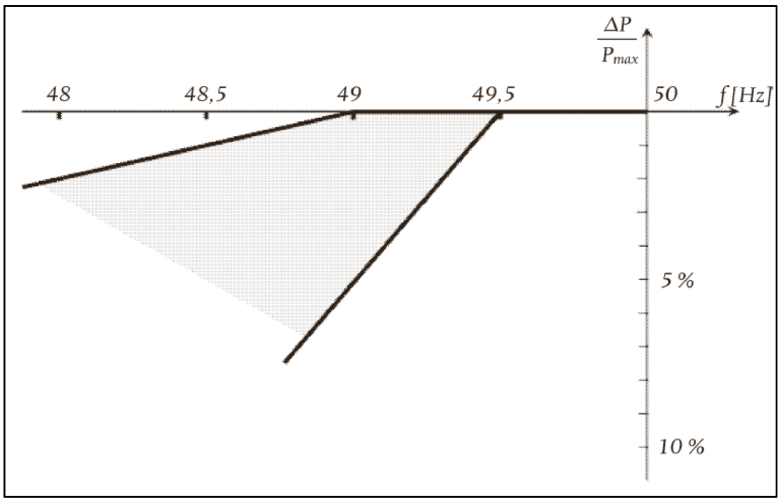


Figure 1 Maximum Power Capability Reduction with Falling Frequency

Proposal

Parameter	Parameter in RfG	Consultation Proposal	Article Number	Type Applicability	Justification Code
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 3 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.

It is acknowledged that this proposal does not align with the current Grid Code requirements and is an increased requirement on PGMs. However by increasing the requirement here, we are able to lessen any further reduction in the system frequency by minimising the reduction in the generation MW output. This 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”.

It is acknowledged that this proposal does not align with the current Grid Code requirements and is an increased requirement on PGMs. However by increasing the requirement here, we are able to lessen any further reduction in the system frequency by minimising the reduction in the generation MW output. This allows time for frequency response measures to be activated and ultimately the system frequency to stabilise.

Consultation Responses

Submission 1

One respondent 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%Pn/Hz or 10%Pn/Hz. They also referenced the ENTSO-E IGD document on Maximum admissible active power reduction at low frequency from 49.5 Hz for the steady state.

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 IGD. On page 7 section 2 it states it would make sense to have different requirements for different synchronous areas, for example the UK, IE = 2%/Hz. At frequencies above 49.5Hz a drop in active power output is not permitted. This is a change as compared to the consultation proposal of 49Hz. Having considered the consultee's comments regarding capability under steady state conditions The TSO believes no power reduction above 49.5Hz to be reasonable for SPGM Gas Turbines and in alignment with the ENTSO-E IGD's recommendation regarding steady state response. However The TSO would expect SPGM Gas Turbines performance to be better than this in the transient time frame (see table on page 7 of ENTSO-E IGD up to 30secs)

Submission 2

One respondent commented that existing PGM's are not compliant with this as they met the System requirements in the past. They comment that any requirement to comply with this would require an OEM investigation and investment that would be subject to the CBA procedure outlined in this Network Code. They further comment that they are concerned that the TSO may attempt to have this changed in the current Grid Code prior to the Network Code coming into force, and so skip the requirement for a CBA. They comment that this previously happened with RoCoF leaving the existing generators with huge bills and little recompense through any other revenue stream.

SO Comments

The TSO will apply the requirements of RfG Network Code, which will then result in modifications to Grid Code and will come into force as specified in the RfG Network Code (Article 4). For clarity the new RfG Network Code requirements will apply to power-generating facility owners who have concluded a final and binding contract for the purchase of their main plant generators after 17th May 2018. The TSO does not intend to introduce these RfG Network Code modifications into Grid Code in advance of the RfG Network Code requirements coming into force to avoid the provisions in Article 4.3

Submission 3

One respondent commented that only the inherent behaviour of a generating unit is relevant for system stability. They commented that any control actions during a frequency transient, to compensate for the inherent power loss, will be too late or might further disturb the system e.g. when frequency is stabilised. They suggest that any requirement which does not consider the inherent behaviour would therefore exclude this technology from access to the system, disregarding all other benefits of this technology. For Synchronous PGMs it has to be taken into account that during a frequency drop (i.e. when the requirement is important) the inertia power response compensates the inherent power reduction to a certain amount (depending on the RoCoF). They further commented that compliance with this requirement is only for certain technologies only possible under certain ambient conditions – due to the fact that they show a strong relation between inherent power loss and ambient temperature. Hence, it does not make sense to link the requirement to a fixed ambient temperature. Furthermore a real test of compliance is not possible. Therefore, only a manufacturer statement based on calculations and simulations can be used as a proof of compliance.

They have proposed an alternative approach for this parameter:

- Require from SPGMs on a project-specific basis the inherent power vs. frequency characteristics (without any power compensation control measures) with ambient temperature as a variable parameter, to be used for system stability studies and design. This calculation can be done e.g. for a defined frequency over time curve"

SO Comments

Your comments are noted. The ENTSO-E IGD document for national implementation for network codes on grid connection entitled "Maximum Admissible active power reduction at low frequencies" deals with system characteristics and the RfG Network Code requirements in order to support system frequency stability. This includes support in transient and steady state time domains when the frequency is stabilised. The proposed threshold frequency and slope chosen reflect the system characteristics of IE and the UK.

Considering technology characteristics in particular for SPGM Gas Turbines this is also discussed in the ENTSO-E IGD. The changes in performance can be mitigated depending on machine type and configuration. In May and June 2017 ENTSO-E conducted a consultation of European stakeholders to collect the most up to date information

The reduction rate of 2% of the maximum capacity at 50 Hz per 1 Hz frequency drop is in alignment with the ENTSO-E IGD. On page 7 section 2 it states it would make sense to have different requirements for different synchronous areas for example the UK, IE = 2%/Hz. At frequencies above 49.5Hz a drop in active power output is not permitted. This is a change as compared to the consultation proposal of 49Hz. Having considered the consultees' comments regarding capability under steady state conditions The TSO believes no power reduction above 49.5Hz to be reasonable for SPGM CCGT'S and in alignment with the ENTSO-E IGD's recommendation regarding steady state response. However The TSO would expect CCGT performance to be better than this in the transient time frame (see table on page 7 of ENTSO-E IGD up to 30secs)

As per the ENTSO-E IGD the PGM should provide the characteristics expected over a full temperature range (eg-10ºC - 40ºC). The performance specified under Article 13.5 is at 10ºC

Submission 4

One respondent commented that a gas turbine technology output at falling frequency is non-linear nor can it 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

Your comments are noted. The ENTSO-E guidance document for national implementation for network codes on grid connection entitled "Maximum Admissible active power reduction at low frequencies" deals with system characteristics and the RfG Network Code requirements in order to support system frequency stability. This includes support in transient and steady state time domains when the frequency is stabilised. The proposed threshold frequency and slope chosen reflect the system characteristics of IE and the UK.

Considering technology characteristics in particular for SPGM CCGT's this is also discussed in the ENTSO-E IGD. The changes in performance can be mitigated depending on machine type and configuration. In May and June 2017 ENTSO-E conducted a consultation of European stakeholders to collect the most up to date information

The reduction rate of 2% of the maximum capacity at 50 Hz per 1 Hz frequency drop is in alignment with the ENTSO-E IGD. On page 7 section 2 it states it would make sense to have different requirements for different synchronous areas for example UK, IE = 2%/Hz. At frequencies above 49.5Hz a drop in active power output is not permitted. This is a change as compared to the consultation proposal of 49Hz. Having considered consultees comments regarding capability under steady state conditions The TSO believes no power reduction above 49.5Hz to be reasonable for SPGM Gas Turbines and in alignment with the ENTSO-E IGD's recommendation regarding steady state response. However The TSO would expect CCGT performance to be better than this in the transient time frame (see table on page 7 of ENTSO-E IGD up to 30secs)

As per the ENTSO-E IGD the PGM should provide the characteristics expected over a full temperature range (eg-10ºC - 40ºC). The performance specified under Article 13.5 is at 10ºC

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	Consultation Proposal	Article Number	Type Applicability	Justification Code
Ambient Conditions	Not Specified	10°C, 70% relative humidity and 1013 hPa for gas fired turbine generators	13.5	Gas Turbine Generator SPGMs (A, B, C and D).	3

Table 4 Admissible active power reduction from maximum output

Justification

The RfG allows the TSO to specify the applicable ambient conditions. It is proposed to use10°C, 70 % relative humidity and 1013 hPa. The ENTSO-E guidance document for national implementation for network codes on grid connection (Implementation Guidelines Documents) highlights that the need for this requirement and is driven by the characteristics of gas turbine generators. 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 turbine generator units.

Consultation Responses

Submission 1

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

SO Comments

As per the ENTSO-E IGD "Maximum Admissible active power reduction at low frequencies" 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 existing PGM's are not compliant with this as they met the system requirements in the past. They comment that any requirement to comply with this would require an OEM investigation and investment that would be subject to the CBA procedure outlined in this Network Code. They further comment that they are concerned that the TSO may attempt to have this changed in the current Grid Code prior to the Network Code coming into force, and so skip the requirement for a CBA. They comment that this previously happened with RoCoF leaving the existing generators with huge bills and little recompense through any other revenue stream.

SO Comments

The TSO will apply the requirements of RfG Network Code, which will then result in modifications to Grid Code and will come into force as specified in the RfG Network Code (Article 4). For clarity the new RfG Network Code requirements will apply to power-generating facility owners who have concluded a final and binding contract for the purchase of their main plant generators after 17th May 2018. The TSO does not intend to introduce these RfG Network Code modifications into Grid Code in advance of the RfG Network Code requirements coming into force to avoid the provisions in Article 4.3

Submission 3

One respondent commented that only the inherent behaviour of a generating unit is relevant for system stability. They commented that any control actions during a frequency transient, to compensate for the inherent power loss, will be too late or might further disturb the system e.g. when frequency is stabilised. They suggest that any requirement which does not consider the inherent behaviour would therefore exclude this technology from access to the system, disregarding all other benefits of this technology. For Synchronous PGMs it has to be taken into account that during a frequency drop (i.e. when the requirement is important) the inertia power response compensates the inherent power reduction to a certain amount (depending on the RoCoF). They further commented that compliance with this requirement is only for certain technologies only possible under certain ambient conditions – due to the fact that they show a strong relation between inherent power loss and ambient temperature. Hence, it does not make sense to link the requirement to a fixed ambient temperature. Furthermore a real test of compliance is not possible. Therefore, only a manufacturer statement based on calculations and simulations can be used as a proof of compliance.

SO Comments

Noted.

The ENTSO-E IGD "Maximum Admissible active power reduction at low frequencies" deals with system characteristics and the RfG Network Code requirements in order to support system frequency stability. This includes support in transient and steady state time domains when the frequency is stabilised. The proposed threshold frequency and slope chosen reflect the system characteristics of IE and the UK.

Considering technology characteristics in particular for SPGM Gas Turbines this is also discussed in the ENTSO-E IGD. The changes in performance can be mitigated depending on machine type and configuration. In May and June 2017 ENTSO-E conducted a consultation of European stakeholders to collect the most up to date information

The reduction rate of 2% of the maximum capacity at 50 Hz per 1 Hz frequency drop is in alignment with the ENTSO-E IGD. On page 7 section 2 it states it would make sense to have different requirements for different synchronous areas, i.e. UK, IE = 2%/Hz. At frequencies above 49.5Hz a drop in active power output is not permitted. This is a change as compared to the consultation proposal of 49Hz. Having considered the consultees' comments regarding capability under steady state conditions The TSO believes no power reduction above 49.5Hz to be reasonable for SPGM CCGT'S and in alignment with the ENTSO-E IGD's recommendation regarding steady state response. However The TSO would expect CCGT performance to be better than this in the transient time frame (see table on page 7 of ENTSO-E IGD up to 30secs)

As per the ENTSO-E IGD the PGM should provide the characteristics expected over a full temperature range (eg-10ºC - 40ºC). The performance specified under Article 13.5 is at 10ºC

Submission 5

One respondent commented that Article 13.5 is used to complement Article 13.4, by providing ambient condition and thus taking into consideration technical capabilities of the correspondent technology. They suggest a possible approach is to leave the characteristic as defined as reference for all and to request GT manufacturer to provide expected power deviation function of ambient temperature. They request that the TSO note that these requirements are critical only at full power for GT characteristic and the design is intrinsic to the all Gas Turbine category. They further note that the requirement cannot be tested and thus it is difficult to define improvement and it does not drive competition.

SO Comments

Noted.

The ENTSO-E IGD “Maximum Admissible active power reduction at low frequencies" deals with system characteristics and the RfG Network Code requirements in order to support system frequency stability. This includes support in transient and steady state time domains when the frequency is stabilised. The proposed threshold frequency and slope chosen reflect the system characteristics of IE and the UK.

Considering technology characteristics in particular for SPGM Gas Turbines this is also discussed in the ENTSO-E IGD. The changes in performance can be mitigated depending on machine type and configuration. In May and June 2017 ENTSO-E conducted a consultation of European stakeholders to collect the most up to date information

As per the ENTSO-E IGD the PGM should provide the characteristics expected over a full temperature range (eg-10ºC - 40ºC). The performance specified under Article 13.5 is at 10ºC

Submission 6

One respondent commented that compensative systems are risky and not fully beneficial. They can lead to flame out and are slow acting logic, not in line with supporting the initial stages of RoCoF. They reference the EUTurbine response to the ENTSO-E IGD on frequency parameters.

SO Comments

Considering technology characteristics in particular for SPGM Gas Turbines this is discussed in the ENTSO-E IGD. The changes in performance can be mitigated depending on machine type and configuration. In May and June 2017 ENTSO-E conducted a consultation of European stakeholders to collect the most up to date information

As per the ENTSO-E IGD the PGM should provide the characteristics 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 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	Consultation 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 PGMs	3

Table 5 Specify requirements for equipment to make this facility operable remotely for Type A

Justification

The RfG Network Code allows the RSO to specify requirements for equipment to enable the generator to cease active power output within 5 seconds and to operate remotely.

The TSO and DSO reserve the right to make this requirement mandatory for Type A PGMs. As the generation portfolio on the Power System changes it may be necessary for these units to cease active power output in order to maintain system security or safety.

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	Consultation Proposal	Article Number	Type Applicability	Justification Code
(i) Frequency Ranges and Time Delay	Non-specific	47 Hz to 50.2 Hz with a three minute delay	13.7	A, B, and C PGMs	3 1
(ii) Maximum admissible gradient of increase in power	Non-specific	10% of P_{max} per minute	13.7	A, B and C PGMs	1
(iii) Allowing automatic connection	A right to not allow	Allow automatic connection for Type A & B Do not allow automatic connection for Type C	13.7	A, B and C PGMs	1

Table 6 Conditions under which a PGMs is capable of connecting automatically to the network

Justification

The frequency ranges differ from the existing settings today and are highlighted with a '3' above to indicate this. The time delay is an existing requirement and is highlighted with a '1' above to indicate this.

The RfG Network Code allows the relevant system operator to specify the conditions under which a power-generating module is capable of connecting automatically to the network. The TSO currently does not use automatic connection and would specify that it is not allowed in Northern Ireland for Type C PGMs. However Engineering Recommendations G59 & G83 settings allow PGMs of sizes Type A and Type B to automatically connect once the frequency is within normal operating ranges. This right will be retained under the RfG.

The TSO would not wish to compromise system frequency stability by permitting Types A and B generator to connect automatically when the system frequency is above 50.2Hz since this action could cause high frequency instability. However, we would permit generation to automatically connect within the range 47 – 50.2Hz. This is why the proposal differs from the current settings today.

Consultation Response

Submission 1

One respondent commented that there is mismatch between the proposed parameter in the consultation response template and table 6 in this consultation document.

SO comments

The value above in Table 6 represents the correct value, which is 47Hz - 50.2Hz with a time delay of 3 minutes

Submission 2

One respondent commented that the automatic connection of Type A,B,&C PGM's at the specified frequency levels may affect the performance of other PGM's in terms of both the DS3 reserve and ramping products where there is a contracted response to a System Frequency event and when a dispatch instruction is issued. They are concerned that this could expose them to financial penalties under DS3 for MW deviations as well as exposure through the Balancing Market. They suggest that there needs to be a tolerance on DS3 performance to allow for this.

SO comments

For clarity only Type A and B PGM’s are permitted to automatically reconnect when the system frequency is within defined limits. The TSO has no control over these PGM’s and as such cannot issue an instruction to reconnect to the system. The ramp rate limitation of 10% of P_{max} per minute is included to limit the impact the automatic reconnection of this generation will have on the transmission system. System frequency will be taken into account in the performance monitoring process, and any change in frequency due to any action on the transmission system will be taken into account when assessing performance against required response.

Submission 3

One respondent requested clarification around the 10% of P_{max} proposal. The reference to "otherwise" in the following quote is unclear and should be clarified - "10% of P_{max} per minute after automatic reconnection. Otherwise power increase gradient limitation shall be in accordance with existing Grid Code ramp rate requirements e.g. CC.S2.1.3.7 and CC.S2.2.3.4."

SO Comments

This requirement in section 4.1.3.4 Article 13.7 allows automatic connection to the network for Type A & B PGM's only. This is made clear in table 6 above. The requirements in CC.S2.1.3.3 and CC.S2.2.3.4 are applicable to controllable or dispatchable WFPS's i.e. Type C & D PGM's only which as stated in the consultation will not be allowed to automatically reconnect.

Submission 4

One respondent commented that the following phrase *"The TSO currently does not use automatic connection and would specify that it is not allowed in Northern Ireland for Type C PGMs"* is misleading as The TSO does not have jurisdiction over automatic reconnection of generators which would be Type C PGMs. They further comment that the existing practice is determined by in the Distribution Code and Connection Agreements. They also comment that no justification for changing the existing practice has been presented.

They further comment that the following phrase *"Engineering Recommendations G59 & G83 settings allow PGMs of sizes Type A and Type B to automatically connect once the frequency is within normal operating ranges. This right will be retained under the RfG."* Is also misleading because G59/3 does not prohibit the automatic reconnection of generators which would be Type C PGMs. They provide the following text from the G59/83 settings as evidence:

- *"10.2.3 If automatic resetting of the protective equipment is used, there must be a time delay to ensure that healthy supply conditions exist for a minimum continuous period of 20s. Reset times may need to be co-ordinated where more than one Generating Plant is connected to the same feeder. The automatic reset must be inhibited for faults on the Generator's installation."*
- *"10.5.15 If automatic resetting of the protective equipment is used, as part of an auto-restore scheme for the Generating Plant, there must be a time delay to ensure that healthy supply conditions exist for a continuous period of at least 20 s. The automatic reset must be inhibited for faults on the Generator's installation. Staged timing may be required where more than one Generating Plant is connected to the same feeder. For Type Tested Generating Units the time delay is set at 20s"*

SO Comments

To ensure secure operation of the transmission system and maintain frequency stability the TSO does not allow automatic reconnection of Type D PGM's to the transmission and distribution systems. It is for the same reason that the TSO has proposed that this should also apply to Type C PGMs.

The Grid Code connection conditions in CC1.1, sets out criteria to be complied with by CDGU's and controllable WFPS connected to or seeking a connection to the Distribution System. Furthermore CC.S2.2.1 sets out the applicability of technical, design and operational criteria for WFPS connected to the Distribution system. The requirements in schedule 2 and the WFPS setting schedule are applicable to controllable WFP's or dispatchable WFPS's. The provisions of the Grid Code are applicable to controllable WFPS connected to the distribution system with a registered capacity of 5MW or more. CC.S2.2.1 (e) states that the DNO shall ensure protection equipment applied to generators with an output of 5MW or more should be incompliance with the requirements of Engineering recommendation G59.

G59 does allow for automatic resetting of protection equipment. In this case the TSO has chosen not to allow the reconnection of type C generators for the reasons described above.

Submission 5

One respondent commented that they do not agree with the proposal. They comment that if automatic reconnection is not allowed for Type C PGMs, then they could be out of service for longer than is necessary. They propose that Type C also be allowed to reconnect automatically when frequency is less than 50.2Hz.

SO Comments

To ensure secure operation of the transmission system and maintain frequency stability the TSO does not allow automatic reconnection of Type D PGM's to the Northern Ireland T&D systems. It is for the same reason that the TSO has proposed that this should also apply to Type C PGMs.

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	Consultation 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; in due time for plant design.	14.2 (b)	B PGMs	3

Table 7 Remote operation of Power Output

Justification

Due to the current levels of connected generation capacity, the TSO & DSO will require controllability of all Type B PGMs. 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 Responses

Submission 1

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

SO Comments

The SO agrees with this comment. The specification of equipment would be detailed as appropriate in the Distribution Code, settings schedule or Engineering recommendations all of which are under the governance of the DCRP

Submission 2

One respondent commented that the prioritization of the different logics should consider cogeneration plant. They recommend that specific agreements are put in place with generating plant where industrial facilities are depending on heat demand.

SO Comments

Assuming this response concerns PGM's combined heat and power facilities and industrial sites described in Article 6, the RSO will comply with the RfG Network Code Article 6, 3 - 5.

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	Consultation Proposal	Article Number	Type Applicability	Justification Code
The period within which the adjusted active power setpoint must be reached	No range provided	*PPM controllable generation* The Active power set point and the time to achieve this is determined by the TSO , however following shut down a PPM must commence active power export within 90secs WFPS setting schedule 6.11 (WFPS section 6.1, Wind following ramp rate 5MW per minute) *SPGM dispatchable generation* Active power set point and time to achieve the set point is given via TSO dispatch instructions in accordance with SDC2. Minimum ramp rates and start-up times specified in CC.S1.3.7 & CC.S1.2.3.4. (Grid Code CC.S1.1.3.7 (b) & (c) ramping up and de-loading at rate of at least 3% of MCR).	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	*PPM controllable generation* Active power output to be within 3% of set point (based on RC) Time to achieve set point within ±10 seconds of target time. (See WFPS Setting Schedule 6.1) *SPGM dispatchable generation* Tolerance bands for dispatch instructions is specified in OC11 Part B	15.2 (a)	C and D PGMs	3

Table 8: Achieving Active Power Set-points

Justification

Tolerance limits for dispatchable generation specifically SPGM's are as per the current operational and market monitoring tolerances. By aligning the tolerances for RfG Network Code with the current practices, it will ensure the monitoring and assessment of active power set point is consistent for dispatchable generation. For PPM controllable generation the chosen parameters for tolerances are in alignment with the current Grid Code requirements.

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 (controllable PPM generation) and does not apply to generation units where a dispatch instruction is issued via EDIL from the TSO to an operator to implement.

Consultation Responses

Submission 1

One respondent requested clarification on why the Northern Ireland required time start-up time for WFPS is shorter than the time period requested in Ireland

SO Comments

Both Grid Codes were developed in different time scales on a separate jurisdictional basis and have separate governance arrangements. One of the aims of the implementation of RfG Network Code is to introduce the requirements with minimal change to the existing national codes and it is not aiming to harmonise requirements in both jurisdictions.

Submission 2

One respondent commented that whilst they agree with the proposal this may be problematic in a scenario where wind turbines need time to yaw up to 180 degrees into the wind after an extended period of shut down. They suggest that this scenario should be noted in the proposal.

SO Comments

One of the aims of the implementation of RfG Network Code is to introduce the requirements with minimal change to the existing national codes. The WFPS settings schedule has been in place since 2012, this issue has not resulted in major failures of WFPS's to gain Grid Code compliance to date. However we will keep this under review.

Submission 3

One respondent commented that existing PGM's are not compliant with this as they met the System requirements in the past. They comment that any requirement to comply with this would require an OEM investigation and investment that would be subject to the CBA procedure outlined in this Network Code. They further comment that they are concerned that the TSO may attempt to have this changed in the current Grid Code prior to the Network Code coming into force, and so skip the requirement for a CBA. They comment that this previously happened with RoCoF leaving the existing generators with huge bills and little recompense through any other revenue stream.

SO Comments

For clarity the RfG Network Code requirements will apply to PGM facility owners who have concluded a final and binding contract for the purchase of their main plant generators after 17th May 2018. The TSO does not intend to introduce these RfG Network Code modifications into Grid Code in advance of the RfG Network Code requirements coming into force to avoid the provisions in Article 4.3

Submission 4

One respondent commented that this proposal may be challenging in the case of a fluctuating resource. They suggest that consideration be given to setting the limits based on suitable averaging period for example 10s, 1 min. They suggest that further engagement with OEMs would be necessary to set this specification.

SO Comments

One of the aims of the implementation of RfG Network Code is to introduce the requirements with minimal change to the existing national codes. The WFPS settings schedule has been in place since 2012, this issue has not resulted in major failures of WFPS's to gain Grid Code compliance to date. Further, as this RfG requirement is subject to the availability of the prime mover resource, we do not see the 3% requirement as being overly onerous. However we will keep under review.

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 free 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 '% curtailed' mode. 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 'emergency action' mode.

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	Emergency Action Mode	Not applicable in Northern Ireland today
LFSM-U	Not applicable in Northern Ireland today	Not applicable in Northern Ireland today
FSM Normal	% Curtailed Mode	Free Governor Action
FSM Frequency Step Change	Same 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	Consultation 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	2
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	2

Table 9: LFSM-O Parameter Selection

Justification: Frequency Threshold

In The TSO SPGM's do not operate in LFSM-O for the provision of FCR; these generators operate in FSM mode. LFSM-O is exclusively used in Northern Ireland by PPM's operating in emergency action mode and resource following mode. The current threshold specified in the WFPS setting schedule is 50.15Hz, the proposal is to adopt the minimum permissible threshold value in RfG Network Code of 50.2Hz.

Justification: Droop Settings

The Grid Code requires a droop setting for PPM's of between 2 - 20% (CC.S2.1.5.2 & CC.S2.2.5.2) and gas turbines are required to operate on a 4% droop (CC.S1.1.5.2 & CC.S1.2.4.2).The proposal is to adopt the RfG Network Code frequency droop range of between 2 - 12%. The existing Grid Code requirement for Gas turbines lies within this range and aligns with the default droop setting used across the island of Ireland which is 4%.

Consultation Responses

Submission 1

One respondent requested clarification on whether this value is now fixed to 50.2Hz and is not negotiable as currently this is agreed between the TSO and the PGM facility owner.

SO Comments

LFSM-O is exclusively used in Northern Ireland by PPM's (emergency action mode and resource following mode). The proposal is to adopt the minimum allowable value of 50.2Hz. The current WFPS Setting Schedule requires a value of 50.15Hz.

Submission 2

One respondent commented that currently the Grid Code sets the droop between 2-20%. They have concerns in relation to a DS3 proposal where PGMs would have a constantly dispatchable droop and a 10 Step response to Frequency movements. They are concerned with how this may impact other users of the power system.

SO Comments

LFSM-O is exclusively used in Northern Ireland by PPM's (emergency action mode and resource following mode)

The proposal of 2-12% is not in excess of the existing Grid Code requirements. Any proposals of the DS3 programme (including DS3 System Services) are outside of the scope of this consultation.

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	Consultation Proposal	Article Number	Applicable Type	Justification Code
Automatic disconnection and reconnection of PGMs	Allow or do not allow	Do not allow	13.2 (b)	A PGMs	3

Table 10: LFSM-O Automatic Disconnection & Reconnection

Justification

It is not currently planned to invoke this non-mandatory proposal for Type A generators. Which replaces LFSM-O with automatic disconnection of generation at frequencies above the frequency threshold.

Currently in addition to LFSM-O the RSO in coordination with the TSO can apply such settings to ensure the maintenance of frequency stability through disconnection of Type A PGMs. This will be agreed on a case by case basis as per current practice. The G59 & G83 engineering recommendations settings allow PGMs of size A to automatically connect once the frequency is within normal operating ranges. This right will be retained under the RfG. The reconnection of these units can occur when the frequencies have recovered.

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	Consultation 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 11: LFSM-O Actions at Minimum Regulating Level

Justification

The TSO's current practice is that when generators are scheduled and dispatched to operate at minimum generation level, there is no requirement for generators to provide negative regulation.

Therefore we propose that when generators reach their minimum regulation level that they continue operation at this level and don't further decrease active power output.

Consultation Responses

Submission 1

One respondent noted that there is a mismatch between the proposed parameter in the consultation response template and Table 11 in this document.

SO Comments

This is an error. The accurate proposal is to adopt that which is stated in the consultation document. For clarity:

(i) continuing operation at this level

Submission 2

One respondent commented that not every PGM is technically capable of reducing active power below minimum regulating level. They propose that the proposal is specified as: *further decreasing active power output if technically possible, ensuring continuous stable operation.*

SO Comments

This is an error. The accurate proposal is to adopt that which is stated in the consultation document. For clarity:

(i) continuing operation at this level

This proposal addresses these concerns.

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	Consultation 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	3
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	3

Table 12 LFSM-U Frequency Threshold & Droop Settings

Justification

LFSM-U is not currently used as a mode of frequency response in Northern Ireland. However looking to the future the introduction of new market conditions or system services may require LFSM_U for the provision of frequency restoration reserve (FRR), it is for this reason the above parameters for LFSM-U are specified

In Article 15 (c) (ii) it deals with the delivery of active power response in LFSM-U mode taking into account of ambient conditions. These ambient conditions are as described paragraphs 4 and 5 of Article 13.

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	Consultation Proposal	Article Number	Type Applicability	Justification Code
Active Power Range ($\Delta P/P_{max}$)	1.5-10%	Not proposing a value at this time 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 13 FSM Parameter Selection

Justification: Active Power Range

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

For this reason we are not proposing a value for active power range in Table 13.

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 Utility Regulator 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 specify requirements for Frequency Response insensitivity. It only specifies the Frequency Response Deadband. 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 (SOGL), the maximum combined effect of Frequency Response Insensitivity and Frequency Response Deadband cannot exceed a value of +/- 15 mHz.

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	Consultation Proposal	Article Number	Type Applicability	Justification Code
Active power range	1.5-10%	SPGMs: 10% 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	5 seconds	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	20	15.2 (d) (v)	C and D PGMs & offshore PPMs	3

Table 14 Activating full active power frequency response

Justification: Active Power Range

SPGM

This is specified during the connection process. At a full activation time of 5 seconds this is comparable with the existing requirements specified to generation during the connection process.

PPMs

The current requirements in the WFPS Setting Schedule requires a minimum of 60% of expected MW Output change value based on droop characteristic within 5 seconds and 100% of expected MW Output change value based on droop characteristic within 15 seconds. 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 Table 14 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 Utility Regulator 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

The current version of the WFPS Setting Schedule stated in section 6.5:

The TSO deems Fast acting with regards to Frequency Control response as being:

No time delays, such as moving average frequency filters, other than those necessarily inherent in the design of the Controllable WFPS shall be introduced.

Justification: Maximum admissible choice of full activation time

The choice of full activation time is 5 seconds in line with the existing MFS.

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

The Frequency Containment Reserves must remain in place until such time that the Frequency replacement reserves are available. In the case of Northern Ireland, the FCR equates to the POR, SOR, TOR1 and TOR2 under the Grid Code. As per today's Grid Code, Replacement Reserves must be made available from 20 minutes to four hours after the event.

Consultation Responses: Active Power Range

Submission 1

One respondent requested clarification around what is 100% in a multiple-units power plant (e.g. CCGT)

SO Comments

Maximum 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.

In the case of a CCGT (as defined in the Grid Code- GD12), the 100% refers to the Full load (as defined in the Grid Code- GD24) which is the maximum electrical output of a CCGT installation measured at the connection point.

Submission 2

One respondent commented that requirements should be on an equality principle and harmonized between Ireland and Northern Ireland.

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 3

One respondent commented that this proposal should be consulted on further with the OEMs. They further state that the System Operation Guideline Article 156.6 states "*that a single power generating unit is not allowed to cover more than 5% of the FCR of a synchronous area*" They suggest that SOGL be taken into account when defining the parameter of FSM to cover the reference imbalance incident (% of largest in feed). They further note that 10% in 5s is nearly impossible to achieve for conventional CCGT.

SO Comments

SOGL Article 156.6 (a) which limits FCR to 5% on any one unit only applies to CE and Nordic synchronous areas. Article 156.6 (b) which applies to IE/Northern Ireland simply requires the TSO's to ensure that the loss of any FCR providing unit does not endanger operational security.

The achievement of 10% in 5s has been a requirement for some time in Northern Ireland and has been demonstrated by CCGT SPGM's.

Submission 4

One respondent requested clarification on active power frequency response for WFPS, ideally in the form of additional guidance with for example benchmark behaviour. They further sought clarification on the speed of frequency response when increasing from significant active power curtailment e.g. below 40% of P_{max} and during periods of low wind speed.

SO Comments

The guidance you request and clarification for active power frequency response is detailed in the current version of the WFPS Setting Schedule section 6.5 and examples in Appendix E.

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 Utility Regulator with regard to these requirements in due course. Please see section 2.3 for more details.

Submission 5

One respondent requested clarification on this parameter as it appears to be inconsistent with the response required when the frequency deviation is sufficient to require the maximum response at that droop (delta F corresponding to delta P1 in RfG figure 5). They do not believe that this parameter is not related to the response required in 5 seconds, the POR timescale. They comment that RfG requires a definition of a related time t_2 to achieve delta P and are confused with the 15 seconds that the TSO has proposed. They further comment that this parameter does not supersede the current Grid Code requirement for 60% increase in power in 5s and 100% in 15s and request clarification on how this parameter will be applied.

SO Comments

The proposal in Table 14 presents the correct Maximum admissible choice of full activation time of 5 seconds. Both jurisdictions are aligned with a parameter selection of 5 seconds

Submission 6

One respondent comments that they do not see the requirement of dP/P_{max} in % as an error. They comment that it is common practice that the TSO defines an amount of reserve to allow for a better understanding and limitation of the governor free action.

SO Comments

The error described in the Justification in section 4.1.4.7 Article 15.2.d.(iii) of the consultation document is in respect of PPM type generation. The TSO is comfortable with the use of $(\Delta P/P_{max})$% which identifies the active power frequency response capability for SPGM's.

Consultation Responses: 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. They suggest that new System Services contracts of 1s should be established to provide enhanced capability from technologies capable of very fast response.

SO Comments

The TSO is proposing an immediate response (0 seconds) other than those delays inherent in the design of the frequency response system. The delays introduced by measurement equipment, the controller cycle time etc. are covered in the time delays allowed as part of those that are inherent in the design of the frequency response system. This is in alignment with definition of fast acting response described in section 6.5 of the current WFPS setting schedule introduced in 2012. The design and procurement of DS3 System Service contracts are outside the scope of this consultation.

Submission 2

One respondent commented that as this is a control action, 0s is not technically achievable. They propose the following text instead: *"no time delays other than those inherent in the design of the frequency response system, but not more than 2s"*

SO Comments

The proposal already captures the comments noted here. The TSO is proposing a delay of 0 seconds other than those delays inherent in the design of the frequency response system. This is in alignment with definition of fast acting response described in section 6.5 of the current WFPS setting schedule introduced in 2012.

Consultation Responses: Maximum admissible choice of full activation time

Submission 1

One respondent noted that there is a mismatch between the proposed parameter in the consultation response template and table 14 of this document. They note that the value in the template is in line with the ENTSO-E IGD on FSM

SO Comments

The proposal in Table 14 presents the correct Maximum admissible choice of full activation time of 5 seconds. Both jurisdictions are aligned with a parameter selection of 5 seconds

Submission 2

One respondent comments that frequency requirements should be on an equality principle and recommend that frequency parameters are harmonized in Ireland and Northern Ireland.

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 3

One respondent requested clarification on the values proposed. They note that the proposal is 5 seconds and not 15 seconds. 5 seconds is in line with current primary operating reserve response time. 15 seconds is in line with current secondary operating reserve response time. They understand "Maximum admissible choice of full activation time" to be the time required to deliver Active Power Range proposed above (10%). They further note that this parameter does not supersede the current Grid Code requirement for 60% increase in power in 5s and 100% in 15s. They would like to clarify how this parameter will be applied.

SO Comments

The proposal in Table 14 presents the correct Maximum admissible choice of full activation time of 5 seconds.

Submission 4

One respondent commented that the proposal for 5 s as full activation time, not 15s will not be achievable for SPGM in free governor mode without limitation of the reserve.

SO Comments

The proposal in Table 14 presents the correct Maximum admissible choice of full activation time of 5 seconds.

Please see The TSO response above for; Article 15.2.d.(iii): FSM: Step Change in Frequency (Active power range). The achievement of 10% in 5s has been a requirement for some time in Northern Ireland and has been demonstrated by SPGM's to date.

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

Submission 1

One respondent commented that they do not agree with the proposal here. They appreciate that the RfG requires the specification of a value in the range 15-30 minutes. They note that the current Grid Code does not require all generators to provide TOR2 and therefore this is a significant new requirement for certain PGMs.

SO Comments

One of the aims of the implementation of RfG Network Code is to introduce the requirements, and where possible, with minimal change to the existing national codes. Frequency containment reserves must remain in place until such time that the Frequency replacement reserves are available (FCR equates to POR, SOR, TOR1 & TOR2). As per today’s Grid Code, Replacement reserves must be made available from 20 minutes to 4 hours after a system event. It is for these reasons the 20 minute value has been chosen relating to the duration of the provision of full active power frequency response.

5.1.5 Additional Non-Mandatory Frequency Requirements

There are a number of additional areas with non-mandatory requirements detailed in the RfG. Table 15 identifies the areas. In all cases, we do not intend to invoke these non-mandatory requirements at this time.

Requirement	Requirement in RfG	Consultation 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 15 - 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
  - Supplementary requirements
  - At maximum capacity
  - Below maximum capacity
  - 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 16 specifies the voltage and duration settings.

Proposal

Parameter	Parameter in RfG	Consultation Proposal	Article Number	Type Applicability	Justification Code
Minimum Voltage below which Module will automatic disconnect	Not specified	Specified at plant design stage	15.3	C PGMs	1
Maximum Voltage above which Module will automatic disconnect	Not specified	Specified at plant design stage	15.3	C PGMs	1

Table 16: Parameters for Automatic Disconnection

Justification

Currently automatic disconnection for minimum and maximum voltage is required to establish anti-islanding protection as specified as part of Engineering Recommendations G59 and G83. The function within the generator would need to coordinate with these standards and is therefore to be specified at plant design stage.

Consultation Responses

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 suggest specification along the lines of "Specified at plant design stage to coordinate with G59 or G83 as the case may be." Otherwise the TSOs intent will be lost and inappropriate interpretations may be applied

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.

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

Table 17 specifies the voltage and duration settings.

Parameter	Parameter in RfG	Consultation 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 17: Type D Parameters for Automatic Disconnection

Justification: Automatic Disconnection Due to Voltage Level

The requirements as per today's Grid Code does not stipulate voltage threshold which allows for automatic disconnection. The TSO and DNO invoke the right to prohibit the automatic disconnection from the transmission and distribution systems.

Consultation Responses

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

Equipment design has high and low voltage limits according to applicable design rules, these should be considered here.

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 3

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.

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 4

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

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.

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 0 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

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

Parameter	Requirement	Requirement in RfG	Consultation Proposal	Article Number	Type Applicability	Justification Code
Low Voltage	umin	0.875 p.u.	0.94 p.u.	17.2 (a) & 20.2 (a)	B	1
	u_{max}	1.1 p.u.	1.1 p.u.	17.2 (a) & 20.2 (a)	B	1
	Q_{min}/P_{max} (lead)	-0.5 p.u.	-0.33 p.u.	17.2 (a) & 20.2 (a)	B	1
	Q_{max}/P_{max} (lag)	0.65 p.u.	0.203 p.u.	17.2 (a) & 20.2 (a)	B	1
Below 110 kV	u_{min}	0.875 p.u.	0.94 p.u.	17.2 (a) & 20.2 (a)	B	1
	u_{max}	1.1 p.u.	1.06 p.u.	17.2 (a) & 20.2 (a)	B	1
	Q_{min}/P_{max} (lead)	-0.5 p.u.	-0.33 p.u.	17.2 (a) & 20.2 (a)	B	1
	Q_{max}/P_{max} (lag)	0.65 p.u.	0.203 p.u.	17.2 (a) & 20.2 (a)	B	1

Table 18: Right to specify reactive power capability for SPGMs

Justification

The Distribution Code specifies a range for power stations of 0.95pf leading to 0.98pf lagging. This is equivalent to a range of -0.33 Q_{min}/P_{max} (lead) to 0.203 Q_{min}/P_{max} (lag).

Consultation Responses

Submission 1

Two respondents 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 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 fulfil the rectangular inner envelope shape.

Submission 2

One respondent requested clarification that the power factor is 0.95 / 0.98 / 0.95 / 0.98 for low voltage and below 110 kV respectively for generators.

SO Comments

The requirements and shape of the inner envelope are as per today’s Distribution Code requirements and are measured at the connection point. For power stations >100kW and <5MW the Distribution Code currently specifies a range of 0.95pf leading to 0.98pf lagging. This is equivalent to a range of -0.33 Q_{min}/P_{max} (lead) to 0.203 Q_{min}/P_{max} (lag).

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

Parameter	Requirement	Requirement in RfG	Consultation Proposal	Article Number	Type Applicability	Justification Code
Low Voltage	u_{min}	0.875 p.u.	0.94 p.u.	17.2 (a) & 20.2 (a)	B	1
	u_{max}	1.1 p.u.	1.1 p.u.	17.2 (a) & 20.2 (a)	B	1
	Q_{min}/P_{max} (lead)	-0.5 p.u.	-0.33 p.u.	17.2 (a) & 20.2 (a)	B	1
	Q_{max}/P_{max} (lag)	0.65 p.u.	0.203 p.u.	17.2 (a) & 20.2 (a)	B	1
Below 110 kV	u_{min}	0.875 p.u.	0.94 p.u.	17.2 (a) & 20.2 (a)	B	1
	u_{max}	1.1 p.u.	1.06 p.u.	17.2 (a) & 20.2 (a)	B	1
	Q_{min}/P_{max} (lead)	-0.5 p.u.	-0.33 p.u.	17.2 (a) & 20.2 (a)	B	1
	Q_{max}/P_{max} (lag)	0.65 p.u.	0.203 p.u.	17.2 (a) & 20.2 (a)	B	1

Table 19: Right to specify reactive power capability for PPMs

Justification

The Distribution Code specifies a range for power stations of 0.95pf leading to 0.98pf lagging. This is equivalent to a range of -0.33 Q_{min}/P_{max} (lead) to 0.203 Q_{min}/P_{max} (lag).

Consultation Responses

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/P_{max} coordinates. They assume a rectangle corresponding to these coordinates.

SO Comments

Parameters proposed in the document determine the four corners of the rectangular inner envelope. This is applicable for all generators connected @ voltage level ≥110 kV.

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}).

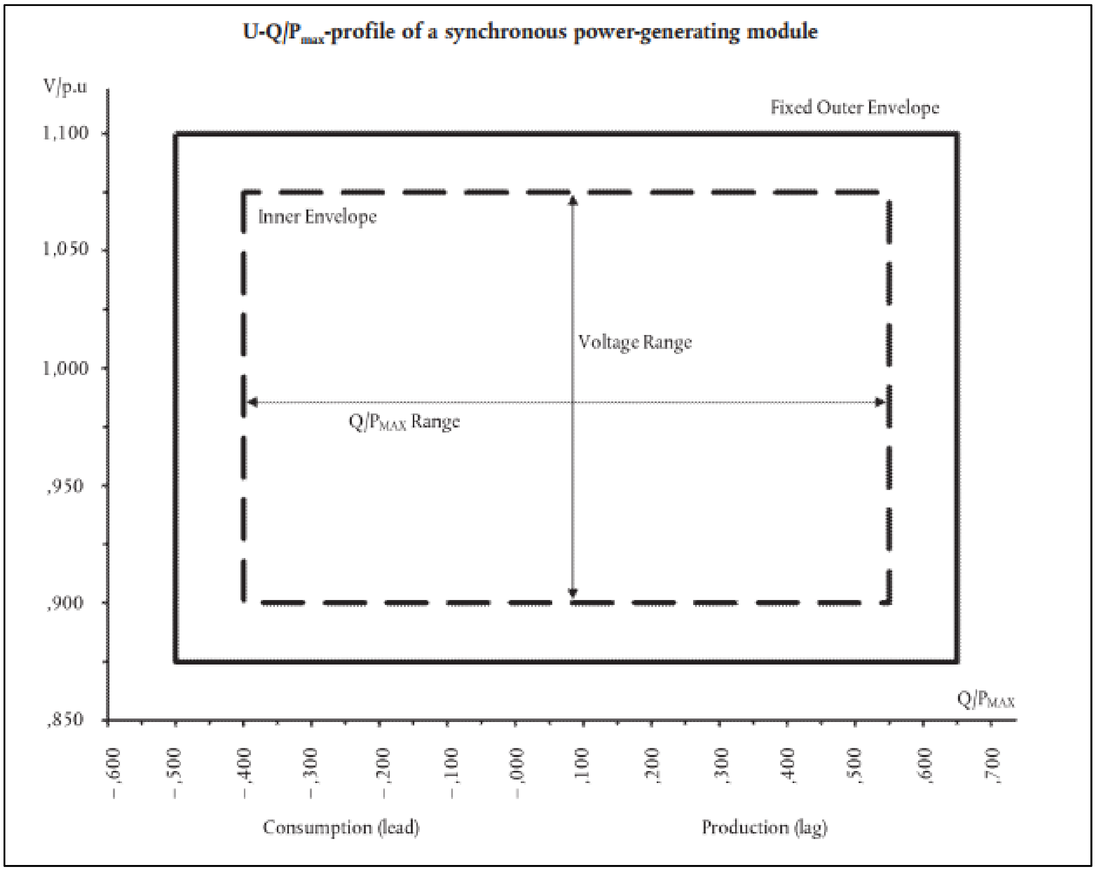


Figure 2: U-Q/P_{max}-profile for synchronous Power-Generating Modules

Figure 2 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 envelope are indicative. The dimensions of the inner envelope are limited by a maximum range of Q/P_{max} of 1.08 and maximum range of steady state voltage level of 0.218 p.u.

Proposal for SPGMs connected at a voltage level ≥ 110 kV

Table 20 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)	Consultation 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}	1.1 p.u.	1.1 p.u.			1
	Q_{min}/P_{max} (lead)	-0.5 p.u.	-0.48 p.u.			3
	Q_{max}/P_{max} (lag)	0.65 p.u.	0.6 p.u.			3
275 kV	u_{min}	0.875 p.u.	0.9 p.u.			1
	u_{max}	1.1 p.u.	1.1 p.u.			1
	Q_{min}/P_{max} (lead)	-0.5 p.u.	-0.48 p.u.			3
	Q_{max}/P_{max} (lag)	0.65 p.u.	0.6 p.u.			3
400 kV	u_{min}	0.875 p.u.	0.875 p.u.			3
	u_{max}	1.1 p.u.	1.05 p.u.			3
	Q_{min}/P_{max} (lead)	-0.5 p.u.	-0.48pu			3
	Q_{max}/P_{max} (lag)	0.65 p.u.	0.6 p.u.			3

Table 20: Definition of U-Q/Pmax-profile at Maximum Capacity for SPGMs: connection @ ≥110 kV

Justification: SPGMs connected at a voltage level ≥ 110 kV

The existing reactive power range in the Grid Code is specified as 0.95pf leading to 0.8pf lagging, measured at the generator terminals (see CC.S1.3.2). This has been approximated to the connection point as range -0.48 p.u. Q_{min}/P_{max} (lead) to 0.6 p.u. Q_{max}/P_{max} (lag). These are within the range required by the RfG. The Grid Code requirements may need to be changed to specify the requirements at the connection point rather than at the generator terminals.

There is current no 400 kV operating voltage in Northern Ireland. As and when the proposed Turleenan – Woodland 400 kV circuit is constructed this will introduce a 400 kV node into the Northern Ireland transmission system. The voltage range chosen for the 400 kV voltages are aligned with the Ireland Grid Code.

Consultation Responses

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 non-RfG applicable generators or the HV terminals or connection point for RfG applicable generators.

RfG does apply to the following generators:

- New i.e. those generators whose main plant & equipment is procured post May 2018

- 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 a review 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 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 fulfil the rectangular inner envelope shape.

Submission 4

One respondent commented that the voltage and Q/P_{max} 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. For this matter it is not part of the consultation process.

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 P_{max} 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 as per today's Grid Code requirements. 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 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 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 fulfil the rectangular inner envelope shape.

Submission 10

Max. leading operation (Q_{min}/P_{max} (lead)=-0,48) at GSU HV terminals shall not be required for HV voltages U<Urated.

Max. leading (under-excited) operation of the generator at lowest grid voltage level is technically not required.

SO Comments

The requirements and shape of the inner envelope are as per today's Distribution Code Requirements and are measured at the connection point. For power stations >5MW the Distribution Code currently specifies a range of 0.95pf leading to 0.95pf lagging. This is equivalent to a range of -0.33 Q_{min}/P_{max} (lead) to 0.33 Q_{min}/P_{max} (lag).

Submission 11

Max. lagging operation (Q_{max}/P_{max} (lag)=0,60) at GSU HV terminals shall not be required for HV voltages U>1,05Urated

Max. lagging (overexcited) operation of the generator at highest grid voltage level is technically not required."

SO Comments

The TSO has converted the existing Grid Code requirements and parameters to their equivalent as measured at the connection point as required by RfG Network Code.

Proposal for SPGMs connected at a voltage level < 110 kV

Table 21 below lists the parameters which describe the U-Q/P_{max}-profile for SPGMs connection at a voltage level < 110 kV.

Connection Voltage	Parameter	Parameter in RfG (outer envelope)	Consultation Proposal (Inner Envelope)	Article Number	Type Applicability	Justificati Code
Below 110 kV	u_{min}	0.875 p.u.	0.94 p.u.	18.2.b (ii)	C and D SPGMs	1
	u_{max}	1.1 p.u.	1.06 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	1
	Q_{max}/P_{max} (Export)	0.65 p.u.	0.33 p.u.	18.2.b (ii)	C and D SPGMs	1

Table 21: Definition of U-Q/Pmax-profile at Maximum Capacity for SPGMs: connection @ <110 kV

Justification: SPGMs connected at a voltage level <110 kV

The Distribution Code specifies a range for power stations of 0.95pf leading to 0.95pf lagging. This is equivalent to a range of -0.33 Q_{min}/P_{max} (lead) to 0.33 Q_{min}/P_{max} (lag).

Consultation Responses

Submission 1

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, from the National Grid, Grid Code CC.6.3.4 and from the VDE AR-4120, where different possible 'internal' shapes are provided to be chosen by the SO to adopt.

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

Submission 2

One respondent requested clarification that the power factor is 0.95 / 0.95 for low voltage and below 110 kV respectively for generators.

SO Comments

Yes that is correct; 0.33 p.u. is 0.95 power factor.

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	Consultation Proposal	Article Number	Type Applicability	Justification Code
Time to achieve target value	Not specified	Without undue delay but at least within 120 seconds	18.2.b (iv)	C and D SPGMs	3

Table 22: Timescales to Achieve Target Values at Maximum Capacity

Justification

The time to achieve the target value is a new parameter in the Grid Code and the Distribution Code. The time to achieve the target value is aligned with the current requirement set out in the Ireland Grid Code in the Scheduling and Dispatch Code Appendix B (SDC2.B.8) 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.

Consultation Responses

Submission 1

The proposed value of 120 second time scale shall be increased. To move from full lagging to full leading requires the use of GSU taps on large generating units. 120 s time scale to achieve extreme operating Q_{min}/Q_{max} points by moving and instructing the GSU's taps will take longer than 120 second since several tap instructions will be required. What assumption was made for typical tap-changer operation time per tap?

SO Comments

A Dispatch Instruction relating to Reactive Power will be implemented without delay 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. This aligns with the Ireland requirements for CDGUs as Northern Ireland does not currently specify this parameter.

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}).

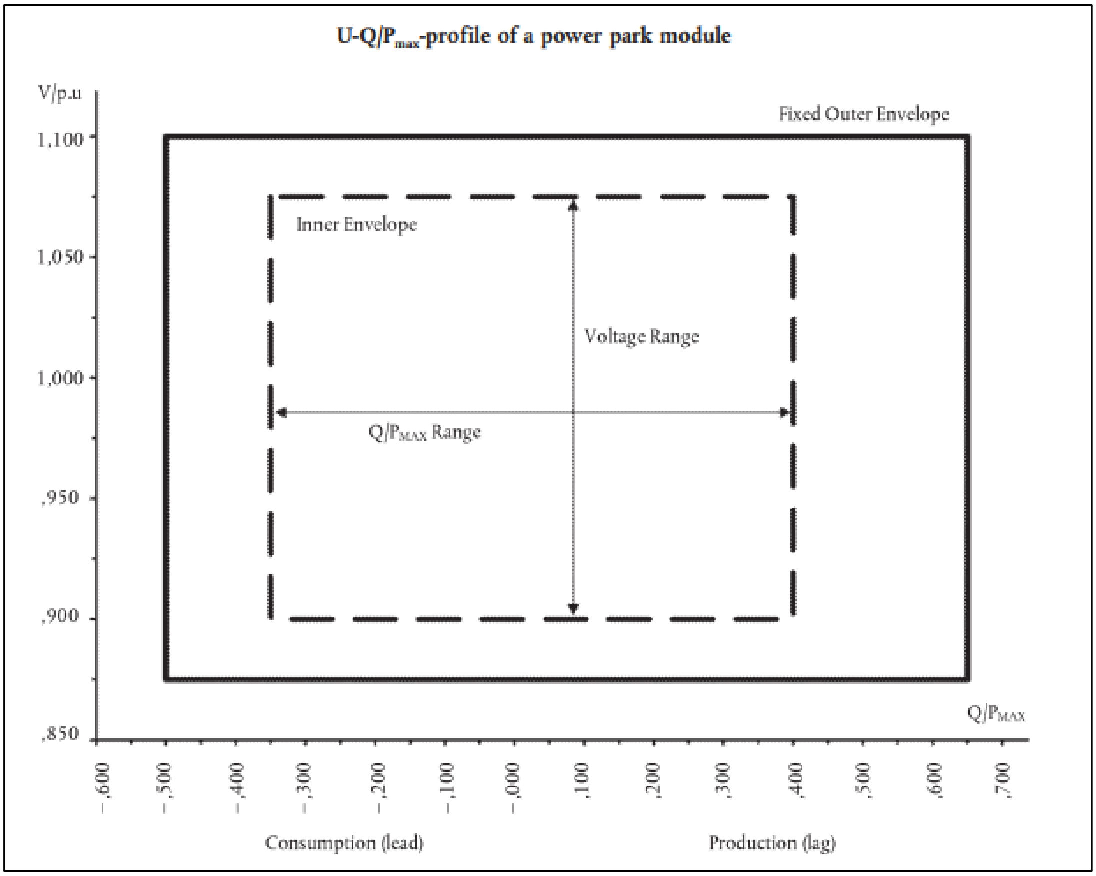


Figure 3: U-Q/P_{max}-profile for Power Park Modules

Figure 3 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 23 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)	Consultation 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 & offshore PPMs	1
	u_{max}	1.1 p.u.	1.1 p.u.	21.3.b (ii)	D PPMs & offshore PPMs	1
	Q_{min}/P_{max} (lead)	-0.5 p.u.	-0.33 p.u.	21.3.b (ii)	D PPMs & offshore PPMs	1
	Q_{max}/P_{max} (lag)	0.65 p.u.	0.33 p.u.	21.3.b (ii)	D PPMs & offshore PPMs	1
275 kV	u_{min}	0.875 p.u.	0.9 p.u.	21.3.b (ii)	D PPMs & offshore PPMs	1
	u_{max}	1.1 p.u.	1.1 p.u.	21.3.b (ii)	D PPMs & offshore PPMs	1
	Q_{min}/P_{max} (lead)	-0.5 p.u.	-0.33 p.u.	21.3.b (ii)	D PPMs & offshore PPMs	1
	Q_{max}/P_{max} (lead)	0.65 p.u.	0.33 p.u.	21.3.b (ii)	D PPMs & offshore PPMs	1
400 kV	u_{min}	0.875 p.u.	0.875 p.u.	21.3.b (ii)	D PPMs & offshore PPMs	3
	u_{max}	1.1 p.u.	1.05 p.u.	21.3.b (ii)	D PPMs & offshore PPMs	3
	Q_{min}/P_{max} (lead)	-0.5 p.u.	-0.33 p.u.	21.3.b (ii)	D PPMs & offshore PPMs	1
	Q_{max}/P_{max} (lag)	0.65 p.u.	0.33 p.u.	21.3.b (ii)	D PPMs & offshore PPMs	1

Table 23: Definition of a U-Q/Pmax-profile at Maximum Capacity PPMs: connected @ ≥ 110 kV

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

The Grid Code specifies a range for wind farm power stations of 0.95pf leading to 0.95pf lagging. This is equivalent to a range of -0.33 Q_{min}/P_{max} (lead) to 0.33 Q_{min}/P_{max} (lag).

There is currently no 400 kV system in Northern Ireland. The values chosen above are aligned with the Ireland Grid Code.

Consultation Responses

Submission 1

Two respondents 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 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 fulfil the rectangular inner envelope shape.

Proposal for PPMs connected at a voltage level < 110 kV

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

Connection Voltage	Parameter	Parameter in RfG (outer envelope)	Consultation Proposal (Inner Envelope)	Article Number	Type Applicability	Justification Code
Below 110 kV	u_{min}	0.875 p.u.	0.94 p.u.	21.3.b (ii)	C and D PPM and offshore PPMs	1
	u_{max}	1.1 p.u.	1.06 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	1
	Q_{max}/P_{max} (lag)	0.65 p.u.	0.33 p.u.	21.3.b (ii)	C and D PPM and offshore PPMs	1

Table 24: Definition of a U-Q/Pmax-profile at Maximum Capacity PPMs connected @ <110 kV

Justification: PPMs connected at a voltage level <110 kV

The Distribution Code specifies a range for power stations of 0.95pf leading to 0.95pf lagging. This is equivalent to a range of -0.33 Qmin/ P_{max} (lead) to 0.33 Qmin/ P_{max} (lag).

Consultation Responses

Submission 1

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 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 fulfil the rectangular inner envelope shape.

5.2.2.3 Reactive Power Capability below Maximum Capacity: P-Q/P_{max} Profiles

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

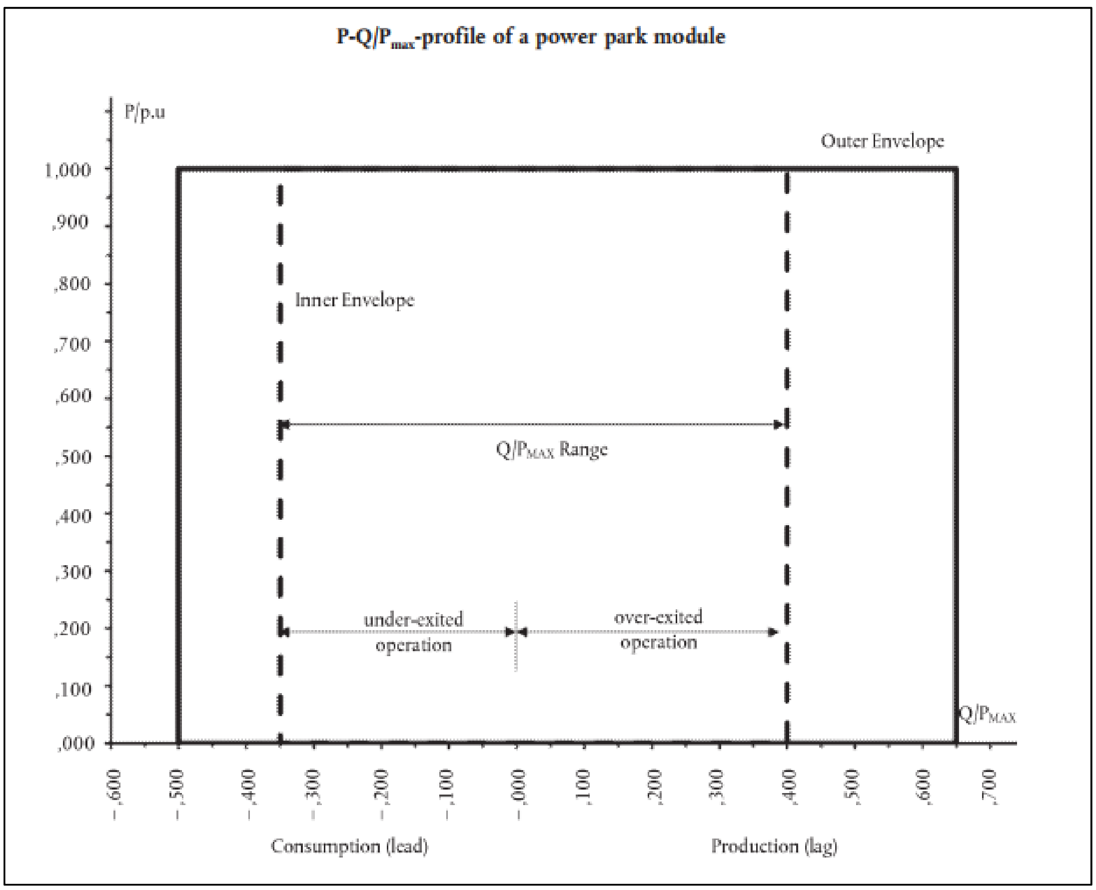
Non-Exhaustive Parameter Selection

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.



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 25 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	Consultation 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 25: Definition of a U-Q/Pmax-profile at Maximum Capacity PPMs connected @ ≥110 kV

Justification: PPMs connected at a voltage level ≥ 110 kV

The proposals above are consistent with the existing Grid Code for Wind Farm power stations.

Proposal PPMs connected at a voltage level < 110 kV

Table 26 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	Consultation Proposal	Article Number	Type Applicability	Justification Code
Below 110 kV	p_{min}	0.0 p.u.	0.15 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 26: P-Q/Pmax-profile below Maximum Capacity PPMs: connection @ <110 kV & in Topology 2

Justification: PPMs connected at a voltage level <110 kV

The Distribution Code specifies that power stations should be able to operate over a range of reactive power of -0.33 Q_{min}/ P_{max} (lead) to 0.33 Q_{min}/ P_{max} (lag) at all active power outputs from P_{max} to a P_{min} value of 0.15p.u.

Consultation Responses

Submission 1

One respondent agrees with the Pmin proposal. However does the P-Q capability have to rectangular for distribution connected generators?

SO Comments

The requirements and shape of the inner envelope are as per today's Distribution Code requirements and are measured at the connection point. For power stations >5MW the Distribution Code currently specifies a range of 0.95pf leading to 0.95pf lagging. This is equivalent to a range of -0.33 Q_{min}/P_{max} (lead) to 0.33 Q_{min}/P_{max} (lag) at all active power outputs from P_{max} to a P_{min} value of 0.15p.u.

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

Non-Exhaustive Parameter Selection

Applies to Type C and D PPMs

Requirement

(v) the PPM 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	Consultation 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 PPM	3
Time to achieve target value [distribution connected]	Not specified	Without delay but within 20 seconds	21.3.c.(iv)	C and D PPM	3

Table 27: Timescales to Achieve Target Values at Maximum Capacity

Justification

This aligns with the current WFPS Setting Schedule 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	Consultation 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 28: 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.

Consultation Responses

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 today's Grid Code requirements.

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	Consultation 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 29: 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 (Shallow Connection Design).

Consultation Responses

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.

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 PGMs

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 30.

Parameter	Parameter in RfG	Consultation 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 PGMs	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 PGMs	1

Table 30: Parameters of the Voltage Control Mode

Justification

These requirements are currently detailed in the WFPS Settings Schedule.

PPMs shall be able to perform Direct Voltage Control With Slope:

Whilst the PPM is operating in this Voltage Control mode, it is required to respond as follows:

Voltage Control of PPM in response to a Voltage set point received: The Generator will ensure the PPM is capable of performing Closed-loop Voltage Control (without a slope) with proportional-integral action with responses in a stable manner. i.e. if a Voltage set point instruction is received by the PPM via SCADA, the PPM will achieve the set point if it has the reactive capability to do so.

Voltage Control of PPM in response to a System Voltage perturbation after a Voltage set point received via SCADA has been achieved: When the required voltage set point has been achieved (if the reactive capability of the PPM is there to do so) the PPM will operate on a reactive slope characteristic to System Voltage perturbations.

The Voltage Control System of the PPM should have a reactive slope characteristic which must be adjustable over a range of between 2 - 7% with a resolution of 0.5%. The PPM must demonstrate the ability to operate on a 3% reactive slope characteristic.

Therefore if the System voltage drops by 3% below the voltage set point received via SCADA, the PPM will go to its maximum lagging Reactive Power capability and export the maximum Reactive Power of the PPM on to the System. Conversely, if the System voltage increases by 3% above the voltage set point received via SCADA, the PPM will go to its maximum leading Power Factor and absorb the maximum amount of Reactive Power possible from the System. The magnitude of the Reactive Power output response shall vary linearly in proportion to the magnitude of the step change in voltage.

Performance Criteria Required:

The speed of response of the voltage regulation System, following a step change in voltage at the connection point, shall be such that the change in reactive power commences within 0.2 seconds of the application of the step injection

The PPM shall achieve 90% of its steady-state Reactive Power response within 1 second(t1).

Any oscillations settle to within 5% of the change in steady state Reactive Power within 2 seconds of the application of the step injection.

The final steady state reactive value is achieved within 5 seconds (t2) of the step application.

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

Non-Exhaustive Parameter Selection

Applies to Type C and D PGMs

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 31.

Parameter	Parameter in RfG	Consultation Proposal	Article Number	Type Applicability	Justification Code
Target power factor	Not specified	site-specific	21.3.d.(vi)	C and D PGMs	3
Time period to reach the set point	Not specified	5 seconds	21.3.d.(vi)	C and D PGMs	3
Tolerance	Not specified	5%	21.3.d.(vi)	C and D PGMs	3

Table 31: Parameters of the Power Factor Control Mode

Justification

These requirements are currently detailed in the WFPS Settings Schedule (Version). 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 parameters are proposed to be site-specific.

PPMs shall be able to perform Power Factor Control:

Whilst the PPM is operating in this Power Factor Control mode, it is required to respond as follows:

- The speed of response of the power factor control system, following a change in the power factor set point at the connection point, shall be such that the change in reactive power commences within 0.2 seconds of the application of the step injection.
- The PPM shall achieve 90% of its steady-state reactive power response within 1 second.
- Any oscillations settle to within 5% of the change in steady state Reactive Power within 2 seconds of the application of the step injection.
- The final steady state reactive value according to the slope characteristic is achieved within 5 seconds of the step application.

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 in Table 32.

Proposal

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

Table 32: 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 levels 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.

Consultation Responses

Submission 1

The TSO has stated that the requirement to fit a PSS is due to the generation profile on the system; these connections have been allowed by the TSO so this equipment should be funded by the TSO.

SO Comments

The TSO would have the view that it is more economic to include the cost of the PSS with the installation of the power station rather than attempting to retrofit. With the market and the lighter more uncertain nature of the transmission system now and into the future, the TSO believes that it should have the flexibility to establish quickly PSS schemes when they are required in Real Time.

This requirement is not retrospective and this RfG requirement will not require any power station that currently does not have a PSS to now install one.

Ordinarily the SPGM facility owner covers all of the costs of the new connection and everything on their side of the connection point, including any additional control systems or devices that are required.

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

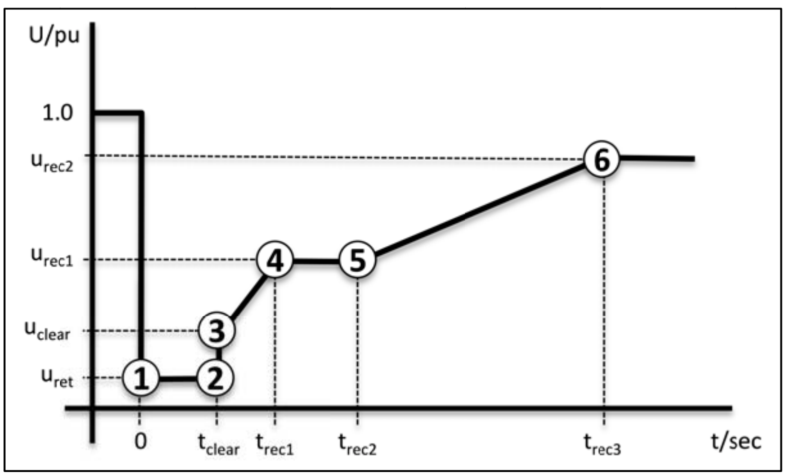
5.2.4.1 Article 14.3.a & 16.3.a: FRT Capability for PGMs connected at voltage level <110 kV

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

Voltage parameters (p.u.)			Time parameters (s)			Justification Code
Parameter	RfG Range	Proposal	Term	RfG Range	Proposal	
U_{ret}	0.05-0.3	0.05	t_{clear}	0.14-0.25	0.15	3
U_{clear}	0.7-0.9	0.7	t_{rec1}	t_{clear}	t_{clear}	3
U_{rec1}	U_{clear}	U_{clear}	t_{rec2}	t_{rec1}-0.7	0.45	3
U_{rec2}	0.85-0.9 & >=U_{clear}	0.9	t_{rec3}	t_{rec2}-1.5	t_{rec2}	3

Table 33: Definition of FRT parameters for SPGMS connected @ <110 kV

Justification: SPGMs connected at a voltage level <110 kV

The Distribution Code does not provide fault ride through requirement for synchronous generators that are compliant with the above. The most onerous retained voltage is chosen to reflect the radial nature of the Northern Ireland distribution system. The fault clearance time is also chosen as the most onerous to reflect the type of protection schemes used on the distribution system.

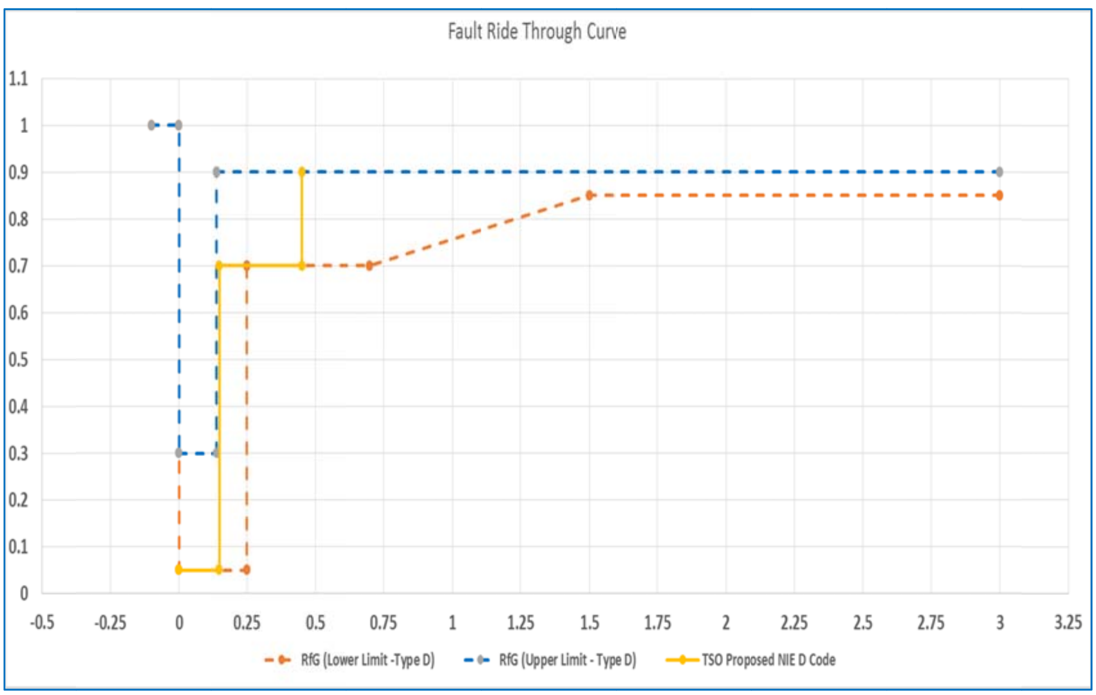


Figure 4: FRT capability synchronous PGM connected at voltage less than 110 kV

Consultation Responses

Submission 1

One respondent commented that the FRT requirements for SPGMs should be based on a minimum grid short circuit power of 6x P_{max} in MVA (example: P_{max} =250MW □ Skmin=1500MVA). They state that this is proposed to reflect the short circuit power in the HV system to which the generating unit is connected. As low as the short circuit power is as low is the FRT critical time

SO Comments

The TSO considers minimum system strength to be closely related to power quality issues for example harmonics. Even with high short circuit power there is still the potential for voltage levels to reduce significantly during short circuit conditions.

Submission 2

One respondent commented that these values (and specifically the 5% Un) 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

There will be significant levels of embedded generation on the distribution system and the SO wants the RfG requirements applicable to PGMs connected to the distribution system, to be closely aligned to those that apply to the transmission system connected PGMs.

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

Voltage parameters (p.u.)			Time parameters (s)			Justification Code
Parameter	RfG Range	Proposal	Parameter	RfG Range	Proposal	
U_{ret}	0.05-0.15	0.15	t_{clear}	0.14-0.25	0.25	3
U_{clear}	U_{ret} -0.15	0.15	t_{rec1}	t_{clear}	t_{clear}	3
U_{rec1}	U_{clear}	U_{clear}	t_{rec2}	t_{rec1}	t_{clear}	3
U_{rec2}	0.85	0.85	t_{rec3}	1.5-3.0	2.9	3

Table 34: Definition of FRT parameters for PPMs connected @ <110 kV

Justification: PPMs connected at a voltage level <110 kV

The fault ride through requirements in the existing Distribution Code are indicated in Figure 8 below. The modifications made are considered to be the minimum required to comply with the RfG.

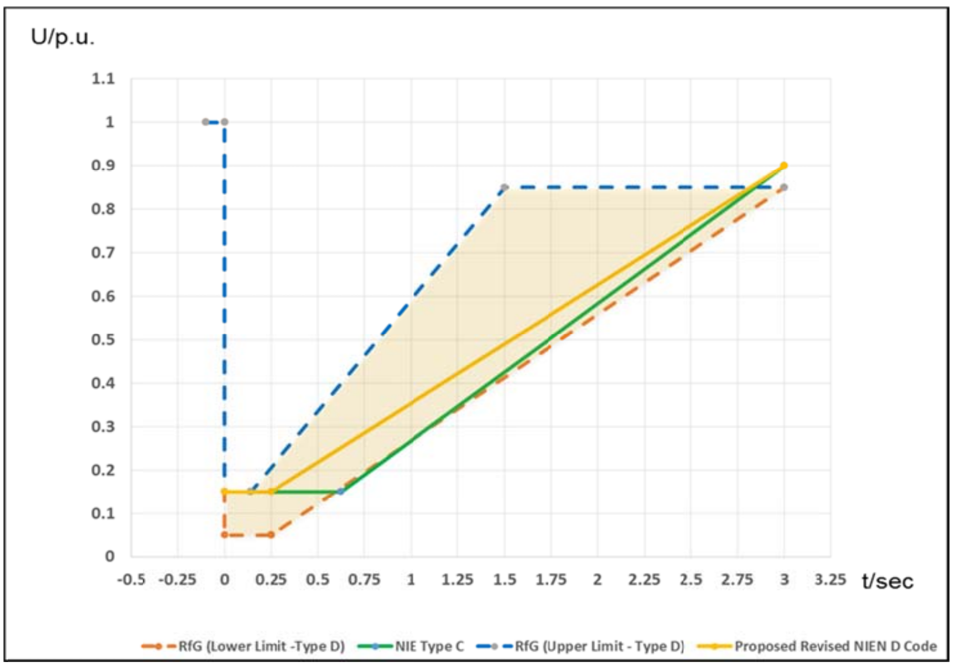


Figure 5: FRT capability PPM connected at voltage less than 110 kV

Consultation Responses

Submission 1

250ms is deemed too long and outside international practice, we suggest 150ms

SO Comments

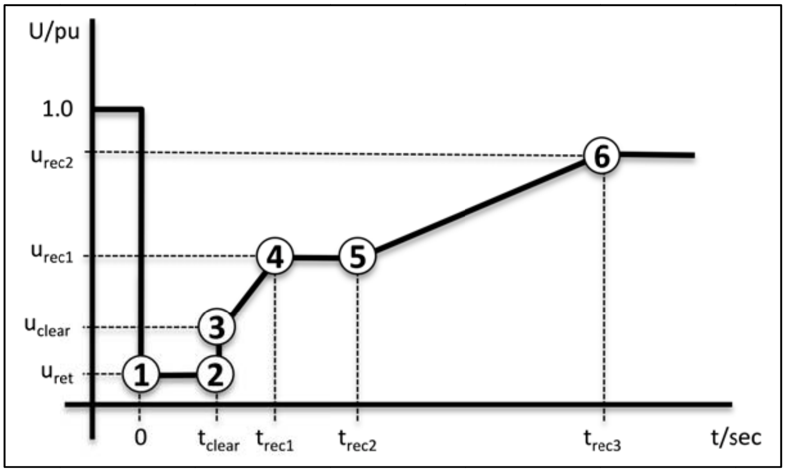
The current Grid and Distribution Code requirements require PPMs to remain connected for much longer fault durations than 150 ms or even 250 ms. As set out in section 3.1 the intention is to maintain the existing requirements in the Grid Code were possible. We have chosen 250 ms to as closely align with the existing requirements as possible.

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 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 the 110 kV level in the following subsections.

Proposal: SPGMs connected at a voltage level ≥ 110 kV

Table 35 lists the parameters which describe the FRT capability parameters for SPGMs connection at a voltage level ≥ 110 kV.

Voltage parameters (p.u.)			Time parameters (s)			Justification Code
Parameter	RfG Range	Proposal	Term	RfG Range	Proposal	
U_{ret}	0	0	t_{clear}	0.14-0.25	0.15	3
U_{clear}	0.25	0.25	t_{rec1}	t_{clear} -0.45	t_{clear}	3
U_{rec1}	0.5-0.7	0.5	t_{rec2}	t_{rec1}-0.7	0.45	3
U_{rec2}	0.85-0.9	0.9	t_{rec3}	t_{rec2}-1.5	t_{rec2}	3

Table 35: Definition of FRT parameters for SPGMs connected @ ≥110 kV

Justification: SPGMs connected at a voltage level ≥110 kV

The Grid Code does not provide fault ride through requirement for synchronous generators that are compliant with the above. The proposal is based on the proposed modifications to the Grid Code and Distribution Code for the equivalent module.

Figure 6 shows the fault ride through capabilities including for completeness, the RfG boundaries.

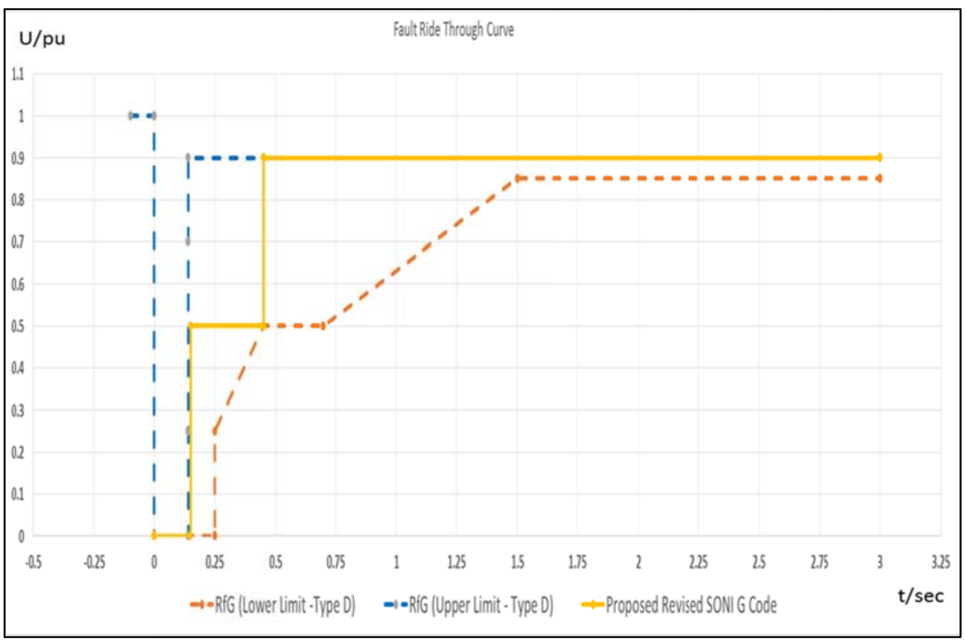


Figure 6: FRT capability of SPGMs connected at ≤ 110 kV

Consultation Responses

Submission 1

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 2

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.

Submission 3

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 system voltage dips.

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.

Proposal: PPMs connected at a voltage level ≥ 110 kV

Table 36 lists the parameters which describe the FRT capability parameters for PPMs connection at a voltage level ≥ 110 kV.

Voltage parameters (p.u.)			Time parameters (s)			Justification Code
Parameter	**RfG Range**	**Proposal**	**Term**	**RfG Range**	**Proposal**	
U_{ret}	0	0	t_{clear}	0.14-0.25	0.15	3
U_{clear}	U_{ret}	U_{ret}	t_{rec1}	t_{clear}	t_{clear}	
U_{rec1}	U_{clear}	U_{clear}	t_{rec2}	t_{rec1}	t_{clear}	
U_{rec2}	0.85	0.85	t_{rec3}	1.5-3.0	2.9	3

Table 36: Definition of FRT parameters for PPMs connected @ ≥ 110 kV

Justification: PPMs connected at a voltage level ≥110 kV

The proposal above is based on the fault ride through contained within the Grid Code for Wind Farm power stations (WFPS). The retained voltage is required to be reduced to zero the fault clearance time reduced to 0.15 seconds. The term WFPS will be amended to use the same terminology as the RfG. Figure 7 shows the fault ride through capabilities including the RfG boundaries.

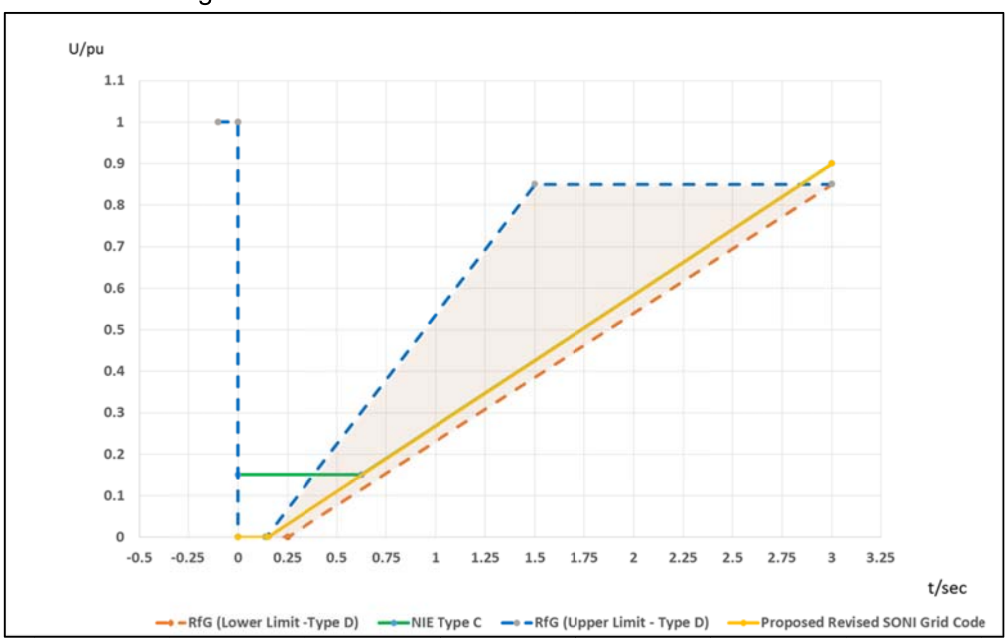


Figure 7: FRT capability of PPMs connected at ≤ 110 kV

5.2.4.2 Fast Fault Current Injection

5.2.4.2.1 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	Consultation Proposal	Article Number	Type Applicability	Justific Co
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	3
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	3
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	3
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	3

Table 37: Fast Fault Current Injection - Symmetrical Faults

Justification:

The existing Distribution Code and Grid Code are silent on the provision of fast fault current. The DNO and TSO invoke 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 conditions given.

Consultation Responses

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 was not part of the consultation process.

Submission 2

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.

5.2.4.2.2 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	Consultation 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 38: Fast Fault Current Injection - Asymmetrical Faults

Justification:

The DNO and TSO invoke the right to specify a requirement for asymmetrical current injection as above

Consultation Responses

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

Parameter	Parameter in RfG	Consultation 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	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 39: Post-Fault Active Power Recovery for PPMs

Justification

The proposal of parameters which specify the capability of post-fault active power recovery is in line with CC.S2.1.3.6 c) of the current Grid Code requirements.

Grid Code and section 7.12.3.2. of the Distribution Code.

Consultation Responses

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.

5.2.4.4 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 40 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	Consultation Proposal	Article Number	Type Applicability	Justification Code
Prioritisation requirements during FRT	Active/Reactive	Active	21.3.e	C and D PPMs	3

Table 40: Priority given to Active or Reactive Power Contribution

Justification

The Grid Code is silent on this requirement in respect of wind farm power stations. The choice of active considered a priority for the Northern Ireland transmission system and is consistent with Grid Code.

5.2.5 Additional Non-Mandatory Voltage Requirements

There is one remaining non-mandatory requirements detailed in the RfG. Table 41 below identifies the area. We do not intend to invoke this non-mandatory requirement at this time.

Requirement	Requirement in RfG	Consultation Proposal	Article Number	Type Applicability
Simultaneous overvoltage and underfrequency or simultaneous undervoltage and overfrequency	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 41: 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 Article 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	Consultation 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*	3

Table 42: Operation Following Tripping to House Load

Justification

As per today's Grid Code requirements, there is no requirement for PGMs to be capable of tripping to house load. Instead, under Grid Code CC.S1.1.1.4, each CDGU or CCGT installation must be capable of restarting without a connection to an external power supply.

However, under the RfG, Type C and D PGMs, with synchronization times of 15 minutes or more, must be capable tripping to house load. For the purpose of this consultation the only item being consulted on is the operation time following tripping to house load. The TSO is proposing 4 hours which aligns with the expected time that it would take to resynchronise to the transmission system, under the Power System Restoration Plan.

Consultation Responses

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

Your understanding is correct.

Submission 2

One respondent commented that the Grid Code does not currently have this requirement. They are concerned that PGM's may be exposed to this future requirement but that it requires a CBA. They further comment that they are concerned that the TSO may attempt to have this changed in the current Grid Code prior to the Network Code coming into force, and so skip the requirement for a CBA. They comment that this previously happened with RoCoF leaving the existing generators with huge bills and little recompense through any other revenue stream.

SO Comments

The intention with these proposals is to amend the Grid Code, post the implementation of the RfG.

It is not currently proposed or planned to retrospectively apply these requirements to the existing fleet of PGMs.

If any changes to the requirements for the existing PGMs will go through the normal Grid Code modification process.

5.4 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

5.4.1 Article 15.2.b: Manual, local measures where the automatic remote devices are out of service

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	Consultation 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 43: Time required to Achieve Set point when Automatic Remote Devices are Unavailable

Justification:

Under the current version of the WFPS Settings Schedule (section 6.4), if the remote control of a WFPS is lost, the WFPS must remain its pre-fault set point for 10 minutes, before shutting down to 0 MW within 1 minute.

The proposal is that one hour after automatic remote control has been lost, manual intervention must be taken to return the PGMs to the required setpoint. The proposal of 1 hour is intended to allow the operator a reasonable time to attend the PGM site.

Consultation Responses

Submission 1

Two respondents commented that the timeline of 1 hour to allow operator attend PGM site will be difficult to achieve. They further commented that there are many factors that need to be considered i.e. remoteness, weather, road & traffic conditions.

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 and 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.

5.4.2 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	Consultation 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	1

Table 44: Quality of Supplies Parameters to be Recorded

Justification:

Under Grid Code OC11.5, the TSO has the right to carry out monitoring at any time and involves the analysis of the output of the generation unit.

However, as station and/or generation unit configuration can vary between sites, as well as possible compatibility issues with existing equipment, the exact requirement of the fault recording equipment will need to be specified on a site specific basis.

5.4.3 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	Consultation 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	1

Table 45: Oscillation Trigger Detecting Poorly Damped Power Oscillations

Justification

Under the Metering Code, the event recorders can be specified by the TSO. While the high level functional requirements of these recorders are detailed in the Metering Code, the detailed implementation must be specified on a case by case due to:

- Variations in Generation/site configurations
- Compatibility with existing equipment

5.4.4 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	Consultation 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	15(6)(c)(iii)	C and D PGMs and offshore PPMs	2

Table 46: Simulation Model Provision

Justification

PC6 the Planning Data Requirements from Users 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 requirements in PC6 but with the inclusion of additional fields for the provision of the min and max short circuit levels in MVA.

Consultation Responses

Submission 1

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

As per the RfG, the requirement is for the RSO to include the min and max short circuit capacity at the connection point expressed in MVA. This does not form part of our document requirements as detailed in the existing PCA in Grid Code. Our proposal is to include the missing element of the RfG requirement.

5.4.5 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	Consultation Proposal	Article Number	Type Applicability	Justification Code
Earthing arrangement of the neutral-point	Not Specified	Site specific - Will be specified as a part of the connection agreement	15(6)(f)	C and D PGMs and offshore PPMs	1

Table 47: Neutral-point at the Network Side of Step Transformers

Justification:

The proposal is to retain the existing Grid Code requirement as detailed in CC.6.8.1 which states that the specification of a User's Apparatus shall meet the voltages which will be imposed on the Apparatus as a result of the method of Earthing of the Transmission System, as specified in the relevant Connection Agreement.

5.6.1 Additional Non-Mandatory Protection & Instrumentation Requirements

There are a number of additional areas with non-exhaustive parameters detailed in the RfG. Table 48 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 consultation.

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 48: Parameters to be agreed on a Case by Case basis

6. Conclusion

This concludes the joint submission of SONI and NIE Networks to the Utility Regulator 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

SONI and NIE Networks would now like to request the approval of the Utility Regulator 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.

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System Operator for Northern Ireland

By email to gridcode@soni.ltd.uk

Our Ref: EN01-005649

9 February 2018

Dear Sir,

Re: RES Limited Response - RfG Consultation on Parameter Selection – Northern 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

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Response by Energia to SONI Consultation

RfG Consultation on Parameter Selection – Northern Ireland

9th February 2018

1. Introduction

Energia welcomes the opportunity to respond to this SONI RfG Consultation on Parameter Selection – Northern Ireland. Energia has contributed significantly to Island of Ireland's renewable and traditional generation capacity over the past number of years. This has been achieved through our investment, development, contracting and trading activities with policy support from government. As such we are well placed to comment on these proposed changes.

Please see the attached appendix: ***Energia Consultation Response Template Northern Ireland*** for our detailed comments.

Theme	Sub-Theme	Document Heading Number
Frequency Theme	**Frequency ranges**	4.1.1.1
Frequency Theme	**Rate of Change of Frequency**	4.1.2.1
Frequency Theme	**Rate of Change of Frequency**	4.1.2.1
Frequency Theme	**Active Power Control**	4.1.3.1
Frequency Theme	**Active Power Control**	4.1.3.2
Frequency Theme	**Active Power Control**	4.1.3.3
Frequency Theme	**Active Power Control**	4.1.3.4
Frequency Theme	**Active Power Control**	4.1.3.4
Frequency Theme	**Active Power Control**	4.1.3.4
Frequency Theme	**Active Power Control**	4.1.3.5

Frequency Theme	**Active Power Control**	4.1.3.6
Frequency Theme	**Active Power Control**	4.1.3.6
Frequency Theme	**Frequency Modes**	4.1.4.2
Frequency Theme	**Frequency Modes**	4.1.4.2
Frequency Theme	**Frequency Modes**	4.1.4.3
Frequency Theme	**Frequency Modes**	4.1.4.4
Frequency Theme	**Frequency Modes**	4.1.4.5
Frequency Theme	**Frequency Modes**	4.1.4.5
Frequency Theme	**Frequency Modes**	4.1.4.6
Frequency Theme	**Frequency Modes**	4.1.4.6
Frequency Theme	**Frequency Modes**	4.1.4.6
Frequency Theme	**Frequency Modes**	4.1.4.6
Frequency Theme	**Frequency Modes**	4.1.4.6
Frequency Theme	**Frequency Modes**	4.1.4.7
Frequency Theme	**Frequency Modes**	4.1.4.7
Frequency Theme	**Frequency Modes**	4.1.4.7

Frequency Theme	**Frequency Modes**	4.1.4.7
Frequency Theme	**Non-Mandatory Frequency Requirements that we are not invoking at this time**	4.1.5
Frequency Theme	**Non-Mandatory Frequency Requirements that we are not invoking at this time**	4.1.5
Voltage Theme	**Automatic Disconnection Due to Voltage Level**	4.2.1.1
Voltage Theme	**Automatic Disconnection Due to Voltage Level**	4.2.1.1
Voltage Theme	**Automatic Disconnection Due to Voltage Level**	4.2.1.2
Voltage Theme	**Automatic Disconnection Due to Voltage Level**	4.2.1.2
Voltage Theme	**Reactive Power Capability for Type B PGMs**	4.2.2.1.1
Voltage Theme	**Reactive Power Capability for Type B PGMs**	4.2.2.1.1
Voltage Theme	**Reactive Power Capability for Type B PGMs**	4.2.2.1.1
Voltage Theme	**Reactive Power Capability for Type B PGMs**	4.2.2.1.1
Voltage Theme	**Reactive Power Capability for Type B PGMs**	4.2.2.1.1
Voltage Theme	**Reactive Power Capability for Type B PGMs**	4.2.2.1.1
Voltage Theme	**Reactive Power Capability for Type B PGMs**	4.2.2.1.1
Voltage Theme	**Reactive Power Capability for Type B PGMs**	4.2.2.1.1
Voltage Theme	**Reactive Power Capability for Type B PGMs**	4.2.2.1.2
Voltage Theme	**Reactive Power Capability for Type B PGMs**	4.2.2.1.2
Voltage Theme	**Reactive Power Capability for Type B PGMs**	4.2.2.1.2
Voltage Theme	**Reactive Power Capability for Type B PGMs**	4.2.2.1.2
Voltage Theme	**Reactive Power Capability for Type B PGMs**	4.2.2.1.2
Voltage Theme	**Reactive Power Capability for Type B PGMs**	4.2.2.1.2
Voltage Theme	**Reactive Power Capability for Type B PGMs**	4.2.2.1.2

Voltage Theme	**Reactive Power Capability for Type B PGMs**	4.2.2.1.2
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.1
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.1
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.1
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.1
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.1
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.1
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.1
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Parameter	Parameter in RfG
Frequency Ranges	48,5 Hz-49,0 Hz for a time to be specified by each TSO, but not less than 90 minutes
The maximum RoCoF for which the Power Generating Module (PGM) shall stay connected	Not Specified
The proposal for loss of mains protection	Not Specified
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 or below 49.5 Hz falling by a reduction rate of 10% of the maximum capacity at 50 Hz per 1 Hz frequency drop.
Ambient Conditions	Not Specified
Specify requirements for equipment to make this facility operable remotely for Type A	A right to specify
(i) Frequency Ranges and Time Delay	Non-specific
(ii) Maximum admissible gradient of increase in power	Non-specific
(iii) Allowing automatic connection	A right to not allow
Right to specify the requirements for further equipment to allow active power output to be remotely operated	To specify or not to specify

The period within which the adjusted active power setpoint must be reached	No range provided
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
Frequency threshold	Between 50.2- 50.5 Hz
Droop settings	Between 2-12 %
Automatic disconnection and reconnection of PGMs	Allow or do not allow
Actions in LFSM-O upon reaching minimum regulating level,	Choose between (i) continuing operation at this level; or (ii) further decreasing active power output
Frequency threshold	between 49.8 Hz and 49.5 Hz inclusive
Droop settings	2-12%
Active Power Range (ΔP/Pmax)	1.5-10%
Frequency Response Insensitivity (Δf)	10-30 mHz
Frequency Response Insensitivity (Δf/f)	0.02-0.06%
Frequency Response Deadband	0-500mHz
Droop	2-12%
Active power range	1.5-10%
Admissible initial time delay for activation of active power frequency response for PPMs	Less than 2 seconds
Maximum admissible choice of full activation time	30 seconds

Capability relating to the duration of provision of full active power frequency response	15-30 minutes
Shorter initial FSM response delay for PGMs without inertia	Not specified
Synthetic inertia capability for PPM	Not Specified
Minimum Voltage below which Module will automatic disconnect	Not specified
Maximum Voltage above which Module will automatic disconnect	Not specified
Minimum Voltage below which Module will automatic disconnect	Not specified
Maximum Voltage above which Module will automatic disconnect	Not specified
umin (Low Voltage)	0.875 pu
umax (Low Voltage)	1.1 pu
Qmin/Pmax (lead) (Low Voltage)	-0.5 pu
Qmax/Pmax (lag) (Low Voltage)	0.65 pu
umin (Below 110kV)	0.875 pu
umax (Below 110kV)	1.1 pu
Qmin/Pmax (lead) (Below 110kV)	-0.5 pu
Qmax/Pmax (lag) (Below 110kV)	0.65 pu
umin (Low Voltage)	0.875 pu
umax (Low Voltage)	1.1 pu
Qmin/Pmax (lead) (Low Voltage)	-0.5 pu
Qmax/Pmax (lag) (Low Voltage)	0.65 pu
umin (Below 110kV)	0.875 pu
umax (Below 110kV)	1.1 pu
Qmin/Pmax (lead) (Below 110kV)	-0.5 pu

Qmax/Pmax (lag) (Below 110kV)	0.65 pu
umin (110 kV)	0.875 p.u.
umax (110 kV)	1.1 p.u.
Qmin/Pmax (lead) (110 kV)	-0.5 p.u.
Qmax/Pmax (lag) (110 kV)	0.65 p.u.
umin (275 kV)	0.875 p.u.
umax (275 kV)	1.1 p.u.
Qmin/Pmax (lead) (275 kV)	-0.5 p.u.
Qmax/Pmax (lag) (275 kV)	0.65 p.u.
umin (400 kV)	0.875 p.u.
umax (400 kV)	1.1 p.u.
Qmin/Pmax (lead) (400 kV)	-0.5 p.u.
Qmax/Pmax (lag) (400 kV)	0.65 p.u.
umin (Below 110kV)	0.875 p.u.
umax (Below 110kV)	1.1 p.u.
Qmin/Pmax (import) (Below 110kV)	-0.5 p.u.
Qmax/Pmax (Export) (Below 110kV)	0.65 p.u.
Time to achieve target value	Not specified
umin (110 kV)	0.875 p.u.
umax (110 kV)	1.1 p.u.
Qmin/Pmax (lead) (110 kV)	-0.5 p.u.

Qmax/Pmax (lag) (110 kV)	0.65 p.u.
umin (275 kV)	0.875 p.u.
umax (275 kV)	1.1 p.u.
Qmin/Pmax (lead) (275 kV)	-0.5 p.u.
Qmax/Pmax (lead) (275 kV)	0.65 p.u.
umin (400 kV)	0.875 p.u.
umax (400 kV)	1.1 p.u.
Qmin/Pmax (lead) (400 kV)	-0.5 p.u.
Qmax/Pmax (lag) (400 kV)	0.65 p.u.
umin (Below 110kV)	0.875 p.u.
umax (Below 110kV)	1.1 p.u.
Qmin/Pmax (lead) (Below 110kV)	-0.5 p.u.
Qmax/Pmax (lag) (Below 110kV)	0.65 p.u.
pmin (110 - 400kV)	0.0 p.u.
pmax (110 - 400kV)	1.0 p.u.
Qmin/Pmax (lead) (110 - 400kV)	-0.5 p.u.

Qmax/Pmax (lag) (110 - 400kV)	0.65 p.u.
pmin (Below 110kV)	0.0 p.u.
pmax (Below 110kV)	1.0 p.u.
Qmin/Pmax (lead) (Below 110kV)	-0.5 p.u.
Qmax/Pmax (lag) (Below 110kV)	0.65 p.u.
Time to achieve target value [transmission connected]	Not specified
Time to achieve target value [distribution connected]	Not specified
Right to specify supplementary reactive power requirements when the connection point is remote	To specify or not to specify
Right to specify supplementary reactive power requirements when the connection point is remote	To specify or not to specify
t1 = time within which 90% of the change in reactive power is reached	1 – 5 sec
t2 = time within which 100% of the change in reactive power is reached	5 – 60 sec
Target power factor	Not specified
Time period to reach the set point	Not specified
Tolerance	Not specified
Power Threshold	Not specified
Uret	0.05-0.3
Uclear	0.7-0.9
Urec1	Uclear
Urec2	0.85-0.9 & >=Uclear
tclear	0.14-0.25
trec1	tclear

trec2	trec1-0.7
trec3	trec2-1.5
Uret	0.05-0.15
Uclear	Uret -0.15
Urec1	Uclear
Urec2	0.85
tclear	0.14-0.25
trec1	tclear
trec2	trec1
trec3	1.5-3.0
Uret	0
Uclear	0.25
Urec1	0.5-0.7
Urec2	0.85-0.9
tclear	0.14-0.25
trec1	tclear -0.45
trec2	trec1-0.7
trec3	trec2-1.5
Uret	0
Uclear	Uret
Urec1	Uclear
Urec2	0.85
tclear	0.14-0.25
trec1	tclear
trec2	trec1

trec3	1.5-3.0
Voltage threshold for fast fault current injection	Not specified
End of the voltage deviation	Not specified
the characteristics of the fast fault current, including the time domain for measuring the voltage deviation and fast fault current	Not specified
the timing and accuracy of the fast fault current, which may include several stages during a fault and after its clearance	Not specified
Voltage threshold for fast fault current injection	Not specified
the characteristics of the fast fault current, including the time domain for measuring the voltage deviation and fast fault current	Not specified
the timing and accuracy of the fast fault current, which may include several stages during a fault and after its clearance	Not specified
when the post-fault active power recovery begins, based on a voltage criterion	Not specified
maximum allowed time for active power recovery	Not specified
magnitude and accuracy for active power recovery	Not specified
Prioritisation requirements during FRT	Active/Reactive
Simultaneous overvoltage and underfrequency or simultaneous undervoltage and overfrequency	Do we want to expertise the right to specify this non-mandatory RfG?
Operation Following Tripping to House Load	Not Specified
Time required to achieve setpoint when automatic remote devices are unavailable	Not Specified
Quality of supplies parameters to be recorded.	Not Specified

oscillation trigger detecting poorly damped power oscillations.	Not Specified
Model Provision	Not Specified
Earthing arrangement of the neutral-point	Not Specified
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
Electrical Protection Schemes and settings: Agreement and coordination between the RSO and the PGFO	Protection schemes and settings
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
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
Agreement between the PGFO and the RSO (DSO or TSO), in coordination with the TSO.	
Instrumentation: Protocols for recorded data	Protocols for recorded data
Agreement between PGFO, the RSO and the relevant TSO	
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
Synchronisation: Agreement between the RSO and the PGFO	Settings of the synchronisation devices

Angular stability under fault conditions: Agreement between the TSO and PGFO	Agreement for technical capabilities of the power generating module to aid angular stability.

Consultation Proposal	Article Number
90 Minutes	13.1.a.(i)
1 Hz/s over 500ms window	13.1.b
is 1 Hz/Sec with a 500ms delay.	13.1.b
below 49 Hz falling by a reduction rate of 2% of the maximum capacity at 50 Hz per 1 Hz frequency drop	13.4 (a)
10°C, 70% relative humidity and 1013 hPa for gas fired turbine generators	13.5
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
47 Hz to 50.1 Hz with a five minute delay	13.7
10% of Pmax per minute	13.7
Allow automatic connection for Type A & B Do not allow automatic connection for Type C	13.7
RSO to specify for Type B generators; in due time for plant design.	14.2 (b)

PPM controllable generation The Active power set point and the time to achieve this is determined by the TSO , however following shut down a PPM must commence active power export within 90secs WFPS setting schedule 6.11 SPGM dispatchable generation Active power set point and time to achieve the set point is given via TSO dispatch instructions in accordance with SDC2. Minimum ramp rates and start-up times specified in CC.S1.3.7 & CC.S1.2.3.4	15.2 (a)
PPM controllable generation. Active power output to be within 3% of set point (based on RC) Time to achieve set point within ±10 seconds of target time. (See WFPS Setting Schedule 6.1) SPGM dispatchable generation Tolerance bands for dispatch instructions is specified in OC11 Part B	15.2 (a)
50.2 Hz	13.2(a)
Machines should be capable of operating in the range 2-12%. The default setting is 4%	13.2(a)
Do not allow	13.2 (b)
(ii) further decreasing active power output	13.2 (f)
49.5 Hz	15.2 (c)
Default is 4% unless otherwise specified by the TSO on a site specific basis	15.2 (c)
Not proposing a value at this time	15.2 (d) (i) and (ii)
15mHz*	15.2 (d) (i) and (ii)
0.03%	15.2 (d) (i) and (ii)
+/-15mHz*	15.2 (d) (i) and (ii)
Depends on gen type – default is 4%	15.2 (d) (i) and (ii)
10%	15.2 (d) (iii)
0s No time delays other than those inherent in the design of the frequency response system	15.2 (d) (iii)
15 seconds	15.2 (d) (iii)

20	15.2 (d) (v)
Not Mandatory – can be agreed on a case by case basis with System Services Contracts	15.2.d(iv)
Not Mandatory – can be agreed on a case by case basis with System Services Contracts	21(2)
Specificed at plant design stage	15.3
Specificed at plant design stage	15.3
Not Allowed	16.2.c
Not Allowed	16.2.c
0.94 pu	17.2 (a) and 20.2 (a)
1.1 pu	17.2 (a) and 20.2 (a)
-0.33 pu	17.2 (a) and 20.2 (a)
0.203 pu	17.2 (a) and 20.2 (a)
0.94 pu	17.2 (a) and 20.2 (a)
1.06 pu	17.2 (a) and 20.2 (a)
-0.33 pu	17.2 (a) and 20.2 (a)
0.203 pu	17.2 (a) and 20.2 (a)
0.94 pu	17.2 (a) and 20.2 (a)
1.1 pu	17.2 (a) and 20.2 (a)
-0.33 pu	17.2 (a) and 20.2 (a)
0.203 pu	17.2 (a) and 20.2 (a)
0.94 pu	17.2 (a) and 20.2 (a)
1.06 pu	17.2 (a) and 20.2 (a)
-0.33 pu	17.2 (a) and 20.2 (a)

0.203 pu	17.2 (a) and 20.2 (a)
0.9 pu	18.2.b (ii)
1.1 pu	18.2.b (ii)
-0.48 pu	18.2.b (ii)
0.6 pu	18.2.b (ii)
0.9 pu	18.2.b (ii)
1.1 pu	18.2.b (ii)
-0.48 pu	18.2.b (ii)
0.6 pu	18.2.b (ii)
0.875 pu	18.2.b (ii)
1.05 pu	18.2.b (ii)
-0.48pu	18.2.b (ii)
0.6 pu	18.2.b (ii)
0.94 pu	18.2.b (ii)
1.06 pu	18.2.b (ii)
-0.33 pu	18.2.b (ii)
0.33 pu	18.2.b (ii)
Without undue delay but at least within 120 seconds	18.2.b (iv)
0.9 p.u.	21.3.b (ii)
1.1 p.u.	21.3.b (ii)
-0.33 p.u.	21.3.b (ii)

0.33 p.u.	21.3.b (ii)
0.9 p.u.	21.3.b (ii)
1.1 p.u.	21.3.b (ii)
-0.33 p.u.	21.3.b (ii)
0.33 p.u.	21.3.b (ii)
0.875 p.u.	21.3.b (ii)
1.05 p.u.	21.3.b (ii)
-0.33 p.u.	21.3.b (ii)
0.33 p.u.	21.3.b (ii)
0.94 pu	21.3.b (ii)
1.06 pu	21.3.b (ii)
-0.33 pu	21.3.b (ii)
0.33 pu	21.3.b (ii)
0.12 p.u.	21.3.c (ii)
1.0 p.u.	21.3.c (ii)
-0.33 p.u.	21.3.c (ii)

0.33 p.u.	21.3.c (ii)
0.15 p.u.	21.3.c (ii)
1.0 p.u.	21.3.c (ii)
-0.33 p.u.	21.3.c (ii)
0.33 p.u.	21.3.c (ii)
Without delay but within 20 seconds	21.3.c.(iv)
Without delay but within 20 seconds	21.3.c.(iv)
RSOs reserve the right to specify	18.2.a
RSOs reserve the right to specify	21.3.a
1	21.3.d.(iv)
5	21.3.d.(iv)
site-specific	21.3.d.(vi)
5 seconds	21.3.d.(vi)
5%	21.3.d.(vi)
All Type D SPGMs	19.2.b.(v)
0.05	14.3.a & 16.3.a
0.7	14.3.a & 16.3.a
Uclear	14.3.a & 16.3.a
0.9	14.3.a & 16.3.a
0.15	14.3.a & 16.3.a
tclear	14.3.a & 16.3.a

0.45	14.3.a & 16.3.a
trec2	14.3.a & 16.3.a
0.15	14.3.a & 16.3.a
0.15	14.3.a & 16.3.a
Uclear	14.3.a & 16.3.a
0.85	14.3.a & 16.3.a
0.25	14.3.a & 16.3.a
tclear	14.3.a & 16.3.a
tclear	14.3.a & 16.3.a
2.9	14.3.a & 16.3.a
0	16.3.a
0.25	16.3.a
0.5	16.3.a
0.9	16.3.a
0.15	16.3.a
tclear	16.3.a
0.45	16.3.a
trec2	16.3.a
0	16.3.a
Uret	16.3.a
Uclear	16.3.a
0.85	16.3.a
0.15	16.3.a
tclear	16.3.a
tclear	16.3.a

2.9	16.3.a
During voltage dips i.e. when the voltage is below 0.9 p.u.	20.2.b
Once the voltage has recovered to within normal operating voltage range	20.2.b
Reactive current should be provided for the duration of the voltage deviation within the rating of the PPM	20.2.b
Rise Time no greater than 100ms and a Settling Time no greater than 300ms.	20.2.b
During voltage dips i.e. when the voltage is below 0.9 p.u.	20.2.b
Reactive current should be provided for the duration of the voltage deviation within the rating of the PPM	20.2.b
Rise Time no greater than 100ms and a Settling Time no greater than 300ms.	20.2.b
un< 0.9 p.u.	20.3.a
500ms/1s	20.3.a
90%	20.3.a
Active	21.3.e
Not invoking	16(02)(a)(ii)
4 hours	15.5.c.iii
1 hour	15(2)(b)
Site Specific	15(6)(b)(i)

Site Specific	15(6)(b)(iii)
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)
Site specific - Will be specified as a part of the connection agreement	15(6)(f)
Case by case basis	14.5.a
Case by case basis	14.5.b
Case by case basis	15.6.a
Case by case basis	15.6.b(ii)
Case by case basis	15.6.b(ii)
Case by case basis	15.6.b(iv)
Case by case basis	15.6.b(iv)
Case by case basis	15.6.d
Case by case basis	16.4

Case by case basis	19.3

Type Applicability	Justification Code	Parameter or Requirement
A, B, C, D PGMs and Offshore PPMs	2	parameter
A, B, C and D PGMs and Offshore PPMs	1	parameter
A, B, C and D and Offshore PPMs	1	parameter
A, B, C and D PGMs	3	parameter
Gas-fired SPGMs (A, B, C and D).	3	parameter
A PGMs	3	requirement
A, B, and C PGMs	1	parameter
A, B and C PGMs	1	parameter
A, B and C PGMs	1	parameter
B PGMs	3	requirement

C and D PGMs	1	parameter
C and D PGMs	3	parameter
A, B, C and D PGMs & offshore PPMs	2	parameter
A, B, C and D PGMs & offshore PPMs	2	parameter
A PGMs	3	requirement
A, B, C and D PGMs & offshore PPMs	1	requirement
C and D PGMs & offshore PPMs	1	parameter
C and D PGMs & offshore PPMs	1	parameter
C and D PGMs & offshore PPMs	1	parameter
C and D PGMs & offshore PPMs	3	parameter
C and D PGMs & offshore PPMs	3	parameter
C and D PGMs& offshore PPMs	3	parameter
C and D PGMs & offshore PPMs	1	parameter
C and D PGMs & offshore PPMs	3	parameter
C and D PGMs & offshore PPMs	3	parameter
C and D PGMs & offshore PPMs	3	parameter

C and D PGMs & offshore PPMs	3	parameter
Type A, B, C and D PGMs and offshore PPMs	N/A	requirement
C and D PPMs	N/A	requirement
C (PPM)	1	parameter
C PGMs	1	parameter
D PGMs	3	parameter
D PGMs	3	parameter
B	1	parameter
B	1	parameter
B	1	parameter
B	1	parameter
B	1	parameter
B	1	parameter
B	1	parameter
B	1	parameter
B	1	parameter
B	1	parameter
B	1	parameter
B	1	parameter
B	1	parameter
B	1	parameter
B	1	parameter

B	1	parameter
D SPGMs	1	parameter
D SPGMs	1	parameter
D SPGMs	3	parameter
D SPGMs	3	parameter
D SPGMs	1	parameter
D SPGMs	1	parameter
D SPGMs	3	parameter
D SPGMs	3	parameter
D SPGMs	3	parameter
D SPGMs	3	parameter
D SPGMs	3	parameter
D SPGMs	3	parameter
C and D SPGMs	1	parameter
C and D SPGMs	1	parameter
C and D SPGMs	1	parameter
C and D SPGMs	1	parameter
C and D SPGMs	3	parameter
D PPMs	1	parameter
D PPMs	1	parameter
D PPMs	1	parameter

D PPMs	1	parameter
D PPMs	1	parameter
D PPMs	1	parameter
D PPMs	1	parameter
D PPMs	1	parameter
D PPMs	3	parameter
D PPMs	3	parameter
D PPMs	1	parameter
D PPMs	1	parameter
C and D PPM	1	parameter
C and D PPM	1	parameter
C and D PPM	1	parameter
C and D PPM	1	parameter
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C and D PPM	1	parameter
C and D PPM	1	parameter
C and D PPM	1	parameter
C and D PPM	1	parameter
C and D SPGM	3	parameter
C and D SPGM	3	parameter
Type C and D SPGMs	1	requirement
Type C and D PPMs	1	requirement
C and D PGMs	1	parameter
C and D PGMs	1	parameter
C and D PGMs	3	parameter
C and D PGMs	3	parameter
C and D PGMs	3	parameter
D SPGMs	2	parameter
B, C, D SPGMs	3	parameter
B, C, D SPGMs	3	parameter
B, C, D SPGMs	3	parameter
B, C, D SPGMs	3	parameter
B, C, D SPGMs	3	parameter
B, C, D SPGMs	3	parameter

B, C, D SPGMs	3	parameter
B, C, D SPGMs	3	parameter
B, C, D PPMs and Offshore PPMs	3	parameter
B, C, D PPMs and Offshore PPMs	3	parameter
B, C, D PPMs and Offshore PPMs	3	parameter
B, C, D PPMs and Offshore PPMs	3	parameter
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B, C, D PPMs and Offshore PPMs	3	parameter
D SPGMs	3	parameter
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D SPGMs	3	parameter
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D SPGMs	3	parameter
D PPMs	1	parameter
D PPMs	1	parameter
D PPMs	1	parameter
D PPMs	1	parameter
D PPMs	1	parameter
D PPMs	1	parameter
D PPMs	1	parameter

D PPMs	1	parameter
B, C and D PPMs	1	parameter
B, C and D PPMs	1	parameter
B, C and D PPMs	1	parameter
B, C and D PPMs	2	parameter
B, C and D PPMs	1	parameter
B, C and D PPMs	1	parameter
B, C and D PPMs	2	parameter
B, C and D PPMs and Offshore PPMs	1	parameter
B, C and D PPMs and Offshore PPMs	1	parameter
B, C and D PPMs and Offshore PPMs	1	parameter
C and D PPMs and Offshore PPMs	3	parameter
Type A, B, C and D PGMs		requirement
C and D PGMs and Offshore PPMs with a minimum re-synchronisation time greater than 15 minutes*	3	parameter
B, C and D PGMs	3	parameter
C and D PGMs and Offshore PPMs	1	requirement

C and D PGMs and Offshore PPMs	1	parameter
C and D PGMs and Offshore PPMs	2	requirement
C and D PGMs and Offshore PPMs	1	parameter
B,C,D PGMs and Offshore PPMs	N/A	parameter
B,C,D PGMs and Offshore PPMs	N/A	parameter
C.D PGMs and Offshore PPMs	N/A	parameter
C, D PGMs and Offshore PPMs	N/A	parameter
C, D PGMs and Offshore PPMs	N/A	parameter
C, D PGMs and Offshore PPMs	N/A	parameter
C, D PGMs and Offshore PPMs	N/A	parameter
C, D PGMs and Offshore PPMs	N/A	parameter
D PGMs and Offshore PPMs	N/A	parameter

D SPGM	N/A	parameter

Comment
The NI Grid Code has 60 minutes not 90 minutes and means that PGM's are exposed to future requirements albeit requires a CBA. However the concern remains that the TSO may attempt to have this changed in the current Grid Code prior to the Network Code coming into force, and so skip the requirement for a CBA as previously happened with RoCoF leaving the existing generators with significant costs and little recompense through any other revenue stream.
There are already existing PGM's non compliant with the current Grid Code RoCoF Modification because the existing standards were changed without proper investigation prior to having the RA approval. This process did not follow the CBA set out in the Network Code and has not provided generators with an appropriate revenue stream for this work.
Comment as above.
The existing PGM's are not compliant with this as they met the System requirements in the past, any modification to comply with this would be an OEM investigation and investment that would be subject to the Cost Benefit procedure outlined in the Network Code. However the concern remains that the TSO may attempt to have this changed in the current Grid Code prior to the Network Code coming into force, and so skip the requirement for a CBA as previously happened with RoCoF leaving the existing generators with huge bills and little recompense through any other revenue stream.
As above
Not applicable to PPB
The Automatic connection of type A,B,&C PGM's at these Frequency levels may affect the performance of other PGM's DS3 reserve and ramping products with contracted responses to a System Frequency event or even dispatch. This could expose them to Financial pe penalities under DS3 (for a 1MW deviation) as well as exposure through the Balancing Market. There needs to be a tolerance on DS3 performance to allow for this.
As Above
As Above
As Above

As Above
As Above
Currently this is agreeded between the PGM Owner and the TSO, we assume this is now fixed to 50.2Hz and is not negotiable.
NI Grid Code is 2-20%. We have concerns over the DS3 proposal to have PGM's with constantly dispatchable droop and a 10 Step response to Frequency movements and how this will interplay with others on the system and therefore affect the response of other units.

Agree with this proposal

Agree with this proposal
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Not applicable to PPB
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Not applicable to PPB
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Agree with this proposal
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Agree with this proposal

Agree with this proposal
Not applicable to PPB
Not applicable to PPB
Not applicable to PPB
Not applicable to PPB
Agree with this proposal
Agree with this proposal
TSO stated at the workshop there is no concern now but maybe in the future
TSO stated at the workshop there is no concern now but maybe in the future
Agree with this proposal
Agree with this proposal
Agree with this proposal
Agree with this proposal
Agree with this proposal
The TSO has stated that the requirement to fit a PPS is due to the generation profile on the System , these connections have been allowed by the TSO so this equipment should be funded by the TSO.
Not applicable
Not applicable
Not applicable
Not applicable
Not applicable
Not applicable

Not applicable
Not applicable
Not applicable
Not applicable
Not applicable
Not applicable
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Agree with this proposal
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Agree with this proposal
TSO has indicated that this is in line with NI Grid code connection conditions.
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Agree with this proposal
Agree with this proposal
As the NI Grid Code does not have this requirement it means that PGM's are exposed to future requirements albeit requires a CBA.. However the concern remains that the TSO may attempt to have this changed in the current Grid Code prior to the Network Code coming into force, and so skip the requirement for a CBA as previously happened with RoCoF leaving the existing generators with significant costs and little recompense through any other revenue stream.
There are many factors ~(i.e. remoteness, weather ,road & traffic conditions) that need to considered so a time isn't the only relevant parameter to measure against.
Current practice

Current practice
Current practice
Current practice
Agree with this proposal
Agree with this proposal
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Agree with this proposal

Power NI Energy Limited
Power Procurement Business (PPB)

SONI and NIE Networks' proposal for the general application of technical requirements in accordance with Articles 13-18 of Commission Regulation (EU) 2016/631 establishing a network code on requirements for grid connection of generators

Consultation Paper

20th December 2017

Updated with clarifications 17 January 2018

9 February 2018

power ni
Power Procurement Business

Introduction

Power NI Energy – Power Procurement Business ("PPB") welcomes the opportunity to respond to the consultation paper on the proposals for implementation of the Requirements for Generators Network Code.

General Comments

In addition to the comments provided in the form of the requested template for responses to this consultation we wish to draw out some general comments.

While this Network Code is designed to standardise generation unit parameters across Europe it must also be noted that the electricity system in Ireland and Northern Ireland is much smaller, has much higher levels of wind and has only two DC Interconnectors to the GB Network making it unique within Europe. As a consequence of these different conditions the existing stock of NI Grid Code compliant generators already connected were required to comply with very different standards and voltages than those proposed by the Network Code. These generation units have operated within the bounds of the current Grid Code for many years and the introduction of these new parameters must not be forced upon existing generators without the full rigor of Cost Benefit Analysis and consultation as described in the Network Code.

Additional Comments on the Consultation Paper

a) Page 5 – 1. Introduction

The TSO has added wording to further clarify the definition of existing PGMs '*whilst the RfG does not apply to an existing PGMs as per the above, should a PGM owner substantially modify their generation plant then certain requirements of the RfG will apply to that generation plant'*.

This does not define the meaning of 'substantially modify', and then leaves the application of 'certain requirements of the RfG' up to the TSO.

This loose terminology creates a lack of certainty as to the precise requirements and the circumstances that would trigger new obligations to comply with the Network Code. In other words, if an existing PGM, that has a connection and Generation License, wishes to enter into a DS3 Contract for its Ancillary Services to receive payment, the TSO has an additional set of criteria which can be reviewed and changed every quarter. The TSO can increase an existing requirement for one of these DS3 Products or introduce a new DS3 Product, thus requiring the PGM owner to modify its PGM to ensure its revenue stream remains. This new modification could be deemed 'substantial' by the TSO thereby requiring the PGM to invest further to meet the additional requirements of the Network Code to remain compliant or otherwise risk closure. It is a concern that despite the statement that RfG applies only to new generators, this assertion is meaningless when the DS3 Protocol document can be changed by the TSO, with RA approval, and could bring the Network Code criteria into scope for all existing PGMs if they wish to continue to be eligible to receive payments for modified DS3 services.

b) Page 8, section 3 of the RfG - Background

The statement is used that the RfG, '*Applies to only new generators'*.

The RfG will be the document used by new participants to understand the standards required to connect onto the Northern Ireland and ROI Transmission and Distribution Systems. Whilst this will provide all the requirements for connection to the network it is not explicit that there are further TSO System Ancillary Services (DS3) requirements. It is important that new participants are also made aware of the revenue streams that are not linked to the Network Code or Grid Code and that the generators plant and equipment must also satisfy, through additional testing, the DS3 criteria set out in the Protocol document and failure to do so may result in the TSO refusing to pay the PGM for any ancillary services. While the Network Code conditions for connection are fixed the TSO can change the DS3 Products both in terms of volume, technical capability and the payment rates every quarter creating a risk that new and existing participants need to design or modify their plant to capture this additional criteria.

c) Page 25 – Notes section of the consultation

It is also noted on page 25 the Notes section under Justification relating to 4.1.3.6 Article 15.2.a: there is a 'paragraph (b)' referred to however there is only a paragraph (a) on Page 24.

Final Comment

While the TSO/DSO is not suggesting existing generators become compliant with the Network Code we are concerned that over time, or indeed prior to the enforcement of the Network Code, the new requirements will be introduced, for example, as previously happened with RoCoF. There is no criteria specified to provide certainty and protection to existing PGMs that they will not be regularly required to meet new standards without there being appropriate Governance arrangements and with a requirement for appropriate Cost Benefit Analysis. This should include proper technical capability studies on the capability of existing plant and must not impose new retrofitting costs on PGMs that have previously been fully complaint, without providing adequate remuneration.

Please find attached our detailed comments using the response template provided.

Response by Energia to SONI Consultation

RfG Consultation on Parameter Selection – Northern Ireland

9th February 2018

1. Introduction

Energia welcomes the opportunity to respond to this SONI RfG Consultation on Parameter Selection – Northern Ireland. Energia has contributed significantly to Island of Ireland's renewable and traditional generation capacity over the past number of years. This has been achieved through our investment, development, contracting and trading activities with policy support from government. As such we are well placed to comment on these proposed changes.

Please see the attached appendix: ***Energia Consultation Response Template Northern Ireland*** for our detailed comments.

Theme	Sub-Theme	Document Heading No.	Article / Heading	Table Number	Parameter	Parameter in RfG	Consultation Proposal	Article Number	Type Applicability	Justification Code	Parameter or Requirement	GE Comments	Senvion Comments	RES Ltd Comments	Energia Comments	PPB Comments	Belfast Power Limited Comments	Solar Turbines Comment
Frequency Theme	**Frequency ranges**	4.1.1.1	Article 13.1 (a) (i): Frequency Ranges	1	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	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- in line with the RfG	Increase from 60 min in current Grid Code. To be confirmed with WTG OEM's	The NI Grid Code has 60 minutes not 90 minutes and means that PGM's are exposed to future requirements albeit requires a CBA. However the concern remains that the TSO may attempt to have this changed in the current Grid Code prior to the Network Code coming into force, and so skip the requirement for a CBA as previously happened with RoCoF leaving the existing generators with significant costs and little recompense through any other revenue stream.	The proposal for frequency ranges: "between 47-47.5 Hz for 20 seconds and between 51.5 -52 Hz for 60 minutes" is in our view not compliant with the RfG Art 13, 1 a) and table 1. Wider ranges only are allowed in agreement with the power plant owner. The rationale for this additional requirement to new power plants is not given.	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 conditions 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 than the ones stated in the RfG.
Frequency Theme	**Rate of Change of Frequency**	4.1.2.1	Article 13.1 (b): RoCoF	2	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			Agree- in line with the 'agreed in principle' Grid Code standard for RoCoF	No Change to current Grid Code requirements - Acceptable	There are already existing PGM's non compliant with the current Grid Code RoCoF Modification because the existing standards were changed without proper investigation prior to having the RA approval. This process did not follow the CBA set out in the Network Code and has not provided generators with an appropriate revenue stream for this work.	ok	
Frequency Theme	**Rate of Change of Frequency**	4.1.2.1	Article 13.1 (b): RoCoF	2	The proposal for loss of mains protection	Not Specified	is 1 Hz/Sec with a 500ms delay.	13.1.b	A, B, C and D and Offshore PPMs	1	parameter	Rate-of-change-of-frequency (ROCOF) measurements depends on the measurement duration, what windows is used for ROCOF loss of main protection. Frequency requirements shall be on an equality principle, it is recommended to harmonize frequency parameters at synchronous area level between EirGrid/ESB networks and NIE/ NIE network. The term loss of main in a Transmission context needs to be define further.		Agree- in line with the 'agreed in principle' Grid Code standard for RoCoF and Distribution Code requirement for >5MW MEC generation.	No Change to current Grid Code requirements - Acceptable	Comment as above.	ok	The proposal can be accepted only 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. Even in such a case the requirements 500ms seems to be a too long delay time for plant associated with an industrial process (e.g. cogeneration plant). Much shorte delay time would be recommended in such a case. Loss of main shall be based in this case on circuit breaker positioning or df/dt shall trip in a much shorter time. As an alternative logic combination of voltage and frequency protection function shall be adopted to detect separation from the grid
Frequency Theme	**Active Power Control**	4.1.3.1	Article 13.4.a: Admissible reduction from maximum output with falling frequency	3	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 or below 49.5 Hz falling by a reduction rate of 10% of the maximum capacity at 50 Hz per 1 Hz frequency drop.	below 49.5 Hz falling by a reduction rate of 2% of the maximum capacity at 50 Hz per 1 Hz frequency drop. This admissable reduction is allowed for Gas Turbines only due to Gas Turbine technology restrictions	13.4 (a)	A, B, C and D PGMs	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.		Agree	To be confirmed with WTG OEM's	The existing PGM's are not compliant with this as they met the System requirements in the past, any modification to comply with this would be an OEM investigation and investment that would be subject to the Cost Benefit procedure outlined in the Network Code. However the concern remains that the TSO may attempt to have this changed in the current Grid Code prior to the Network Code coming into force, and so skip the requirement for a CBA as previously happened with RoCoF leaving the existing generators with huge bills and little recompense through any other revenue stream.	Only the inherent (physical) behaviour of a generating unit is relevant for system stability. Any control actions during a frequency transient, to compensate for the inherent power loss, will be too late or even might further disturb the system e.g. when frequency is stabilised. Any requirement which does not consider the inherent behaviour would therefore exclude this technology from access to the system, disregarding all other benefits of this technology. For Synchronous PGMs it has to be taken into account that during a frequency drop (i.e. when the requirement is important) the inertia power response compensates the inherent power reduction to a certain amount (depending on the RoCoF). Compliance with this requirement is for certain technologies (in particular for Gas Turbines) only possible under certain ambient conditions – due to the fact that they show a strong relation between inherent power loss and ambient temperature. Hence, it does not make sense to link the requirement to a fixed ambient temperature. Furthermore a real test of compliance is not possible. Therefore, only a manufacturer statement based on calculations and simulations can be used as a prove of compliance. We therefore propose the following clear and simple approach: Require from SPGMs on a project-specific basis the inherent power vs. frequency characteristics (without any power compensation control measures) with ambient temperature as a variable parameter, to be used for system stability studies and design. This calculation can be done e.g. for a defined frequency over time curve.	The gas turbine technology output at falling frequency is non linear nor can be controlled since intrinsic to the generating unit itself. The 49 Hz, 2% power drop at the specified condition (10°C, 70&Humidity, 1013Pa) is not a realistic characteristic for any gas turbine (no matter which technology, nor if single or multiple shaft). An example of power behaviour for GT technology had been presented by EUTurbine since 2012 and explained and presented again during the 2nd and 3rd workshop on frequency paremeters organized by ENTSOE along 2017. https://www.entsoe.eu/news-events/events/Pages/Events/%E2%80%8B%E2%80%8B%E2%80%8B%E2%80%8B3rd-Workshop-on-the-connection-codes-frequency-parameters.aspx?EventWorkshopId=332 Since 2012 an example of possible power characteristics for GT behaviour has been presented. The requirements proposed here already exceeds the characteristics shown. As explained by EUTurbine this characteristics is even only an example since every gas turbine has its own characteritics, which are just an expected behaviour (no test can be carried out to prove the characteristics.. 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.
Frequency Theme	**Active Power Control**	4.1.3.2	Article 13.5: Admissible reduction from maximum output with falling frequency taking Account of Technical Capabilities of PGMs	4	Ambient Conditions	Not Specified	10°C, 70% relative humidity and 1013 hPa for gas fired turbine generators. This admissible reduction is allowed for Gas Turbines only due to Gas Turbine technology restrictions.	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.		No comment	N/A	As above	see 4.1.3.1	Art 13.5 is used for GT unit to complement art 13.4, by providing ambient condition and taking in consideration technical capabilities of the correspondent technology . This article had been created exactly to accomodate gas turbine technology, as you indicated in your clarification document). However, as explained above, the way it was defined is poorly reaching the goal, since every GT performs differently. 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. Note That: * This requirements is critical only at full power for GT characteristic. * There is no make good, the design is intrinsic to the all Gas Turbine category. * It cannot be tested, therefore it is difficult to define improvement and it does not drive competition. Compensative system are risky and someway useless: as a collateral effect they can lead to flame out and when existing they are slow acting logic, not in line with supporting the initial rocof. Compensative system bring the risk of flame-out, and as well cannot be tested, which we consider to be not a good trade for the requirments. See EUTurbine response of frequencies. http://www.euturbines.eu/cms/upload/publictaions/positions/EUTurbines_IGDs_response.pdf
Frequency Theme	**Active Power Control**	4.1.3.3	Article 13.6: Remote operation of facility to cease active power output	5	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 PGMs	3	requirement			Agree- would increase amount of generation under system operator control and reduce grid curtailment.	N/A to Energia (Type A < 0.01MW)	Not applicable to PPB	ok	
Frequency Theme	**Active Power Control**	4.1.3.4	Article 13.7: Automatic connection to the network	6	(i) Frequency Ranges and Time Delay	Non-specific	47 Hz to 50.1 Hz with a five minute delay	13.7	A, B, and C PGMs	1	parameter	There is mismatch between the proposed parameter in this excel and the document for consultation see Table 6.		Agree -consultation proposals is for 3 minute delay - short time delay below 50.2Hz faciliates availability of generation to support system in times of demand.	No Change to current Grid Code requirements - Acceptable	The Automatic connection of type A,B,&C PGM's at these Frequency levels may affect the performance of other PGM's DS3 reserve and ramping products with contracted responses to a System Frequency event or even dispatch. This could expose them to Financial pe penalties under DS3 (for a 1MW deviation) as well as exposure through the Balancing Market. There needs to be a tolerance on DS3 performance to allow for this.	ok	
Frequency Theme	**Active Power Control**	4.1.3.4	Article 13.7: Automatic connection to the network	6	(ii) Maximum admissible gradient of increase in power	Non-specific	10% of Pmax per minute	13.7	A, B and C PGMs	1	parameter			More clarity required- The 10% of Pmax proposal appears reasonable but the additional drafting relating to "otherwise" in the following quote is unclear and should be clarified - "10% of Pmax per minute after automatic reconnection. Otherwise power increase gradient limitation shall be in accordance with existing grid code ramp rate requirements e.g. CC.S2.1.3.7 and CC.S2.2.3.4."	No Change to current Grid Code requirements - Acceptable	As Above	ok	
Frequency Theme	**Active Power Control**	4.1.3.4	Article 13.7: Automatic connection to the network	6	(iii) Allowing automatic connection	A right to not allow	Allow automatic connection for Type A & B Do not allow automatic connection for Type C	13.7	A, B and C PGMs	1	parameter			Do not agree- If automatic reconnection is not allowed at all , Type C generation could be out of service for longer than is necessary. Propose that Type C also be allowed to reconnect automatically when frequency is less than 50.2Hz. *"SONI currently does not use automatic connection and would specify that it is not allowed in Northern Ireland for Type C PGMs*". This is misleading because at present SONI has no jurisdiction over automatic reconnection of generators which would be Type C PGMs. The existing practice is determined by NIEN in the D-Code and Connection Agreements. No justification for changing existing practise has been presented. *"Engineering Recommendations G59 & G83 settings allow PGMs of sizes Type A and Type B to automatically connect once the frequency is within normal operating ranges. This right will be retained under the RfG."*This is also misleading because G59/3 does not prohibit the automatic reconnection of generators which would be Type C PGMs. From G59/3 "*10.2.3 If automatic resetting of the protective equipment is used, there must be a time delay to ensure that healthy supply conditions exist for a minimum continuous period of 20s. Reset times may need to be co-ordinated where more than one Generating Plant is connected to the same feeder. The automatic reset must be inhibited for faults on the Generator's installation."* Also "*10.5.15 If automatic resetting of the protective equipment is used, as part of an auto-restore scheme for the Generating Plant, there must be a time delay to ensure that healthy supply conditions exist for a continuous period of at least 20 s. The automatic reset must be inhibited for faults on the Generator's installation. Staged timing may be required where more than one Generating Plant is connected to the same feeder. For Type Tested Generating Units the time delay is set at 20S*	No Change to current Grid Code requirements - Acceptable	As Above	ok	
Frequency Theme	**Active Power Control**	4.1.3.5	Article 14.2.b: Remote operation of power output	7	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; in due time for plant design.	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.	As Above	ok	To be defined prioritization of the different logics also when considering cogeneration plant. It is recommended to deal with specific agreement with generating plant where industrial facilities are depending on heat demand.
Frequency Theme	**Active Power Control**	4.1.3.6	Article 15.2.a: Achieving Active Power Set points	8	The period within which the adjusted active power setpoint must be reached	No range provided	PPM controllable generation The Active power set point and the time to achieve this is determined by the TSO , however following shut down a PPM must commence active power export within 90secs WFPS setting schedule 6.11 SPGM dispatchable generation Active power set point and time to achieve the set point is given via TSO dispatch instructions in accordance with SDC2. Minimum ramp rates and start-up times specified in CC.S1.3.7 & CC.S1.2.3.4	15.2 (a)	C and D PGMs	1	parameter		Can SONI comment on why the required time startup time for WFPS is shorter than 3 minutes required by EirGrid?	Agree* - in line with current WFPS Schedule requirement which requires that "Following Shutdown, upon removal of 'Emergency Action' mode by SONI, the WFPS should begin to export Active Power within 90 seconds" 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? *- perhaps such scenarios need to be recognised and noted.	No Change to current Grid Code requirements - Acceptable	As Above	ok	
Frequency Theme	**Active Power Control**	4.1.3.6	Article 15.2.a: Achieving Active Power Set points	8	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	PPM controllable generation. Active power output to be within 3% of set point (based on RC) Time to achieve set point within ±10 seconds of target time. (See WFPS Setting Schedule 6.1) SPGM dispatchable generation Tolerance bands for dispatch instructions is specified in OC11 Part B	15.2 (a)	C and D PGMs	3	parameter			Could be improved- 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.	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.	As Above	ok	
Frequency Theme	**Frequency Modes**	4.1.4.2	Article 13.2.a: LFSM-O Parameter Selection	9	Frequency threshold	Between 50.2- 50.5 Hz	50.2 Hz	13.2(a)	A, B, C and D PGMs & offshore PPMs	2	parameter			Agree - this is within the range of parameters in RfG current WFPS setting is 50.15Hz	To be confirmed with WTG OEM's	Currently this is agreed between the PGM Owner and the TSO, we assume this is now fixed to 50.2Hz and is not negotiable.	ok	
Frequency Theme	**Frequency Modes**	4.1.4.2	Article 13.2.a: LFSM-O Parameter Selection	9	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	2	parameter			Agree - this is in line with with existing requirements for FSM.	Acceptable (Less onorous than current Grid Code)	NI Grid Code is 2-20%. We have concerns over the DS3 proposal to have PGM's with constantly dispatchable droop and a 10 Step response to Frequency movements and how this will interplay with others on the system and there affect the response of other units.	ok	
Frequency Theme	**Frequency Modes**	4.1.4.3	Article 13.2.b: LFSM-O: Automatic disconnection and reconnection	10	Automatic disconnection and reconnection of PGMs	Allow or do not allow	Do not allow	13.2 (b)	A PGMs	3	requirement			No comment	Acceptable	Agree with this proposal	ok	
Frequency Theme	**Frequency Modes**	4.1.4.4	Article 13.2.f: LFSM-O: Actions at minimum regulating level	11	Actions in LFSM-O upon reaching minimum regulating level,	Choose between (i) continuing operation at this level; or (ii) further decreasing active power output	(ii) further decreasing active power output	13.2 (f)	A, B, C and D PGMs & offshore PPMs	1	requirement	There is mismatch between the proposed parameter in this excel and the document for consultation see Table 11.		Agree - this is in line with current grid code requirements	No Change to current Grid Code requirements - Acceptable	Agree with this proposal	Not every PGM is able to decrease the output easily below minimum regulating level. We propose to modify as follows: further decreasing active power output if technically possible, ensuring continuous stable operation.	

Frequency Theme	**Frequency Modes**	4.1.4.5	Article 15.2.c: LFSM U Parameter Selection	12	Frequency threshold	between 49.8 Hz and 49.5 Hz inclusive	49.5 Hz	15.2 (c)	C and D PGMs & offshore PPMs	1	parameter			Agree - this is the least likely to interfere with current FSM requirements	No Change to current Grid Code requirements - Acceptable	Agree with this proposal	ok	
Frequency Theme	**Frequency Modes**	4.1.4.5	Article 15.2.c: LFSM U Parameter Selection	12	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	parameter			Agree - this is the least likely to interfere with current FSM requirements	No Change to current Grid Code requirements - Acceptable	Agree with this proposal	ok	
Frequency Theme	**Frequency Modes**	4.1.4.6	Article 15.2.d.(i) and (ii): FSM Parameter Selection	13	Active Power Range (ΔP/Pmax)	1.5-10%	Not proposing a value at this time	15.2 (d) (i) and (ii)	C and D PGMs & offshore PPMs	1	parameter			No comment	No Change to current Grid Code requirements - Acceptable	Agree with this proposal	ok	
Frequency Theme	**Frequency Modes**	4.1.4.6	Article 15.2.d.(i) and (ii): FSM Parameter Selection	13	Frequency Response Insensitivity (Δf)	10-30 mHz	15mHz*	15.2 (d) (i) and (ii)	C and D PGMs & offshore PPMs	3	parameter			Agree - this is in line with Frequency Response Deadband in Grid Code	Acceptable as 15mHz remains maximum absolute value	Agree with this proposal	ok	
Frequency Theme	**Frequency Modes**	4.1.4.6	Article 15.2.d.(i) and (ii): FSM Parameter Selection	13	Frequency Response Insensitivity (Δf/f)	0.02-0.06%	0.03%	15.2 (d) (i) and (ii)	C and D PGMs & offshore PPMs	3	parameter			Agree - this is in line with Frequency Response Deadband in Grid Code	To be confirmed with WTG OEM's	Agree with this proposal	ok	
Frequency Theme	**Frequency Modes**	4.1.4.6	Article 15.2.d.(i) and (ii): FSM Parameter Selection	13	Frequency Response Deadband	0-500mHz	+/-15mHz*	15.2 (d) (i) and (ii)	C and D PGMs& offshore PPMs	3	parameter			Agree	To be confirmed with WTG OEM's	Agree with this proposal	ok	
Frequency Theme	**Frequency Modes**	4.1.4.6	Article 15.2.d.(i) and (ii): FSM Parameter Selection	13	Droop	2-12%	Depends on gen type – default is 4%	15.2 (d) (i) and (ii)	C and D PGMs & offshore PPMs	1	parameter			Agree, this in line with current grid code requirements	No Change to current Grid Code requirements - Acceptable	Agree with this proposal	ok	
Frequency Theme	**Frequency Modes**	4.1.4.7	Article 15.2.d.(iii): FSM: Step Change in Frequency	14	Active power range	1.5-10%	10%	15.2 (d) (iii)	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. 3.FSM parameters needs to be consulted further with O&M. System Ooeration Guide Line Title 5 (SOGL) Article 156.6 states that a single power generating unit is not allowed to cover more than 5% of the FCR of a synchronous area. SOGL needs to be taken into account when defining the parameter of FSM to cover the reference imbalance incident (% of largest in feed). 10% in 5s is nearly impossible to achieve for conventional CCGT.	As the intention is to retain the current arrangements can EirGrid please provide further clarity regarding the required active power frequency response for WFPS, ideally this would be in the form of additional guidance with example benchmark behaviour. Could EirGrid also provide further clarity on expectation regarding speed of frequency response when increasing from significant active power curtailment e.g. below 40% of Pmax and during periods of low wind speed.	More clarity required- as this appears to be inconsistent with the response required when the frequency deviation is sufficient to require the maximum response at that droop (delta F corresponding to delta P1 in RfG figure 5). We are of the view that this parameter is not the response required in 5 seconds (POR timescale). RfG requires a definition of a related time t2 to achieve delta P (RfG figure 6) and confusingly the TSO appears to have proposed 15 seconds below. Also 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?	To be confirmed with WTG OEM's	Agree with this proposal	It is common practice that the TSO defines a amount of reserve (as dP/Pmax in %), in order to allow a better definition and limitation of the governor free action. We do not see it as an error by ENTSO-E.	
Frequency Theme	**Frequency Modes**	4.1.4.7	Article 15.2.d.(iii): FSM: Step Change in Frequency	14	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	parameter		There will always be delays introduced by measurement equipment the controller cyle time and the operation of pitch motors, valves etc. A more realistic proposal would be 1 s. Ancillary services contracts to provide enhaced capability from technologies capable of very fast response (e.g. batteries) could be set up seperately.	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	Agree with this proposal	Being a control action, 0 s technicall is not achievable. Proposal: "no time delays other than those inherent in the design of the frequency response system, but not more than 2 s"	
Frequency Theme	**Frequency Modes**	4.1.4.7	Article 15.2.d.(iii): FSM: Step Change in Frequency	14	Maximum admissible choice of full activation time	30 seconds	15 seconds	15.2 (d) (iii)	C and D PGMs & offshore PPMs	3	parameter	1- There is mismatch between the proposed parameter in this excel and the document for consultation see Table 14. We note that the value in the excel template is in line with the final IGD on Frequency sensitive mode. 2-Frequency requirements shall be on an equality principle, it is recommended to harmonize frequency parameters at synchronous area level between EirGrid/ESB networks and NIE/ NIE network.		Clarity required- The consultation document states 5 seconds and not 15s. 5 seconds is in line with current primary operating reserve response time. 15 seconds is in line with current secondary operating reserve response time. We understand "*Maximum admissible choice of full activation time*" to be the time required to deliver Active Power Range propsed above (10%) . Also 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	Agree with this proposal	The proposal stipulates 5 seconds as full activation time, not 15 s. However, this short time will not be achievable for SPGM in free governor mode without limitation of the reserve (as dP/Pmax in %), pls. see above.	
Frequency Theme	**Frequency Modes**	4.1.4.7	Article 15.2.d.(iii): FSM: Step Change in Frequency	14	Capability relating to the duration of provision of full active power frequency response	15-30 minutes	20	15.2 (d) (v)	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.	To be confirmed with WTG OEM's	Agree with this proposal	ok	
Frequency Theme	**Non-Mandatory Frequency Requirements that we are not invoking at this time**	4.1.5	Non-Mandatory Frequency Requirements that we are not invoking at this time	15	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	N/A	requirement			Agree - agreement via System Services Contract means it is non-mandatory.	N/A	Agree with this proposal	ok	
Frequency Theme	**Non-Mandatory Frequency Requirements that we are not invoking at this time**	4.1.5	Non-Mandatory Frequency Requirements that we are not invoking at this time	15	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	N/A	requirement			Agree - agreement via System Services Contract means it is non-mandatory.	N/A	Agree with this proposal	ok	
Voltage Theme	**Automatic Disconnection Due to Voltage Level**	4.2.1.1	Article 15.3: Type C Automatic Disconnection Due to Voltage Level	16	Minimum Voltage below which Module will automatic disconnect	Not specified	Specificed at plant design stage	15.3	C (PPM)	1	parameter			More clarity required- We suggest specification along the lines of "S*pecified at plant design stage to coordinate with G59 or G83 as the case may be*" Otherwise the TSOs intent will be lost and inappropriate interpretations may be applied	No Change to current Grid Code requirements - Acceptable	Agree with this proposal		
Voltage Theme	**Automatic Disconnection Due to Voltage Level**	4.2.1.1	Article 15.3: Type C Automatic Disconnection Due to Voltage Level	16	Maximum Voltage above which Module will automatic disconnect	Not specified	Specificed at plant design stage	15.3	C PGMs	1	parameter			More clarity required-We suggest specification along the lines of "S*pecified at plant design stage to coordinate with G59 or G83 as the case may be*" Otherwise the TSOs intent will be lost and inappropriate interpretations may be applied	No Change to current Grid Code requirements - Acceptable	Not applicable to PPB		
Voltage Theme	**Automatic Disconnection Due to Voltage Level**	4.2.1.2	Article 16.2.c: Type D Automatic Disconnection Due to Voltage Level	17	Minimum Voltage below which Module will automatic disconnect	Not specified	Not Allowed	16.2.c	D PGMs	3	parameter			More clarity required-Is "Not Allowed" consistent with G59 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.	Not specified in existing Grid Code - Acceptable	Agree with this proposal	Equipment design has high and low voltage limits according to applicable design rules, these should be considered here.	Maybe it has to be better explained the expectation of the requirements and the intended proposal. Low voltage protection will be present (what if transmission system disconnect from the generating plant?). Protection settings have to be set. As a minimum values above the min voltage where the generating shall continuously operate. If this is related to the protection between the S/S and the MV system where the generating unit is different, please neglect this comment. In this case the values for the distribution applies. For industrial system, RfG art 6.3 shall be considered.
Voltage Theme	**Automatic Disconnection Due to Voltage Level**	4.2.1.2	Article 16.2.c: Type D Automatic Disconnection Due to Voltage Level	17	Maximum Voltage above which Module will automatic disconnect	Not specified	Not Allowed	16.2.c	D PGMs	3	parameter			More clarity required-Is "Not Allowed" consistent with G59 protection which disconnects generator abovea certain voltage? Generators must have the right to disconnect if voltages exceed planning limits and may cause equipment damange.	Not specified in existing Grid Code - Acceptable	Agree with this proposal	Equipment design has high and low voltage limits according to applicable design rules, these should be considered here.	Maybe it has to be better explained the expectation of the requirements and the intended proposal. High voltage protection will be present (what if transmission system disconnect from the generating plant?). Protection settings have to be set. As a minimum values above the max voltage where the generating shall continuously operate. If this is related to the protection between the S/S and the MV system where the generating unit is different, please neglect this comment. In this case the values for the distribution applies. For industrial system, RfG art 6.3 shall be considered.
Voltage Theme	**Reactive Power Capability for Type B PGMs**	4.2.2.1.1	Article 17.2.a: Reactive Power capability for Type B SPGMs	18	umin (Low Voltage)	0.875 pu	0.94 pu	17.2 (a) and 20.2 (a)	B	1	parameter			Agree	No Change to current Grid Code requirements - Acceptable	Not applicable to PPB		General Note. The RfG does not prevent the use of non rectangular shape. Different shapes had been proposed to accomodate operational point that are unlikely to happen such as overexcitation at high voltage and underexcitation at low voltage. It would recommandable to adopt such characteristics to ease the requirements, especially for synchornous generator. An example can be found in National Grid Code CC.6.3.4 and here reported. But also see VDE AR-4120, where different possible "internal" shapes are provided to be chosen by the operator to adopt.
Voltage Theme	**Reactive Power Capability for Type B PGMs**	4.2.2.1.1	Article 17.2.a: Reactive Power capability for Type B SPGMs	18	umax (Low Voltage)	1.1 pu	1.1 pu	17.2 (a) and 20.2 (a)	B	1	parameter			Agree	No Change to current Grid Code requirements - Acceptable	Not applicable to PPB		See Comment above
Voltage Theme	**Reactive Power Capability for Type B PGMs**	4.2.2.1.1	Article 17.2.a: Reactive Power capability for Type B SPGMs	18	Qmin/Pmax (lead) (Low Voltage)	-0.5 pu	-0.33 pu	17.2 (a) and 20.2 (a)	B	1	parameter			No comment	No Change to current Grid Code requirements - Acceptable	Not applicable to PPB		Reading the indication in the Parameter4Consultation document, the understanding is that generator is requested with power factor 0.95
Voltage Theme	**Reactive Power Capability for Type B PGMs**	4.2.2.1.1	Article 17.2.a: Reactive Power capability for Type B SPGMs	18	Qmax/Pmax (lag) (Low Voltage)	0.65 pu	0.203 pu	17.2 (a) and 20.2 (a)	B	1	parameter			No comment	No Change to current Grid Code requirements - Acceptable	Not applicable to PPB		Reading the indication in the Parameter4Consultation document, the understanding is that generator is requested with power factor 0.98
Voltage Theme	**Reactive Power Capability for Type B PGMs**	4.2.2.1.1	Article 17.2.a: Reactive Power capability for Type B SPGMs	18	umin (Below 110kV)	0.875 pu	0.94 pu	17.2 (a) and 20.2 (a)	B	1	parameter			No comment	No Change to current Grid Code requirements - Acceptable	Not applicable to PPB		General Note. The RfG does not prevent the use of non rectangular shape. Different shapes had been proposed to accomodate operational point that are unlikely to happen such as overexcitation at high voltage and underexcitation at low voltage. It would recommandable to adopt such characteristics to ease the requirements, especially for synchornous generator. An example can be found in National Grid Code CC.6.3.4 and here reported. But also see VDE AR-4120, where different possible "internal" shapes are provided to be chosen by the operator to adopt.
Voltage Theme	**Reactive Power Capability for Type B PGMs**	4.2.2.1.1	Article 17.2.a: Reactive Power capability for Type B SPGMs	18	umax (Below 110kV)	1.1 pu	1.06 pu	17.2 (a) and 20.2 (a)	B	1	parameter			No comment	No Change to current Grid Code requirements - Acceptable	Not applicable to PPB		See Comment above
Voltage Theme	**Reactive Power Capability for Type B PGMs**	4.2.2.1.1	Article 17.2.a: Reactive Power capability for Type B SPGMs	18	Qmin/Pmax (lead) (Below 110kV)	-0.5 pu	-0.33 pu	17.2 (a) and 20.2 (a)	B	1	parameter			No comment	No Change to current Grid Code requirements - Acceptable	Not applicable to PPB		Reading the indication in the Parameter4Consultation document, the understanding is that generator is requested with power factor 0.95
Voltage Theme	**Reactive Power Capability for Type B PGMs**	4.2.2.1.1	Article 17.2.a: Reactive Power capability for Type B SPGMs	18	Qmax/Pmax (lag) (Below 110kV)	0.65 pu	0.203 pu	17.2 (a) and 20.2 (a)	B	1	parameter			No comment	No Change to current Grid Code requirements - Acceptable	Not applicable to PPB		Reading the indication in the Parameter4Consultation document, the understanding is that generator is requested with power factor 0.98
Voltage Theme	**Reactive Power Capability for Type B PGMs**	4.2.2.1.2	Article 20.2.a: Reactive Power capability for Type B PPMs	19	umin (Low Voltage)	0.875 pu	0.94 pu	17.2 (a) and 20.2 (a)	B	1	parameter			Agree -line up with existing D-code	No Change to current Grid Code requirements - Acceptable	Not applicable to PPB		
Voltage Theme	**Reactive Power Capability for Type B PGMs**	4.2.2.1.2	Article 20.2.a: Reactive Power capability for Type B PPMs	19	umax (Low Voltage)	1.1 pu	1.1 pu	17.2 (a) and 20.2 (a)	B	1	parameter			Agree -line up with existing D-code	No Change to current Grid Code requirements - Acceptable	Not applicable to PPB		
Voltage Theme	**Reactive Power Capability for Type B PGMs**	4.2.2.1.2	Article 20.2.a: Reactive Power capability for Type B PPMs	19	Qmin/Pmax (lead) (Low Voltage)	-0.5 pu	-0.33 pu	17.2 (a) and 20.2 (a)	B	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 SONI /NIEN have chosen within the specified U and Q/Pmax coordinates. We assume a rectangle corresponding to these coordinates but this is not stated.	No Change to current Grid Code requirements - Acceptable	Not applicable to PPB		
Voltage Theme	**Reactive Power Capability for Type B PGMs**	4.2.2.1.2	Article 20.2.a: Reactive Power capability for Type B PPMs	19	Qmax/Pmax (lag) (Low Voltage)	0.65 pu	0.203 pu	17.2 (a) and 20.2 (a)	B	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 SONI /NIEN have chosen within the specified U and Q/Pmax coordinates. We assume a rectangle corresponding to these coordinates but this is not stated.	No Change to current Grid Code requirements - Acceptable	Not applicable to PPB		
Voltage Theme	**Reactive Power Capability for Type B PGMs**	4.2.2.1.2	Article 20.2.a: Reactive Power capability for Type B PPMs	19	umin (Below 110kV)	0.875 pu	0.94 pu	17.2 (a) and 20.2 (a)	B	1	parameter			Agree -line up with existing D-code	No Change to current Grid Code requirements - Acceptable	Not applicable to PPB		

Voltage Theme	**Reactive Power Capability for Type B PGMs**	4.2.2.1.2	Article 20.2.a: Reactive Power capability for Type B PPMs	19	umax (Below 110kV)	1.1 pu	1.06 pu	17.2 (a) and 20.2 (a)	B	1	parameter			Agree -appears reasonable	No Change to current Grid Code requirements - Acceptable	Not applicable to PPB		
Voltage Theme	**Reactive Power Capability for Type B PGMs**	4.2.2.1.2	Article 20.2.a: Reactive Power capability for Type B PPMs	19	Qmin/Pmax (lead) (Below 110kV)	-0.5 pu	-0.33 pu	17.2 (a) and 20.2 (a)	B	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 SONI /NIEN have chosen within the specified U and Q/Pmax coordinates. We assume a rectangle corresponding to these coordinates but this is not stated.	No Change to current Grid Code requirements - Acceptable	Not applicable to PPB		
Voltage Theme	**Reactive Power Capability for Type B PGMs**	4.2.2.1.2	Article 20.2.a: Reactive Power capability for Type B PPMs	19	Qmax/Pmax (lag) (Below 110kV)	0.65 pu	0.203 pu	17.2 (a) and 20.2 (a)	B	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 SONI /NIEN have chosen within the specified U and Q/Pmax coordinates. We assume a rectangle corresponding to these coordinates but this is not stated.	No Change to current Grid Code requirements - Acceptable	Not applicable to PPB		
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.1	Article 18.2.b.(i): SPGM: Parameters required for U-Q/Pmax Profiles	20	umin (110 kV)	0.875 p.u.	0.9 pu	18.2.b (ii)	D SPGMs	1	parameter	1-Requirements were imposed at generator terminals (0.95 under excited to 0.8 overexcited), now they are imposed at the HV terminals of the Generator Step-up Transformer. Would the requirement on the generator power factor be removed after Article 18.2.b (i) RfG implementation? 2-What assumption was used for the Generator Step-up Transformer sizing/impedance/number of taps and the Unit Auxiliary Transformer Var loading for a range of 10MW generating unit and above (upto750MVA) to reach the proposed projected at PCC inner parameter envelope? A detail industry survey shall be conducted to ensure that the requirement is achievable with standard design practice. 3-In our opinion, the under excited (leading) proposal of -0.5 (Qmin/Pmax) and 0.9 voltage and overexcited (lagging) proposal of 0.52 (Qmax/Pmax) and 1.1 voltage can have a huge impact in the generator size, min and max voltage at generator terminal and GSUT size (and price), it is also worth to note that the generator is unlikely to operate at leading power factor with low voltage at Point of Connection (similarly, unlikely to be at 0.53 lagging and at Grid Voltage at 1.1). The shape of the inner envelope shall take this into account and be translated to a more appropriate shape like a parallelogram one. 4-V, Q/Pmax capability at part load (Pgen less than Pmax, 50% as actual Grid code) are missing from the consultation paper. 5- Define Pmax Maximum Capacity for CCGT multiple generator configuration whether this is at unit or plant level and measured at generator terminal or point of connection (less house load and GSUT loading). 6- Umin (400kV) =0.875 does not align with the RfG voltage ranges which the PGM shall stay connected and operate normally, see table 6.1 in Article 16 where it says umin=0.9. 7-A real test of compliance at extreme Grid voltage is not possible (0.9 p.u or 1.1 voltage). Clarify how this will be tested and what proof of compliance is required to fulfil this requirement. 8-Requirements shall be on an equality principle, it's recommended to harmonize those parameters at synchronous area level between EirGrid and NIE.		No comment	No Change to current Grid Code requirements - Acceptable	Agree with this proposal		General Note. The RfG does not prevent the use of non rectangular shape. Different shapes had been proposed to accomodate operational point that are unlikely to happen such as overexcitation at high voltage and underexcitation at low voltage. It would recommandable to adopt such characteristics to ease the requirements, especially for synchornous generator. An example can be found in National Grid Code CC.6.3.4 and here reported. But also see VDE AR-4120, where different possible "internal" shapes are provided to be chosen by the operator to adopt.
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.1	Article 18.2.b.(i): SPGM: Parameters required for U-Q/Pmax Profiles	20	umax (110 kV)	1.1 p.u.	1.1 pu	18.2.b (ii)	D SPGMs	1	parameter			No comment	No Change to current Grid Code requirements - Acceptable	Agree with this proposal		See above Comment
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.1	Article 18.2.b.(i): SPGM: Parameters required for U-Q/Pmax Profiles	20	Qmin/Pmax (lead) (110 kV)	-0.5 p.u.	-0.48 pu	18.2.b (ii)	D SPGMs	3	parameter			No comment	N/A	Agree with this proposal	Max. leading operation (Q_{min}/P_{max} (lead)=-0,48) at GSU HV terminals shall not be required for HV voltages $U<U_{rated.}$ Max. leading (underexcited) operation of the generator at lowest grid voltage level is technically not required.	Reading the indication in the Parameter4Consultation document, the understanding is that generator is requested with power factor 0.8
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.1	Article 18.2.b.(i): SPGM: Parameters required for U-Q/Pmax Profiles	20	Qmax/Pmax (lag) (110 kV)	0.65 p.u.	0.6 pu	18.2.b (ii)	D SPGMs	3	parameter			No comment	N/A	Agree with this proposal	Max. lagging operation (Qmax/Pmax (lag)=0,60) at GSU HV terminals shall not be required for HV voltages $U>1,05U_{rated}$ Max. lagging (overexcited) operation of the generator at highest grid voltage level is technically not required.	Reading the indication in the Parameter4Consultation document, the understanding is that generator is requested with power factor 0.95
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.1	Article 18.2.b.(i): SPGM: Parameters required for U-Q/Pmax Profiles	20	umin (275 kV)	0.875 p.u.	0.9 pu	18.2.b (ii)	D SPGMs	1	parameter			No comment	No Change to current Grid Code requirements - Acceptable	Agree with this proposal		General Note. The RfG does not prevent the use of non rectangular shape. Different shapes had been proposed to accomodate operational point that are unlikely to happen such as overexcitation at high voltage and underexcitation at low voltage. It would recommandable to adopt such characteristics to ease the requirements, especially for synchornous generator. An example can be found in National Grid Code CC.6.3.4 and here reported. But also see VDE AR-4120, where different possible "internal" shapes are provided to be chosen by the operator to adopt.
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.1	Article 18.2.b.(i): SPGM: Parameters required for U-Q/Pmax Profiles	20	umax (275 kV)	1.1 p.u.	1.1 pu	18.2.b (ii)	D SPGMs	1	parameter			No comment	No Change to current Grid Code requirements - Acceptable	Agree with this proposal		See above Comment
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.1	Article 18.2.b.(i): SPGM: Parameters required for U-Q/Pmax Profiles	20	Qmin/Pmax (lead) (275 kV)	-0.5 p.u.	-0.48 pu	18.2.b (ii)	D SPGMs	3	parameter			No comment	N/A	Agree with this proposal	Max. leading operation (Q_{min}/P_{max} (lead)=-0,48) at GSU HV terminals shall not be required for HV voltages $U<U_{rated.}$ Max. leading (underexcited) operation of the generator at lowest grid voltage level is technically not required.	Reading the indication in the Parameter4Consultation document, the understanding is that generator is requested with power factor 0.8
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.1	Article 18.2.b.(i): SPGM: Parameters required for U-Q/Pmax Profiles	20	Qmax/Pmax (lag) (275 kV)	0.65 p.u.	0.6 pu	18.2.b (ii)	D SPGMs	3	parameter			No comment	N/A	Agree with this proposal	Max. lagging operation (Qmax/Pmax (lag)=0,60) at GSU HV terminals shall not be required for HV voltages $U>1,05U_{rated}$ Max. lagging (overexcited) operation of the generator at highest grid voltage level is technically not required.	Reading the indication in the Parameter4Consultation document, the understanding is that generator is requested with power factor 0.95
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.1	Article 18.2.b.(i): SPGM: Parameters required for U-Q/Pmax Profiles	20	umin (400 kV)	0.875 p.u.	0.875 pu	18.2.b (ii)	D SPGMs	3	parameter			No comment	N/A	Agree with this proposal		General Note. The RfG does not prevent the use of non rectangular shape. Different shapes had been proposed to accomodate operational point that are unlikely to happen such as overexcitation at high voltage and underexcitation at low voltage. It would recommandable to adopt such characteristics to ease the requirements, especially for synchornous generator. An example can be found in National Grid Code CC.6.3.4 and here reported. But also see VDE AR-4120, where different possible "internal" shapes are provided to be chosen by the operator to adopt.
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.1	Article 18.2.b.(i): SPGM: Parameters required for U-Q/Pmax Profiles	20	umax (400 kV)	1.1 p.u.	1.05 pu	18.2.b (ii)	D SPGMs	3	parameter			No comment	N/A	Agree with this proposal		See above Comment
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.1	Article 18.2.b.(i): SPGM: Parameters required for U-Q/Pmax Profiles	20	Qmin/Pmax (lead) (400 kV)	-0.5 p.u.	-0.48pu	18.2.b (ii)	D SPGMs	3	parameter			No comment	N/A	Agree with this proposal	Max. leading operation (Q_{min}/P_{max} (lead)=-0,48) at GSU HV terminals shall not be required for HV voltages $U<U_{rated.}$ Max. leading (underexcited) operation of the generator at lowest grid voltage level is technically not required.	Reading the indication in the Parameter4Consultation document, the understanding is that generator is requested with power factor 0.8
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.1	Article 18.2.b.(i): SPGM: Parameters required for U-Q/Pmax Profiles	20	Qmax/Pmax (lag) (400 kV)	0.65 p.u.	0.6 pu	18.2.b (ii)	D SPGMs	3	parameter			No comment	N/A	Agree with this proposal		Reading the indication in the Parameter4Consultation document, the understanding is that generator is requested with power factor 0.95
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.1	Article 18.2.b.(i): SPGM: Parameters required for U-Q/Pmax Profiles	21	umin (Below 110kV)	0.875 p.u.	0.94 pu	18.2.b (ii)	C and D SPGMs	1	parameter			No comment	No Change to current Grid Code requirements - Acceptable	Not applicable to PPB		General Note. The RfG does not prevent the use of non rectangular shape. Different shapes had been proposed to accomodate operational point that are unlikely to happen such as overexcitation at high voltage and underexcitation at low voltage. It would recommandable to adopt such characteristics to ease the requirements, especially for synchornous generator. An example can be found in National Grid Code CC.6.3.4 and here reported. But also see VDE AR-4120, where different possible "internal" shapes are provided to be chosen by the operator to adopt.
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.1	Article 18.2.b.(i): SPGM: Parameters required for U-Q/Pmax Profiles	21	umax (Below 110kV)	1.1 p.u.	1.06 pu	18.2.b (ii)	C and D SPGMs	1	parameter			No comment	No Change to current Grid Code requirements - Acceptable	Not applicable to PPB		See above Comment
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.1	Article 18.2.b.(i): SPGM: Parameters required for U-Q/Pmax Profiles	21	Qmin/Pmax (import) (Below 110kV)	-0.5 p.u.	-0.33 pu	18.2.b (ii)	C and D SPGMs	1	parameter			No comment	No Change to current Grid Code requirements - Acceptable	Not applicable to PPB		Reading the indication in the Parameter4Consultation document, the understanding is that generator is requested with power factor 0.95
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.1	Article 18.2.b.(i): SPGM: Parameters required for U-Q/Pmax Profiles	21	Qmax/Pmax (Export) (Below 110kV)	0.65 p.u.	0.33 pu	18.2.b (ii)	C and D SPGMs	1	parameter			No comment	No Change to current Grid Code requirements - Acceptable	Not applicable to PPB		Reading the indication in the Parameter4Consultation document, the understanding is that generator is requested with power factor 0.95
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.2	Article 18.2.b. (iv): SPGM: Time to Achieve Target Value within U-Q/Pmax Profile	22	Time to achieve target value	Not specified	Without undue delay but at least within 120 seconds	18.2.b (iv)	C and D SPGMs	3	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's tap will take longer than 120 second since several tap instructions will be required. What assumption was made for typical tap-changer operation time per tap?		No comment	Alligned with Ireland Grid Code and scheduling and dispatch code - Acceptable	Agree with this proposal		
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.3	Article 21.3.b (i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	23	umin (110 kV)	0.875 p.u.	0.9 p.u.	21.3.b (ii)	D PPMs	1	parameter			Agree -appears reasonable	No Change to current Grid Code requirements - Acceptable	Agree with this proposal		
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.3	Article 21.3.b (i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	23	umax (110 kV)	1.1 p.u.	1.1 p.u.	21.3.b (ii)	D PPMs	1	parameter			Agree -appears reasonable	No Change to current Grid Code requirements - Acceptable	Agree with this proposal		

Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.3	Article 21.3.b (i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	23	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.	No Change to current Grid Code requirements - Acceptable	Agree with this proposal		
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.3	Article 21.3.b (i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	23	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.	No Change to current Grid Code requirements - Acceptable	Agree with this proposal		
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.3	Article 21.3.b (i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	23	umin (275 kV)	0.875 p.u.	0.9 p.u.	21.3.b (ii)	D PPMs	1	parameter			Agree -appears reasonable	No Change to current Grid Code requirements - Acceptable	Agree with this proposal		
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.3	Article 21.3.b (i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	23	umax (275 kV)	1.1 p.u.	1.1 p.u.	21.3.b (ii)	D PPMs	1	parameter			Agree -appears reasonable	No Change to current Grid Code requirements - Acceptable	Agree with this proposal		
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.3	Article 21.3.b (i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	23	Qmin/Pmax (lead) (275 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.	No Change to current Grid Code requirements - Acceptable	Agree with this proposal		
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.3	Article 21.3.b (i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	23	Qmax/Pmax (lead) (275 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.	No Change to current Grid Code requirements - Acceptable	Agree with this proposal		
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.3	Article 21.3.b (i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	23	umin (400 kV)	0.875 p.u.	0.875 p.u.	21.3.b (ii)	D PPMs	3	parameter			Agree -appears reasonable	Alligned with Ireland Grid Code and scheduling and dispatch code - Acceptable	Not applicable to PPB		
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.3	Article 21.3.b (i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	23	umax (400 kV)	1.1 p.u.	1.05 p.u.	21.3.b (ii)	D PPMs	3	parameter			Agree -appears reasonable	Alligned with Ireland Grid Code and scheduling and dispatch code - Acceptable	Not applicable to PPB		
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.3	Article 21.3.b (i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	23	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.	No Change to current Grid Code requirements - Acceptable	Not applicable to PPB		
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.3	Article 21.3.b (i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	23	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.	No Change to current Grid Code requirements - Acceptable	Not applicable to PPB		
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.3	Article 21.3.b (i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	24	umin (Below 110kV)	0.875 p.u.	0.94 pu	21.3.b (ii)	C and D PPM	1	parameter			Agree -appears reasonable	No Change to current Grid Code requirements - Acceptable	Not applicable to PPB		
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.3	Article 21.3.b (i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	24	umax (Below 110kV)	1.1 p.u.	1.06 pu	21.3.b (ii)	C and D PPM	1	parameter			Agree -appears reasonable	No Change to current Grid Code requirements - Acceptable	Not applicable to PPB		
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.3	Article 21.3.b (i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	24	Qmin/Pmax (lead) (Below 110kV)	-0.5 p.u.	-0.33 pu	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.	No Change to current Grid Code requirements - Acceptable	Not applicable to PPB		
Voltage Theme	**Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles**	4.2.2.2.3	Article 21.3.b (i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles	24	Qmax/Pmax (lag) (Below 110kV)	0.65 p.u.	0.33 pu	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.	No Change to current Grid Code requirements - Acceptable	Not applicable to PPB		
Voltage Theme	**Reactive Power Capability below Maximum Capacity: P-Q/Pmax Profiles**	4.2.2.3.1	Article 21.3.c.(i), (ii) and (iv): PPM: Parameters required for P-Q/Pmax Profiles	25	pmin (110 - 400kV)	0.0 p.u.	0.12 p.u.	21.3.c (ii)	D PPMs	1	parameter			Agree -in line with Grid Code CC.S2.1.3.2	No Change to current Grid Code requirements - Acceptable	Agree with this proposal		
Voltage Theme	**Reactive Power Capability below Maximum Capacity: P-Q/Pmax Profiles**	4.2.2.3.1	Article 21.3.c.(i), (ii) and (iv): PPM: Parameters required for P-Q/Pmax Profiles	25	pmax (110 - 400kV)	1.0 p.u.	1.0 p.u.	21.3.c (ii)	D PPMs	1	parameter			Agree -in line with Grid Code CC.S2.1.3.2	No Change to current Grid Code requirements - Acceptable	Agree with this proposal		
Voltage Theme	**Reactive Power Capability below Maximum Capacity: P-Q/Pmax Profiles**	4.2.2.3.1	Article 21.3.c.(i), (ii) and (iv): PPM: Parameters required for P-Q/Pmax Profiles	25	Qmin/Pmax (lead) (110 - 400kV)	-0.5 p.u.	-0.33 p.u.	21.3.c (ii)	D PPMs	1	parameter			Agree -in line with Grid Code CC.S2.1.3.2	No Change to current Grid Code requirements - Acceptable	Agree with this proposal		
Voltage Theme	**Reactive Power Capability below Maximum Capacity: P-Q/Pmax Profiles**	4.2.2.3.1	Article 21.3.c.(i), (ii) and (iv): PPM: Parameters required for P-Q/Pmax Profiles	25	Qmax/Pmax (lag) (110 - 400kV)	0.65 p.u.	0.33 p.u.	21.3.c (ii)	D PPMs	1	parameter			Agree -in line with Grid Code CC.S2.1.3.2	No Change to current Grid Code requirements - Acceptable	Agree with this proposal		
Voltage Theme	**Reactive Power Capability below Maximum Capacity: P-Q/Pmax Profiles**	4.2.2.3.1	Article 21.3.c.(i), (ii) and (iv): PPM: Parameters required for P-Q/Pmax Profiles	26	pmin (Below 110kV)	0.0 p.u.	0.15 p.u.	21.3.c (ii)	C and D PPM	1	parameter			Agree with Pmin proposal. However does the P-Q capability have to rectangular for distribution connected generators?	No Change to current Grid Code requirements - Acceptable	Not applicable to PPB		
Voltage Theme	**Reactive Power Capability below Maximum Capacity: P-Q/Pmax Profiles**	4.2.2.3.1	Article 21.3.c.(i), (ii) and (iv): PPM: Parameters required for P-Q/Pmax Profiles	26	pmax (Below 110kV)	1.0 p.u.	1.0 p.u.	21.3.c (ii)	C and D PPM	1	parameter			Agree with Pmax proposal. However does the P-Q capability have to rectangular for distribution connected generators?	No Change to current Grid Code requirements - Acceptable	Not applicable to PPB		
Voltage Theme	**Reactive Power Capability below Maximum Capacity: P-Q/Pmax Profiles**	4.2.2.3.1	Article 21.3.c.(i), (ii) and (iv): PPM: Parameters required for P-Q/Pmax Profiles	26	Qmin/Pmax (lead) (Below 110kV)	-0.5 p.u.	-0.33 p.u.	21.3.c (ii)	C and D PPM	1	parameter			Does the P-Q capability have to rectangular for distribution connected generators?	No Change to current Grid Code requirements - Acceptable	Not applicable to PPB		
Voltage Theme	**Reactive Power Capability below Maximum Capacity: P-Q/Pmax Profiles**	4.2.2.3.1	Article 21.3.c.(i), (ii) and (iv): PPM: Parameters required for P-Q/Pmax Profiles	26	Qmax/Pmax (lag) (Below 110kV)	0.65 p.u.	0.33 p.u.	21.3.c (ii)	C and D PPM	1	parameter			Does the P-Q capability have to rectangular for distribution connected generators?	No Change to current Grid Code requirements - Acceptable	Not applicable to PPB		
Voltage Theme	**Reactive Power Capability below Maximum Capacity: P-Q/Pmax Profiles**	4.2.2.3.2	Article 21.3.c.(iv): PPM: Time to Achieve Target Value within P-Q/Pmax Profile	27	Time to achieve target value [transmission connected]	Not specified	Without delay but within 20 seconds	21.3.c.(iv)	C and D SPGM	3	parameter			Agree	Alligned with current SONI WFPS Setting Schedule - Acceptable	Agree with this proposal		
Voltage Theme	**Reactive Power Capability below Maximum Capacity: P-Q/Pmax Profiles**	4.2.2.3.2	Article 21.3.c.(iv): PPM: Time to Achieve Target Value within P-Q/Pmax Profile	27	Time to achieve target value [distribution connected]	Not specified	Without delay but within 20 seconds	21.3.c.(iv)	C and D SPGM	3	parameter			Agree	Alligned with current SONI WFPS Setting Schedule - Acceptable	Agree with this proposal		

Voltage Theme	**Supplementary Reactive Power Requirements**	4.2.2.4.1	Article 18.2.a: SPGM: Supplementary reactive power requirements	28	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	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.	No Change to current Grid Code requirements - Acceptable	TSO stated at the workshop there is no concern now but maybe in the future		
Voltage Theme	**Supplementary Reactive Power Requirements**	4.2.2.4.2	Article 21.3.a: PPM: Supplementary reactive power requirements	29	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.	No Change to current Grid Code requirements - Acceptable	TSO stated at the workshop there is no concern now but maybe in the future		
Voltage Theme	**Reactive Power Control Modes for PPMs**	4.2.3.1	Article 21.3.d.(iv)-Voltage Control Mode	30	t1 = time within which 90% of the change in reactive power is reached	1 – 5 sec	1	21.3.d.(iv)	C and D PGMs	1	parameter			Agree- in line with current grid code	No Change to current Grid Code requirements - Acceptable	Agree with this proposal		
Voltage Theme	**Reactive Power Control Modes for PPMs**	4.2.3.1	Article 21.3.d.(iv)-Voltage Control Mode	30	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- in line with current grid code	No Change to current Grid Code requirements - Acceptable	Agree with this proposal		
Voltage Theme	**Reactive Power Control Modes for PPMs**	4.2.3.2	Article 21.3.d (vi) - Power Factor Control Mode	31	Target power factor	Not specified	site-specific	21.3.d.(vi)	C and D PGMs	3	parameter			Agree - this is the most appropriate approach.	Alligned with current SONI WFPS Setting Schedule - Acceptable	Agree with this proposal		
Voltage Theme	**Reactive Power Control Modes for PPMs**	4.2.3.2	Article 21.3.d (vi) - Power Factor Control Mode	31	Time period to reach the set point	Not specified	5 seconds	21.3.d.(vi)	C and D PGMs	3	parameter			Agree	Alligned with current SONI WFPS Setting Schedule - Acceptable	Agree with this proposal		
Voltage Theme	**Reactive Power Control Modes for PPMs**	4.2.3.2	Article 21.3.d (vi) - Power Factor Control Mode	31	Tolerance	Not specified	5%	21.3.d.(vi)	C and D PGMs	3	parameter			Agree	Alligned with current SONI WFPS Setting Schedule - Acceptable	Agree with this proposal		
Voltage Theme	**Voltage Control System for SPGM**	4.2.4.1	Article 19.2.a and 19.2.b.(v)	32	Power Threshold	Not specified	All Type D SPGMs	19.2.b.(v)	D SPGMs	2	parameter			No comment - (requirement for PSS applicable to synchronous generation)	N/A	The TSO has stated that the requirement to fit a PPS is due to the generation profile on the System , these connections have been allowed by the TSO so this equipment should be funded by the TSO.		
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	33	Uret	0.05-0.3	0.05	14.3.a & 16.3.a	B, C, D SPGMs	3	parameter			No comment	N/A	Not applicable	FRT requirements for PGMs shall be based on a minimum grid short circuit power of 6xPmax in MVA (example: Pmax=250MW Skmin=1500MVA) This is to proposed to be included reflecting the short circuit power in the HV system to which the generating unit is connected to. As low as the short circuit power is as low is the FRT critical time	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	33	Uclear	0.7-0.9	0.7	14.3.a & 16.3.a	B, C, D SPGMs	3	parameter			No comment	N/A	Not applicable		
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	33	Urec1	Uclear	Uclear	14.3.a & 16.3.a	B, C, D SPGMs	3	parameter			No comment	N/A	Not applicable		
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	33	Urec2	0.85-0.9 & >=Uclear	0.9	14.3.a & 16.3.a	B, C, D SPGMs	3	parameter			No comment	N/A	Not applicable		
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	33	tclear	0.14-0.25	0.15	14.3.a & 16.3.a	B, C, D SPGMs	3	parameter			No comment	N/A	Not applicable		
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	33	trec1	tclear	tclear	14.3.a & 16.3.a	B, C, D SPGMs	3	parameter			No comment	N/A	Not applicable		
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	33	trec2	trec1-0.7	0.45	14.3.a & 16.3.a	B, C, D SPGMs	3	parameter			No comment	N/A	Not applicable		
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	33	trec3	trec2-1.5	trec2	14.3.a & 16.3.a	B, C, D SPGMs	3	parameter			No comment	N/A	Not applicable		
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	34	Uret	0.05-0.15	0.15	14.3.a & 16.3.a	B, C, D PPMs and Offshore PPMs	3	parameter			Agree- within RfG range	To be confirmed with WTG OEM's	Not applicable		
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	34	Uclear	Uret -0.15	0.15	14.3.a & 16.3.a	B, C, D PPMs and Offshore PPMs	3	parameter			Agree- within RfG range	To be confirmed with WTG OEM's	Not applicable		
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	34	Urec1	Uclear	Uclear	14.3.a & 16.3.a	B, C, D PPMs and Offshore PPMs	3	parameter			Agree- within RfG range	To be confirmed with WTG OEM's	Not applicable		
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	34	Urec2	0.85	0.85	14.3.a & 16.3.a	B, C, D PPMs and Offshore PPMs	3	parameter			Agree- within RfG range	To be confirmed with WTG OEM's	Not applicable		
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	34	tclear	0.14-0.25	0.25	14.3.a & 16.3.a	B, C, D PPMs and Offshore PPMs	3	parameter	250ms is deemed too long and outside international practice, we suggest 150ms		Agree- within RfG range	To be confirmed with WTG OEM's	Not applicable		
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	34	trec1	tclear	tclear	14.3.a & 16.3.a	B, C, D PPMs and Offshore PPMs	3	parameter			Agree- within RfG range	To be confirmed with WTG OEM's	Not applicable		
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	34	trec2	trec1	tclear	14.3.a & 16.3.a	B, C, D PPMs and Offshore PPMs	3	parameter			Agree- within RfG range	To be confirmed with WTG OEM's	Not applicable		
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	34	trec3	1.5-3.0	2.9	14.3.a & 16.3.a	B, C, D PPMs and Offshore PPMs	3	parameter			Agree- within RfG range	To be confirmed with WTG OEM's	Not applicable		
Voltage Theme	**Fault Ride Through Capability**	4.2.5.2	Article 16.3.a FRT Capability for PGMs connected at voltage level ³110 kV	35	Uret	0	0	16.3.a	D SPGMs	3	parameter	In the consultation document, the voltage-against-time-profile refers to phase-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	N/A	Agree with this proposal		Comments related to the FRT parameters These values (and specifically the 25%Un, 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 Scc grid power becomes comparable with the power of the generating unit, strong voltage dip leads to obscillation/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 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**	4.2.5.2	Article 16.3.a FRT Capability for PGMs connected at voltage level ³110 kV	35	Uclear	0.25	0.25	16.3.a	D SPGMs	3	parameter			Agree- within RfG range	N/A	Agree with this proposal		
Voltage Theme	**Fault Ride Through Capability**	4.2.5.2	Article 16.3.a FRT Capability for PGMs connected at voltage level ³110 kV	35	Urec1	0.5-0.7	0.5	16.3.a	D SPGMs	3	parameter			Agree- within RfG range	N/A	Agree with this proposal		
Voltage Theme	**Fault Ride Through Capability**	4.2.5.2	Article 16.3.a FRT Capability for PGMs connected at voltage level ³110 kV	35	Urec2	0.85-0.9	0.9	16.3.a	D SPGMs	3	parameter			Agree- within RfG range	N/A	Agree with this proposal		
Voltage Theme	**Fault Ride Through Capability**	4.2.5.2	Article 16.3.a FRT Capability for PGMs connected at voltage level ³110 kV	35	tclear	0.14-0.25	0.15	16.3.a	D SPGMs	3	parameter			Agree- within RfG range	N/A	Agree with this proposal		
Voltage Theme	**Fault Ride Through Capability**	4.2.5.2	Article 16.3.a FRT Capability for PGMs connected at voltage level ³110 kV	35	trec1	tclear -0.45	tclear	16.3.a	D SPGMs	3	parameter			Agree- within RfG range	N/A	Agree with this proposal		

Voltage Theme	**Fault Ride Through Capability**	4.2.5.2	Article 16.3.a FRT Capability for PGMs connected at voltage level ³110 kV	35	trec2	trec1-0.7	0.45	16.3.a	D SPGMs	3	parameter			Agree- within RfG range	N/A	Agree with this proposal		
Voltage Theme	**Fault Ride Through Capability**	4.2.5.2	Article 16.3.a FRT Capability for PGMs connected at voltage level ³110 kV	35	trec3	trec2-1.5	trec2	16.3.a	D SPGMs	3	parameter			Agree- within RfG range	N/A	Agree with this proposal		
Voltage Theme	**Fault Ride Through Capability**	4.2.5.2	Article 16.3.a FRT Capability for PGMs connected at voltage level ³110 kV	36	Uret	0	0	16.3.a	D PPMs	1	parameter			Agree- as per RfG	No Change to current Grid Code requirements - Acceptable	Agree with this proposal		
Voltage Theme	**Fault Ride Through Capability**	4.2.5.2	Article 16.3.a FRT Capability for PGMs connected at voltage level ³110 kV	36	Uclear	Uret	Uret	16.3.a	D PPMs	1	parameter			Agree- as per RfG	No Change to current Grid Code requirements - Acceptable	Agree with this proposal		
Voltage Theme	**Fault Ride Through Capability**	4.2.5.2	Article 16.3.a FRT Capability for PGMs connected at voltage level ³110 kV	36	Urec1	Uclear	Uclear	16.3.a	D PPMs	1	parameter			Agree- as per RfG	No Change to current Grid Code requirements - Acceptable	Agree with this proposal		
Voltage Theme	**Fault Ride Through Capability**	4.2.5.2	Article 16.3.a FRT Capability for PGMs connected at voltage level ³110 kV	36	Urec2	0.85	0.85	16.3.a	D PPMs	1	parameter			Agree- as per RfG	No Change to current Grid Code requirements - Acceptable	Agree with this proposal		
Voltage Theme	**Fault Ride Through Capability**	4.2.5.2	Article 16.3.a FRT Capability for PGMs connected at voltage level ³110 kV	36	tclear	0.14-0.25	0.15	16.3.a	D PPMs	1	parameter			Agree- as per RfG	No Change to current Grid Code requirements - Acceptable	Agree with this proposal		
Voltage Theme	**Fault Ride Through Capability**	4.2.5.2	Article 16.3.a FRT Capability for PGMs connected at voltage level ³110 kV	36	trec1	tclear	tclear	16.3.a	D PPMs	1	parameter			Agree- as per RfG	No Change to current Grid Code requirements - Acceptable	Agree with this proposal		
Voltage Theme	**Fault Ride Through Capability**	4.2.5.2	Article 16.3.a FRT Capability for PGMs connected at voltage level ³110 kV	36	trec2	trec1	tclear	16.3.a	D PPMs	1	parameter			Agree- as per RfG	No Change to current Grid Code requirements - Acceptable	Agree with this proposal		
Voltage Theme	**Fault Ride Through Capability**	4.2.5.2	Article 16.3.a FRT Capability for PGMs connected at voltage level ³110 kV	36	trec3	1.5-3.0	2.9	16.3.a	D PPMs	1	parameter			Agree- as per RfG	No Change to current Grid Code requirements - Acceptable	Agree with this proposal		
Voltage Theme	**Fault Ride Through Capability**	4.2.5.3.1	Article 20.2.b Fast Fault Current Injection for Symmetrical Faults	37	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	No Change to current Grid Code requirements - Acceptable	TSO has indicated that this is in line with NI Grid code connection conditions.		
Voltage Theme	**Fault Ride Through Capability**	4.2.5.3.1	Article 20.2.b Fast Fault Current Injection for Symmetrical Faults	37	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 requird. There is a need to explicity specify what "normal operating voltage range" is.	No Change to current Grid Code requirements - Acceptable	TSO has indicated that this is in line with NI Grid code connection conditions.		
Voltage Theme	**Fault Ride Through Capability**	4.2.5.3.1	Article 20.2.b Fast Fault Current Injection for Symmetrical Faults	37	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	No Change to current Grid Code requirements - Acceptable	TSO has indicated that this is in line with NI Grid code connection conditions.		
Voltage Theme	**Fault Ride Through Capability**	4.2.5.3.1	Article 20.2.b Fast Fault Current Injection for Symmetrical Faults	37	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 OEMs?	To be confirmed with WTG OEM's	TSO has indicated that this is in line with NI Grid code connection conditions.		
Voltage Theme	**Fault Ride Through Capability**	4.2.5.3.2	Article 20.2.c Fast Fault Current Injection for Asymmetrical Faults	38	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	No Change to current Grid Code requirements - Acceptable	TSO has indicated that this is in line with NI Grid code connection conditions.		
Voltage Theme	**Fault Ride Through Capability**	4.2.5.3.2	Article 20.2.c Fast Fault Current Injection for Asymmetrical Faults	38	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	No Change to current Grid Code requirements - Acceptable	TSO has indicated that this is in line with NI Grid code connection conditions.		
Voltage Theme	**Fault Ride Through Capability**	4.2.5.3.2	Article 20.2.c Fast Fault Current Injection for Asymmetrical Faults	38	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 OEMs?	To be confirmed with WTG OEM's	TSO has indicated that this is in line with NI Grid code connection conditions.		
Voltage Theme	**Fault Ride Through Capability**	4.2.5.4	Article 20.3.a Post-Fault Active Power Recovery for PPMs	39	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 and Offshore PPMs	1	parameter			Agree	No Change to current Grid Code requirements - Acceptable	TSO has indicated that this is in line with NI Grid code connection conditions.		
Voltage Theme	**Fault Ride Through Capability**	4.2.5.4	Article 20.3.a Post-Fault Active Power Recovery for PPMs	39	maximum allowed time for active power recovery	Not specified	500ms/1s	20.3.a	B, C and D PPMs and Offshore PPMs	1	parameter			Agree	No Change to current Grid Code requirements - Acceptable	TSO has indicated that this is in line with NI Grid code connection conditions.		
Voltage Theme	**Fault Ride Through Capability**	4.2.5.4	Article 20.3.a Post-Fault Active Power Recovery for PPMs	39	magnitude and accuracy for active power recovery	Not specified	90%	20.3.a	B, C and D PPMs and 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 availablable may have decreased during the disturbance for PPMs with fluctuating resource)	No Change to current Grid Code requirements - Acceptable	TSO has indicated that this is in line with NI Grid code connection conditions.		
Voltage Theme	**Fault Ride Through Capability**	4.2.5.5	Article 21.3.e Priority Given to Active or Reactive Power Contribution for PPMs	40	Prioritisation requirements during FRT	Active/Reactive	Active	21.3.e	C and D PPMs and Offshore PPMs	3	parameter			Agree - it is up to the Network Operator to choose what to prioritise	Consistent with EirGrid Grid Code - Acceptable	Agree with this proposal		
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	41	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	Agree with this proposal		
System Restoration Theme	**Operation following Tripping to House Load**	4.3.1	Article 15.5.c.(iii) Operation following tripping to house load	42	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*	3	parameter	We understand that faster synchronizing units (< 15 min) do not fall into this requirement. Units with less than 15min re-synchronization time are not required to have 4hours operation time on house load.		No comment	Alligned with SONI Power System Restoration Plan - Acceptable	As the NI Grid Code does not have this requirement it means that PGM's are exposed to future requirements albeit requires a CBA.. However the concern remains that the TSO may attempt to have this changed in the current Grid Code prior to the Network Code coming into force, and so skip the requirement for a CBA as previously happened with RoCoF leaving the existing generators with significant costs and little recompense through any other revenue stream.		
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	43	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	Timeline of 1 hour to allow operator attend PGM site will be difficult to achieve	There are many factors ~(i.e. remoteness, weather ,road & traffic conditions) that need to considered so a time isn't the only relevant parameter to measure against.	Period shall not exceed 60 minutes	The main issue here is just to get the setpoint to the generating unit. 1h can be a target value.
Protection and Instrumentation Theme	**Instrumentation : Quality of Supplies**	4.4.2	Article 15.6.b (i): Instrumentation: Quality of Supplies	44	Quality of supplies parameters to be recorded.	Not Specified	Site Specific	15(6)(b)(i)	C and D PGMs and Offshore PPMs	1	requirement			Agree - in line with practice -site specific case by case basis justified on the basis of wide variety of plant	No Change to current Grid Code requirements - Acceptable	Current practice		
Protection and Instrumentation Theme	**Dynamic System Behaviour Monitoring**	4.4.3	Article 15.6.b.(iii): Dynamic System Behaviour Monitoring	45	oscillation trigger detecting poorly damped power oscillations.	Not Specified	Site Specific	15(6)(b)(iii)	C and D PGMs and Offshore PPMs	1	parameter			Agree - in line with practice -site specific case by case basis justified on the basis of wide variety of plant	No Change to current Grid Code requirements - Acceptable	Current practice		
Protection and Instrumentation Theme	**Simulation Model Provision**	4.4.4	Article 15.6.c.(iii) Simulation Model Provision	46	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	2	requirement			Agree - additional requirement in max and min fault level data	Alligned with current Grid Code with additional inclusion of min and max short circuit levels - Acceptable	Current practice		For synchronous generator, Min/max short circuit contribution come 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	47	Earthing arrangement of the neutral-point	Not Specified	Site specific - Will be specified as a part of the connection agreement	15(6)(f)	C and D PGMs and Offshore PPMs	1	parameter			Agree - in line with practice -site specific specification	No Change to current Grid Code requirements - Acceptable	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	48	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 and Offshore PPMs	N/A	parameter			Agree	Noted	Agree with this proposal		

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	48	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 and Offshore PPMs	N/A	parameter			Agree	Noted	Agree with this proposal		
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	48	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 PGMs and Offshore PPMs	N/A	parameter			Agree	Noted	Agree with this proposal		
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	48	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 PGMs and Offshore PPMs	N/A	parameter			Agree	Noted	Agree with this proposal		
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	48	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 PGMs and Offshore PPMs	N/A	parameter			Agree	Noted	Agree with this proposal		
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	48	Instrumentation: Protocols for recorded data	Protocols for recorded data	Case by case basis	15.6.b(iv)	C, D PGMs and Offshore PPMs	N/A	parameter			Agree	Noted	Agree with this proposal		
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	48	Agreement between PGFO, the RSO and the relevant TSO		Case by case basis	15.6.b(iv)	C, D PGMs and Offshore PPMs	N/A	parameter			Agree	Noted	Agree with this proposal		
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	48	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 PGMs and Offshore PPMs	N/A	parameter			Agree	Noted	Agree with this proposal		
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	48	Synchronisation: Agreement between the RSO and the PGFO	Settings of the synchronisation devices	Case by case basis	16.4	D PGMs and Offshore PPMs	N/A	parameter			Agree	Noted	Agree with this proposal		
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	48	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	N/A	Agree with this proposal		

Note 1 SONI DS3 information