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

16 May 2018
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1. Introduction


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

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

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

(a) It is already connected to either the transmission or distribution network in Ireland by two years after entry into force of the RfG (17th May 2018); or

(b) The power-generating facility owner has concluded a final and binding contract for the purchase of the main generating plant by two years after entry into force of the RfG (17th May 2018).

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

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

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

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2. Refer to section 3.4 for more information on the definition of Maximum Capacity.
3. Refer to section 3.2 for more information on the different types and bands within RfG.
4. Refer to section 3.1 for more information on non-exhaustive parameters and non-mandatory requirements.
SONI Ltd in its role as the Transmission System Operator in Northern Ireland and by Northern Ireland Electricity Networks in its role as the Distribution System Operator in Northern Ireland is submitting an equivalent proposal document to the Utility Regulator.
1.1. Associated documents

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

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

1.2. Definitions and Interpretations

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

In this proposal document, unless the context requires otherwise:

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

1.3. Structure of this document

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

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

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

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

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

2. Scope

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

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

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

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

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3. Background

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

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

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

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

3.1. Principles underpinning the Proposals

Many of the requirements for general application exist in Ireland today in the Grid and/or Distribution Codes. Furthermore, many parameters and requirements in the Grid and Distribution Codes have been updated in recent years as a result of the work carried out under the DS3 Programme. 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 Ireland, the requirement is made mandatory nationally under the RfG.
- Where the requirement provided in the RfG is not an existing requirement in Ireland, the requirement is not made mandatory nationally under the RfG.

Non-Exhaustive Parameter Selection

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

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

http://www.eirgridgroup.com/how-the-grid-works/ds3-programme/
In the majority of cases the following assumptions are made:

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

3.2. Overview of Generator Types

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

- Type A units range from 800 W up to 0.09 MW
- Type B units range from 0.1 MW up to 4.9 MW
- Type C units range from 5 MW to 9.9 MW
- Type D units are greater than 10 MW

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

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

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

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

All generation subject to the RfG will be considered based on the actual installed capacity less house load. This represents a fundamental change to how requirements are applied to generators and should be fully understood by users.
The majority of the RfG, Articles 13-16, covers the requirements for power generating modules or PGMs.

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

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

Articles 17 – 19 cover additional requirements for synchronous PGMS or SPGMs.
Articles 20 – 22 cover additional requirements for PPMs
Articles 23 – 28 cover additional requirements for Offshore PPMs

An outline of the requirements of the RfG as applied to generators of each Type is shown below.
3.3. Overview of Topologies for Distribution Connected PGMs

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

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

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

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

<table>
<thead>
<tr>
<th>Old Name</th>
<th>New Name</th>
</tr>
</thead>
<tbody>
<tr>
<td>Type A</td>
<td>Topology 1</td>
</tr>
<tr>
<td>Type B</td>
<td>Topology 2</td>
</tr>
<tr>
<td>Type C</td>
<td>Topology 3</td>
</tr>
<tr>
<td>Type D</td>
<td>Topology 4</td>
</tr>
<tr>
<td>Type E</td>
<td>Topology 5</td>
</tr>
</tbody>
</table>

Table 1: Types Vs Topologies
4. Consultation Update

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

4.1. Summary of Submissions

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

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

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

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

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

<table>
<thead>
<tr>
<th>Section No.</th>
<th>Table No.</th>
<th>Parameter</th>
<th>Consultation Proposal</th>
<th>Final Proposal</th>
</tr>
</thead>
<tbody>
<tr>
<td>5.1.3.1</td>
<td>Table 6</td>
<td>Admissible reduction from maximum output with falling frequency</td>
<td>below 49 Hz falling by a reduction rate of 2% of the maximum capacity at 50 Hz per 1 Hz frequency drop</td>
<td>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</td>
</tr>
<tr>
<td>4.1.4.7</td>
<td>Table 17</td>
<td>Active power range</td>
<td>10%</td>
<td>SPGMs: 10% PPMs: 60% in 5 seconds and 100% in 15 seconds</td>
</tr>
<tr>
<td>5.2.2.1.1</td>
<td>Table 22</td>
<td>Maintain existing reactive power requirements in the Distribution Code.</td>
<td>Applicable for Type C and D SPGMs</td>
<td>Applicable for Type B SPGMs only</td>
</tr>
<tr>
<td>5.2.2.1.2</td>
<td>Table 23</td>
<td>Maintain existing reactive power requirements in the Distribution Code.</td>
<td>Applicable for Type C and D PPMs</td>
<td>Applicable for Type B PPMs only</td>
</tr>
<tr>
<td>5.2.2.2.1</td>
<td>Table 24</td>
<td>$U_{\text{max}}(110 \text{ kV})$</td>
<td>1.1pu</td>
<td>1.118pu</td>
</tr>
<tr>
<td>5.2.2.2.1</td>
<td>Table 24</td>
<td>$U_{\text{max}}(220 \text{ kV})$</td>
<td>1.1pu</td>
<td>1.118pu</td>
</tr>
<tr>
<td>5.2.2.2.1</td>
<td>Table 24</td>
<td>$U_{\text{min}}(400 \text{ kV})$</td>
<td>0.875pu</td>
<td>0.9pu</td>
</tr>
<tr>
<td>5.2.2.2.1</td>
<td>Table 25</td>
<td>$U_{\text{max}}(10 \text{ kV} &amp; 20 \text{ kV})$</td>
<td>1.1pu</td>
<td>1.118pu</td>
</tr>
<tr>
<td>5.2.2.2.1</td>
<td>Table 25</td>
<td>$U_{\text{max}}(38 \text{ kV})$</td>
<td>1.1pu</td>
<td>1.118pu</td>
</tr>
<tr>
<td>5.2.2.2.3</td>
<td>Table 27</td>
<td>$U_{\text{max}}(110 \text{ kV})$</td>
<td>1.1pu</td>
<td>1.118pu</td>
</tr>
<tr>
<td>5.2.2.2.3</td>
<td>Table 27</td>
<td>$U_{\text{max}}(220 \text{ kV})$</td>
<td>1.1pu</td>
<td>1.118pu</td>
</tr>
<tr>
<td>5.2.2.2.3</td>
<td>Table 27</td>
<td>$U_{\text{min}}(400 \text{ kV})$</td>
<td>0.875pu</td>
<td>0.9pu</td>
</tr>
<tr>
<td>5.2.2.2.3</td>
<td>Table 28</td>
<td>$U_{\text{max}}(10 \text{ kV} &amp; 20 \text{ kV})$</td>
<td>1.1pu</td>
<td>1.118pu</td>
</tr>
<tr>
<td>Section</td>
<td>Table</td>
<td>Description</td>
<td>1.1pu</td>
<td>1.118pu</td>
</tr>
<tr>
<td>-------------</td>
<td>---------</td>
<td>------------------------</td>
<td>--------</td>
<td>---------</td>
</tr>
<tr>
<td>5.2.2.3</td>
<td>28</td>
<td>(U_{\text{max}}(38 \text{ kV}))</td>
<td>1.1pu</td>
<td>1.118pu</td>
</tr>
<tr>
<td>5.2.2.3</td>
<td>29</td>
<td>(U_{\text{max}}(10 \text{ kV} &amp; 20 \text{ kV}))</td>
<td>1.1pu</td>
<td>1.118pu</td>
</tr>
<tr>
<td>5.2.2.3</td>
<td>29</td>
<td>(U_{\text{max}}(38 \text{ kV}))</td>
<td>1.1pu</td>
<td>1.118pu</td>
</tr>
<tr>
<td>5.2.2.5.1</td>
<td>37</td>
<td>Requirement only applies to PPMs</td>
<td>C and D PGMs</td>
<td>C and D PPMs</td>
</tr>
<tr>
<td>5.2.2.5.2</td>
<td>38</td>
<td>Requirement only applies to PPMs</td>
<td>C and D PGMs</td>
<td>C and D PPMs</td>
</tr>
</tbody>
</table>
4.3. Derogation Requests and Proposed Changes

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

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

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

**Frequency Sensitive Mode, Active Power Range**

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

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

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

*Proposed Solution*

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

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

**Frequency Sensitive Mode, PPM Frequency Response Capability**

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

The TSO expressed our concerns in the Consultation Document in relation to a potential loss of frequency response from PPM units due to the limitations set out in RfG. The current requirements in the Grid Code require a 60% increase in Active Power within 5 seconds and 100% of expected increase (droop response) within 15 seconds of a frequency event. This requirement is core to the achievement of a 40% RES-E target and the ability to operate the system at System Non Synchronous Penetration (SNSP) levels up to 75%. The RfG range in Article 15.2.d only allows us specify a value for the change in power output relative to the Active Power output at the moment the frequency threshold was reached (or the maximum capacity as defined by the TSO) between 1.5-10% i.e. it does not allow us to specify the levels that currently exist in the Grid Code. However to lose the capability provided for in today’s Grid Code would be very damaging to the success of the DS3 program and ultimately to the integration of high levels of renewable energy into the power system. We do not believe that the regulations intentionally undermine this capability.
Following discussions with ENTSO-E they have informed us that there is an understanding that the requirements under RfG are not intended to reduce the capability of the fleet of generation connected to a power system. The understanding is that once a National Code was submitted to the National Regulatory Authority by 2012 that the requirements of that code can be considered when implementing the RfG nationally.

**Proposed Solution**

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

**Voltage Withstand Capability and Associated Reactive Power Maximum Voltage**

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

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

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

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

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

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

**Proposed Solutions**

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

2. This does not apply to generators connected at Distribution voltages below 110kV (10kV, 20kV and 38kV). However, even if it did, it of itself will not be sufficient to deal with a historical misalignment that has developed between the nominal voltages and the voltages to which the distribution system is currently planned and operated. Such is the quantum of this divergence, Connection Point voltages well in excess of 1.1pu of nominal are routinely encountered.
3. The requirement for the SOs to mandate the required reactive power behaviour would force ESBN to alter its Planning Standards going forward, which would have the potential to unacceptably restrict the quantum of generation that could be connected at a reasonable cost and/or introduce substantial increases in costs.

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

I. Add a new column of Declared Supply Voltages to Table 1A, as mandated by EN50160, with values chosen such that the maximum and minimum voltages per Planning Standards, will be within +/- 1.1 pu of these values

II. Add a clarifying statement to the effect that all references to voltage in Connection Network Codes relate to the Declared Supply Voltages.

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

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

4.1 Frequency
4.2 Voltage including Fault Ride Through
4.3 System Restoration
4.4 Protection and Instrumentation

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

The tables contain:

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

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

Justification Codes

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

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

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

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

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

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

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

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

Non-Exhaustive Parameter Selection

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

Requirement

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

Proposal

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

Table 2 Frequency Withstand Time Periods

Justification

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

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

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

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

Consultation Submissions

Submission 1

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

SO Comments

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

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

Submission 2

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

SO Comments

As RfG Network Code doesn’t not specify requirements for frequencies of 47.0 - 47.5 Hz and 51.5 - 52.0 Hz, TSOs may specify requirements for these frequency ranges, if required, for the secure operation of their Transmission System.
While we acknowledge that the frequency requirements within the ranges of 47.0 - 47.5 Hz and 51.5 - 52.0 Hz are in addition to the requirements stated in the RfG, they are existing requirements in the Grid Code and are essential for the security of the Transmission System.

The Irish transmission is quite small with very little interconnection. As such it is far more likely to be susceptible to these extremes of frequency than the larger European transmission grids.

The removal or reduction of these frequency requirements would reduce the overall ability of the Transmission System to withstand a severe frequency event. As such, we are proposing the retention of these requirements for all PGMs.

Submission 3

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

SO Comments

Comment noted, however, the TSO has selected the minimum time in the range allowed under the RfG.
5.1.2 Rate of Change of Frequency

5.1.2.1 Article 13.1 (b): RoCoF

Non-Exhaustive Parameter Selection

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

Requirement

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

Proposal: RoCoF Withstand Capability

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

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

Justification: RoCoF Withstand Capability

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

Consultation Submissions:

Submission 1

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

SO Comments

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

Submission 2

One respondent asked whether a guarantee of compliance will be enough to prove compliance. It is stated that many asynchronous generators can meet in excess of the requirement but are unaware of how to prove compliance.
SO Comments
For Transmission Connected generators a guarantee from the generator will not suffice as evidence of compliance.
At the moment, compliance is verified by the following:
- review of settings
- provision of the necessary studies
- Grid Code Compliance Testing via frequency step injection
The proposal is to maintain these compliance requirements.

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

Submission 3
One respondent commented that they would be concerned about the ability of Loss of Mains projection to detect true loss of mains events for SPGMs operating in trickle import scenarios if a setting of 1Hz/sec over 500ms was selected. They commented that RoCoF protection relays set at 1Hz/sec over 500ms can fail to detect loss of mains events during dynamic testing, which would be similar in nature to localised loss of mains events. And while this RoCoF setting of 1Hz/sec over 500ms is being specified for Types C & D PGM's in the RfG Network Code's it is also being applied to a more numerous quantity of Type B's in this jurisdiction. We would ask what consideration is being given to this situation.

SO Comments
The concerns are noted however, for the topologies and circumstances referred to, the DSO are not changing the RoCoF setting, for the very reasons mentioned in the justification section above.
Proposal: Loss of Mains Protection [Transmission Connected]

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

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

Justification: Loss of Mains Protection [Transmission Connected]

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

Consultation Submissions:

Submission 1

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

SO Comments

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

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

Submission 2

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

SO Comments

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

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

Submission 4

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

**SO Comments**

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

We expect the relevant transmission connected PGMs to manage their own processes, whilst respecting these requirements.
**Proposal: Loss of Mains Protection [Distribution Connected]**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Parameter in RfG</th>
<th>Proposal</th>
<th>Positive and Negative RoCoF</th>
<th>Article Number</th>
<th>Type Applicability</th>
<th>Justification Code</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Generator Category</td>
<td>Pick Up</td>
<td>Time Delay</td>
<td></td>
</tr>
<tr>
<td>The proposal for loss of mains protection [Distribution Connected]</td>
<td>Not Specified</td>
<td>DFIG / Full Converter Generator</td>
<td>2 Hz/s</td>
<td>0.3s</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Synchronous Generator / Directly Connected Induction Generator</td>
<td>H &gt; 3 MWs /MVA</td>
<td>0.6 Hz/s</td>
<td>0.6s</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Synchronous Generator / Directly Connected Induction Generator</td>
<td>H ≤ 3 MWs /MVA</td>
<td>1.0 Hz/s</td>
<td>0.6s</td>
<td></td>
</tr>
</tbody>
</table>

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

**Justification: RoCoF Protection settings [Distribution connected]**

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

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

---

10 "Conditions Governing Connection to the Distribution System:

* Connections at MV and 38 kV
* Embedded Generators at LV, MV and 38 kV"
Consultation Submissions:

**Submission 1**

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

**SO comments**

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

**Submission 2**

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

**SO Comments**

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

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

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

Non-Exhaustive Parameter Selection

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

Requirement

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

![Figure 1 Maximum Power Capability Reduction with Falling Frequency](image)

Proposal

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Parameter in RfG</th>
<th>Proposal</th>
<th>Article Number</th>
<th>Type Applicability</th>
<th>Justification Code</th>
</tr>
</thead>
<tbody>
<tr>
<td>Admissible active power reduction from maximum output with falling frequency</td>
<td>below 49 Hz falling by a reduction rate of 2% of the maximum capacity at 50 Hz per 1 Hz frequency drop <strong>or</strong> Below 49.5 Hz falling by a reduction rate of 10% of the maximum capacity at 50 Hz per 1 Hz frequency drop</td>
<td>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</td>
<td>13.4 (a)</td>
<td>A, B, C and D PGMs and Offshore PPMs</td>
<td>3</td>
</tr>
</tbody>
</table>

Table 6 Admissible active power reduction from maximum output with falling frequency
**Justification: Transient Response**

For the transient domain:

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

**Justification: Static Response**

For the steady state domain:

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

**Consultation Submissions:**

**Submission 1**

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

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

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

**SO Comments**

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

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

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

Submission 2

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

SO Comments

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

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

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

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

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

Submission 3

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

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

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

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

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

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

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

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

Submission 4

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

SO Comments

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

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

Table 7 Admissible active power reduction from maximum output

Justification

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

Consultation Submissions

Submission 1

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

SO Comments

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

Submission 2

One respondent commented that Art 13.5 is used for GT unit to complement art 13.4, by providing ambient condition and taking into consideration the technical capabilities of the correspondent technology. They comment that this Article was created to accommodate gas turbine technologies; however the way it was defined is poorly reaching the goal, since every GT performs differently. It is suggested that a possible approach is to leave the characteristic you defined as reference for all and to request GT manufacturer to provide expected power deviation function of ambient temperature. This would fulfill also the 13.5. They noted that; the requirements are only critical at full power for GT characteristic and that the requirement cannot be tested and it doesn't drive competition. Any compensative system are risky and someway useless as a collateral effect they can lead to flame out and when employed, they are slow acting logic, not in line with supporting the initial RoCoF. Compensative system brings the risk of flame-out, and as well cannot be tested, which they consider not to be a good trade for the requirements. A respondent suggested again reviewing EUTurbines response on this topic.

SO Comments

As per the ENTSO-E IGD “Maximum Admissible active power reduction at low frequencies” dated 31/01/2018, the PGM should provide the characteristic expected over a full temperature range (eg-10oC - 40oC). The performance specified under Article 13.5 is at 10oC.
5.1.3.3 Article 13.6: Remote operation of facility to cease active power output

Non-Mandatory Requirement being made Mandatory

Applies to Type A and B PGMs

Requirement

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

Proposal

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

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

Justification

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

The intention of the phrase, ‘in due time for plant design’ is intended to mean during the connection offer phase.
5.1.3.4  Article 13.7: Automatic connection to the network

Non-Exhaustive Parameter Selection

Applies to Type A, B and C PGMs

Requirement

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

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

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

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

Proposal

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

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

Justification: Frequency Ranges and Time Delay [Distribution Connected]

The values exist today for distribution connected generators, as stipulated in Conditions Governing\(^{11}\). The proposed frequency range and time delay are per the existing requirements in the Distribution Code.

Justification: Maximum admissible gradient of increase in power

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

\(^{11}\) “Conditions Governing Connection to the Distribution System: • Connections at MV and 38 kV Embedded Generators at LV, MV and 38 kV”
Post Consultation Note

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

Consultation Submissions: Frequency Ranges and Time Delay

Submission 1

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

SO Comments

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

Submission 2

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

SO Comments

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

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

Consultation Submissions: Maximum admissible gradient of increase in power

Submission 1

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

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

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

Submission 2

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

SO Comments

This was a typo. 10% was intended.

Submission 3

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

SO Comments

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

The System Services out of scope
5.1.3.5 Article 14.2.b: Remote operation of power output

Non-Mandatory Requirement being made Mandatory

Applies to Type B PGMs

Requirement

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

(a) to control active power output, the power-generating module shall be equipped with an interface (input port) in order to be able to reduce active power output following an instruction at the input port; and

(b) the relevant system operator shall have the right to specify the requirements for further equipment to allow active power output to be remotely operated.

Proposal

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

Table 10 Remote operation of Power Output

Justification

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

Consultation Submissions:

Submission 1

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

SO Comments

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

Submission 2
One respondent commented that the specification of the equipment by the SO should a collaborative process with industry and should be proposed through the forum of the DCRP and require the consent of all members to approve.

SO Comments

The Respondent is correct in stating that the DCRP and its workings may well be involved in a high level decision to invoke this requirement for a given class or cohort of generators. However, there is a level of detail beyond which the Distribution Code is not the appropriate vehicle to disseminate information, some of which may be site specific.
5.1.3.6  **Article 15.2.a: Achieving Active Power Set points**

Non-Exhaustive Parameter Selection

Applies to Types C and D PGMs

Requirements

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

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

The relevant system operator or the relevant TSO shall establish the period within which the adjusted active power set point must be reached. The relevant TSO shall specify a tolerance (subject to the availability of the prime mover resource) applying to the new set point and the time within which it must be reached;

Proposal

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Proposal</th>
<th>Article Number</th>
<th>Type Applicability</th>
<th>Justification Code</th>
</tr>
</thead>
<tbody>
<tr>
<td>The period within which the adjusted active power setpoint must be reached</td>
<td>10 seconds response time plus the ramp rate for the unit. NB where wind turbines have to be turned on to achieve the set point then a maximum of 3 minutes response time is allowed.</td>
<td>15.2 (a)</td>
<td>C and D PGMs</td>
<td>1</td>
</tr>
<tr>
<td>Tolerance (subject to the availability of the prime mover resource) applying to the new setpoint and the time within which it must be reached</td>
<td>For PGMs, the maximum of 1 MW or 1% of dispatch quantity is applied. For PPMs, the maximum of +/- 3% of registered capacity or +/- 0.5 MW.</td>
<td>15.2 (a)</td>
<td>C and D PGMs</td>
<td>3</td>
</tr>
</tbody>
</table>

Table 11: Achieving Active Power Set-points
Justification

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

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

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

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

Submission 1
One respondent commented that it is slightly unclear. Is the intention to allow WFPS 3 minutes to begin generating then follow the required ramp rate?

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

Submission 2
One respondent requested clarification in relation to how this 3 minute requirement fits with the above Article 13.7 requiring minimum 5mins?

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

Submission 3
One respondent commented that they agree in principle with the proposals. They requested a clarification stating "10 seconds response time plus time to reach set point corresponding to the ramp rate for the unit." They did comment that this may be problematic for wind turbines that need time to yaw into the wind after a period of extended shutdown.

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

Submission 4

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

SO Comments

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

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

Submission 1

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

SO Comments

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

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

Submission 2

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

SO Comments

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

While we are not currently aware of PGM type to which these requirements cannot be applied, we are conscience that PGM technology is constantly evolving, and as such these requirements and the ability to apply these requirements to different PGM types are reviewed on an ongoing basis. This review includes discussion with the relevant OEMs, etc., as required.
Submission 3

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

SO Comments

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

Submission 4

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

SO Comments

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

5.1.4.1 Frequency Modes Explanation

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

Frequency Sensitive Mode:

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

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

- In normal operation the parameters to be specified are the % droop and any associated frequency dead bands. There is no parameter relating to the time allowed to achieve the required response. These parameters are consistent with today’s Grid Code requirements for normal governor regulation.

- The parameters to be specified to assist with recovering the system frequency following a sudden imbalance and associated frequency step change are a specified % increase in active power relative to the maximum generation of the unit (or available active power for PPMs) within a specified time period (usually seconds). This is similar to today’s Grid Code requirements for units to provide operating reserves.

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

Limited Frequency Sensitive Mode:

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

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

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

Summary

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

<table>
<thead>
<tr>
<th>RfG Frequency Control Mode</th>
<th>Equivalent Grid Code Frequency Control Mode for PPMs</th>
<th>Equivalent Grid Code Frequency Control Mode for SPGM</th>
</tr>
</thead>
<tbody>
<tr>
<td>LFSM-O</td>
<td>PPM in wind following mode &amp; curve 1</td>
<td>Not applicable in Ireland today</td>
</tr>
<tr>
<td>LFSM-U</td>
<td>Not applicable in Ireland today</td>
<td>Not applicable in Ireland today</td>
</tr>
<tr>
<td>FSM Normal</td>
<td>PPM in active power set point control mode &amp; curve 1 or curve 2</td>
<td>Normal governor regulation</td>
</tr>
<tr>
<td></td>
<td>PPM in wind following mode &amp; curve 2</td>
<td></td>
</tr>
<tr>
<td>FSM Frequency Step Change</td>
<td>As above</td>
<td>Operating Reserves</td>
</tr>
</tbody>
</table>

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

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

Table 12: LFSM-O Parameter Selection

Justification:

Frequency Threshold

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

Droop Settings

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

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

**Submission 1**

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

**SO Comments**

This will be considered during the Grid Code modification process.
5.1.4.3 Article 13.2.b: LFSM-O: Automatic disconnection and reconnection

Non-Mandatory Requirement being made Mandatory

Applies to Type A PGM

Requirement

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

Proposal

<table>
<thead>
<tr>
<th>Requirement</th>
<th>Requirement in RfG</th>
<th>Proposal</th>
<th>Article Number</th>
<th>Type Applicability</th>
<th>Justification Code</th>
</tr>
</thead>
<tbody>
<tr>
<td>Automatic disconnection and reconnection of PGMs</td>
<td>Allow or do not allow</td>
<td>Do not allow</td>
<td>13.2 (b)</td>
<td>A PGMs</td>
<td>1</td>
</tr>
</tbody>
</table>

Table 13: LFSM-O Automatic Disconnection & Reconnection

Justification

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

Consultation Submissions:

Submission 1

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

SO Comments

This will be considered during the Grid Code modification process.
5.1.4.4 Article 13.2.f: LFSM-O: Actions at minimum regulating level

Non-Mandatory Requirement being made Mandatory

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

Requirement

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

(i) continuing operation at this level; or

(ii) further decreasing active power output;

Proposal

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

Table 14: LFSM-O Actions at Minimum Regulating Level

Justification

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

Consultation Submissions:

Submission 1

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

SO Comments

This will be considered during the Grid Code modification process.
5.1.4.5 Article 15.2.c: LFSM-U Parameter Selection

Non-Exhaustive Parameter Selection

Applies to Type C and D PGMs and offshore PPMs

Requirement

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

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

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

Proposal

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

Table 15 LFSM-U Frequency Threshold & Droop Settings

Justification

Frequency Threshold:

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

Droop Settings:

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

Submission 1

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

SO Comments

This will be considered during the Grid Code modification process.
5.1.4.6 Article 15.2.d. (i) and (ii): FSM Parameter Selection

Non-Exhaustive Parameter Selection

Applies to Types C and D PGMs and Offshore PPMs

Requirement

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

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

Proposal

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

Table 16 FSM Parameter Selection
Justification: Active Power Range

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

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

Post Consultation Note

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

Justification: Frequency Response Insensitivity & Frequency Response deadband

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

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

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

*In addition to the individual requirements for Frequency Response Insensitivity (ΔF) and Frequency Response deadband and as per Annex V of the System Operating Guidelines12 (SOGL), the maximum combined effect of Frequency Response Insensitivity and Frequency Response deadband cannot exceed a value of +/- 15 mHz

Consultation Submissions

Submission 1

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

SO Comments

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

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

**Submission 1**

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

**SO Comments**

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

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

Table 17 Activating full active power frequency response
Justification: Active Power Range

SPGMs

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

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

PPMs

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

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

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

Post Consultation Note

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

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

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

**Justification: Maximum admissible choice of full activation time**

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

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

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

**Consultation Submissions: Active Power Range**

*Submission 1*

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

*SO Comments*

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

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

*Submission 2*
One respondent commented that in the case of a CCGT, the 100% refers to the combined total maximum of the CCGT’s capacity (GTs and STs), allowing for any specific configuration limitations. They noted that the harmonisation of the EirGrid and SONI Grid Codes is not planned as part this proposal document. The primary concern of this proposal document is to ensure that the requirements of the RfG is met

SO Comments

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

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

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

Submission 3

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

SO Comments

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

Submission 4

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

SO Comments

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

Submission 5
One respondent requested further clarification on how the frequency response in the Network Codes aligns with the current Grid Codes requirements.

SO Comments

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

Submission 6

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

SO Comments

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

Submission 7

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

SO Comments

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

a. Ramp up rate – the maximum rate of increase in a Generation Unit Output after the end of the start-up period.

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

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

Submission 1

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

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

**Submission 2**

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

**SO Comments**

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

**Submission 3**

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

**SO Comments**

Noted.

**Consultation Submissions: Maximum admissible choice of full activation time**

**Submission 1**

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

**SO Comments**

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

**Submission 2**

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

**SO Comments**

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

Submission 3

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

SO Comments

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

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

If a PGM experiences a time delay of 2 seconds (\( t_1 \)) within the time to full output activation (\( t_2 \) of 5 seconds), the PGM will only have 3 seconds to reach their full output activation and while it may be difficult, it should still be achievable. The obligation is on the PGM to minimize the anytime delay, thus maximizing the time available to reach their full output.

Submission 4

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

SO Comments

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

Submission 5

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

Noted

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

**Submission 1**

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

**SO Comments**

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

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

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

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

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

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

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

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

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

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

Non-Exhaustive Parameter Selection

Applies to Type C PGMs

Requirement

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

Proposal

<table>
<thead>
<tr>
<th>Parameter in RfG</th>
<th>Proposal</th>
<th>Article Number</th>
<th>Type Applicability</th>
<th>Justification Code</th>
</tr>
</thead>
<tbody>
<tr>
<td>Minimum Voltage below which Module will automatic disconnect</td>
<td>Voltage</td>
<td>Duration</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Not specified</td>
<td>0.87 p.u.</td>
<td>3s</td>
<td>15.3</td>
<td>C (PPM)</td>
</tr>
<tr>
<td>Not specified</td>
<td>0.8 p.u.</td>
<td>1.1s</td>
<td>15.3</td>
<td>C (PPM)</td>
</tr>
<tr>
<td>Not specified</td>
<td>0.87 p.u.</td>
<td>2.5s</td>
<td>15.3</td>
<td>C (SPGM)</td>
</tr>
<tr>
<td>Not specified</td>
<td>0.8 p.u.</td>
<td>0.7s</td>
<td>15.3</td>
<td>C (SPGM)</td>
</tr>
<tr>
<td>Maximum Voltage above which Module will automatic disconnect</td>
<td>Not specified</td>
<td>1.12 p.u.</td>
<td>0.7s</td>
<td>15.3</td>
</tr>
</tbody>
</table>

Table 19: Parameters for Automatic Disconnection

Justification

The values are specified as stipulated in the Conditions Governing Connection to the Distribution System\(^1\).
5.2.1.2 Article 16.2.c: Type D Automatic Disconnection Due to Voltage Level

Non-Exhaustive Parameter Selection

Applies to Type D PGMs

Requirement

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

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

Table 20 specifies the voltage and duration settings.

<table>
<thead>
<tr>
<th>Parameter in RfG</th>
<th>Proposal</th>
<th>Article Number</th>
<th>Type Applicability</th>
<th>Justification Code</th>
</tr>
</thead>
<tbody>
<tr>
<td>Minimum Voltage below which Module will automatic disconnect</td>
<td>Not specified</td>
<td>Not Allowed</td>
<td>16.2.c</td>
<td>D PGMs</td>
</tr>
<tr>
<td>Maximum Voltage above which Module will automatic disconnect</td>
<td>Not specified</td>
<td>Not Allowed</td>
<td>16.2.c</td>
<td>D PGMs</td>
</tr>
</tbody>
</table>

Table 20: Type D Parameters for Automatic Disconnection

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

The current Grid Code does not stipulate voltage thresholds which allow for automatic disconnection. The TSO invokes the right to prohibit automatic disconnection from the Transmission System.
Consultation Submissions: Minimum Voltage below / Maximum Voltage above which Module will automatic disconnect

**Submission 1**

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

**SO Comments**

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

**Submission 2**

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

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

**SO Comments**

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

The SO notes this comment that RfG art 6.3 gives generators the right to ask for industry specific requirements. This will be considered during the Grid and Distribution Code modification process.
Proposal: Automatic Disconnection Due to Voltage Level [Distribution Connected]

Table 21 specifies the voltage and duration settings.

<table>
<thead>
<tr>
<th>Parameter in RfG</th>
<th>Proposal</th>
<th>Article Number</th>
<th>Type Applicability</th>
<th>Justification Code</th>
</tr>
</thead>
<tbody>
<tr>
<td>Minimum Voltage below which Module will automatic disconnect</td>
<td>Not specified</td>
<td>0.87 p.u.</td>
<td>3s</td>
<td>15.3</td>
</tr>
<tr>
<td></td>
<td>Not specified</td>
<td>0.8 p.u.</td>
<td>1.1s</td>
<td>15.3</td>
</tr>
<tr>
<td></td>
<td>Not specified</td>
<td>0.87 p.u.</td>
<td>2.5s</td>
<td>15.3</td>
</tr>
<tr>
<td></td>
<td>Not specified</td>
<td>0.8 p.u.</td>
<td>0.7s</td>
<td>15.3</td>
</tr>
<tr>
<td>Maximum Voltage above which Module will automatic disconnect</td>
<td>Not specified</td>
<td>1.12 p.u.</td>
<td>0.7s</td>
<td>15.3</td>
</tr>
</tbody>
</table>

Table 21: Parameters for Automatic Disconnection

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

The values are specified as stipulated in the Conditions Governing Connection to the Distribution System\textsuperscript{10}.

Consultation Submissions

Submission 1

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

SO Comments

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

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

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

1. Connection at 110 kV or more,
2. Connection at less than 110 kV,
3. Different topology connections at less than 110 kV.
5.2.2.1 Reactive Power Capability for Type B PGMs

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

Non-Mandatory Requirement being made Mandatory

Applies to Type B PGMs

Requirement

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

Proposal

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

Table 22: Right to specify reactive power capability for SPGMs

Justification

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

Consultation Submissions

Submission 1

DCC 10.10.2.1

<table>
<thead>
<tr>
<th>Voltage Range</th>
<th>Connected at:</th>
<th>At 100% Registered Capacity</th>
<th>At 33% of Registered Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>99kV ≤ V ≤ 123kV</td>
<td>110kV</td>
<td>0.93 power factor leading to 0.85 power factor lagging</td>
<td>0.7 power factor leading to 0.4 power factor lagging</td>
</tr>
<tr>
<td>85kV ≤ V ≤ 99kV</td>
<td>Unity power factor to 0.85 power factor lagging</td>
<td>0.7 power factor leading to 0.4 power factory lagging</td>
<td></td>
</tr>
</tbody>
</table>

SO Comments

The requirements depicted in this table relate to 110 kV connected generators.
5.2.2.1.2 Article 20.2.a: Reactive Power capability for Type B PPMs

Non-Mandatory Requirement being made Mandatory

Applies to Type B PPMs

Requirement

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

Proposal

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

Table 23: Right to specify reactive power capability for PPMs

Justification

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

Consultation Submissions

Submission 1

DCC 10.10.2.1

<table>
<thead>
<tr>
<th>Voltage Range</th>
<th>Connected at</th>
<th>At 100% registered Capacity</th>
<th>At 3% of Registered Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>33kV ≤ V ≤ 110kV</td>
<td>110V</td>
<td>0.90 power factor leading to 0.85 power factor lagging</td>
<td>0.7 power factor leading to 0.4 power factor lagging</td>
</tr>
<tr>
<td>85kV ≤ V ≤ 99kV</td>
<td></td>
<td>0.7 power factor leading to 0.85 power factor lagging</td>
<td>0.7 power factor leading to 0.4 power factor lagging</td>
</tr>
</tbody>
</table>

SO Comments

The requirements depicted in this table relate to 110 kV connected generators.
5.2.2.2 Reactive Power Capability at Maximum Capacity: U-Q/Pmax Profiles

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

Non-Exhaustive Parameter Selection

Applies to Type C and D SPGMs

Requirement

In relation to voltage stability, synchronous power-generating modules shall fulfil the requirements with regard to reactive power capability at maximum capacity. For that purpose a U-Q/Pmax-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 ($P_{\text{max}}$).

The figure above represents boundaries of a U-Q/Pmax-profile by the voltage at the connection point, expressed by the ratio of its actual value and the reference 1p.u. value, against the ratio of the reactive power ($Q$) and the maximum capacity ($P_{\text{max}}$). The position, size and shape of the envelope are indicative. The dimensions of the inner envelope are limited by a maximum range of $Q/P_{\text{max}}$ of 1.08p.u. and maximum range of steady state voltage level of 0.218p.u.
Proposal for SPGMs connected at a voltage level ≥ 110 kV

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

<table>
<thead>
<tr>
<th>Connection Voltage</th>
<th>Parameter</th>
<th>Parameter in RfG</th>
<th>Proposal (Inner Envelope)</th>
<th>Article Number</th>
<th>Type Applicability</th>
<th>Justification Code</th>
</tr>
</thead>
<tbody>
<tr>
<td>110 kV</td>
<td>u_min</td>
<td>0.875 p.u.</td>
<td>0.9 p.u.</td>
<td></td>
<td></td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>u_max</td>
<td>1.118 p.u.</td>
<td>1.118 p.u.</td>
<td></td>
<td></td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Q_min/P_max (lead)</td>
<td>-0.5 p.u.</td>
<td>-0.5 p.u.</td>
<td></td>
<td></td>
<td>2</td>
</tr>
<tr>
<td></td>
<td>Q_max/P_max (lag)</td>
<td>0.65 p.u.</td>
<td>0.52 p.u.</td>
<td></td>
<td></td>
<td>2</td>
</tr>
<tr>
<td>220 kV</td>
<td>u_min</td>
<td>0.875 p.u.</td>
<td>0.9 p.u.</td>
<td></td>
<td></td>
<td>2</td>
</tr>
<tr>
<td></td>
<td>u_max</td>
<td>1.118 p.u.</td>
<td>1.118 p.u.</td>
<td></td>
<td></td>
<td>2</td>
</tr>
<tr>
<td></td>
<td>Q_min/P_max (lead)</td>
<td>-0.5 p.u.</td>
<td>-0.5 p.u.</td>
<td></td>
<td></td>
<td>2</td>
</tr>
<tr>
<td></td>
<td>Q_max/P_max (lag)</td>
<td>0.65 p.u.</td>
<td>0.52 p.u.</td>
<td></td>
<td></td>
<td>2</td>
</tr>
<tr>
<td>400 kV</td>
<td>u_min</td>
<td>0.875 p.u.</td>
<td>0.9 p.u.</td>
<td>18.2.b (ii)</td>
<td>D SPGMs</td>
<td></td>
</tr>
<tr>
<td></td>
<td>u_max</td>
<td>1.05 p.u.</td>
<td>1.05 p.u.</td>
<td></td>
<td></td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Q_min/P_max (lead)</td>
<td>-0.5 p.u.</td>
<td>-0.5 p.u.</td>
<td></td>
<td></td>
<td>2</td>
</tr>
<tr>
<td></td>
<td>Q_max/P_max (lag)</td>
<td>0.65 p.u.</td>
<td>0.52 p.u.</td>
<td></td>
<td></td>
<td>2</td>
</tr>
</tbody>
</table>

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

Justification: SPGMs connected at a voltage level ≥ 110 kV

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

The proposed reactive power capability parameters (Q_min/P_max (lead) and Q_max/P_max (lag)) of inner envelope has to take into account the supplementary reactive power which is compensated by the equipment connecting the alternator terminal and connection point in order to maintain the currently required reactive power capability. The voltage (u_min and u_max) ranges are aligned with the RfG voltage ranges within which the PGM shall stay connected to the network and operate normally.
Post Consultation Note

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

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

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

Consultation Submissions

Submission 1

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

SO Comments

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

RfG does apply to the following generators:

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

Submission 2

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

SO Comments

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

Submission 3
One respondent commented that in their opinion. The under excited (leading) proposal of -0.5 (Qmin/Pmax) and 0.9p.u. voltage and overexcited (lagging) proposal of 0.52 (Qmax/Pmax) and 1.1p.u. voltage can have a huge impact in the generator size, min and max voltage at generator terminal and GSUT size (and price). They would also like to note that a generator may be unlikely to operate at a leading power factor when there is a low voltage at the connection point or similarly at a lagging power factor when there is a high voltage. They suggest that the shape of the inner envelope should take this into account and be translated to a more appropriate shape like a parallelogram.

SO Comments

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

Submission 4

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

SO Comments

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

Submission 5

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

SO Comments

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

Submission 6

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

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

**Submission 7**

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

**SO Comments**

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

**Submission 8**

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

**SO Comments**

The harmonisation of the two existing Grid Code would be 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 fulfill the rectangular inner envelope shape.

Submission 10

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

SO Comments

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

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

The reactive power capability is required at the connection point and could be provided by a combination of generator and supportive reactive compensation in order to fulfill the rectangular inner envelope shape.
Proposal for SPGMs connected at a voltage level < 110 kV

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

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

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

Justification: SPGMs connected at a voltage level <110 kV

Voltage

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

<table>
<thead>
<tr>
<th>Description</th>
<th>Nominal Voltage</th>
<th>Normal Operating Range [kV]²</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Lower bound</td>
</tr>
<tr>
<td>MV</td>
<td>10kV</td>
<td>9.6</td>
</tr>
<tr>
<td>MV</td>
<td>20kV</td>
<td>19.3</td>
</tr>
<tr>
<td>HV</td>
<td>38kV</td>
<td>35.6</td>
</tr>
<tr>
<td>110kV</td>
<td>110kV</td>
<td>99</td>
</tr>
</tbody>
</table>

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

It is proposed that for connections at voltages <110 kV, the power factor requirements stated for non-wind generators, will have to be maintained for the voltages in Table 6A (as per the Distribution Code table numbering) above.
**Q limits:**
It is proposed to align the Q limits for the U-Q profile with the P-Q profile. The synchronous power-generating module shall be capable of moving to any operating point within its U-Q/P\(_{\text{max}}\) profile in appropriate timescales to target.

**Post Consultation Note**

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

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

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

**Consultation Submissions**

**Submission 1**

One respondent commented that the value of 0 p.u. Q\(_{\text{max}}\)/P\(_{\text{max}}\) (export) seems to be wrong. They mention that the Northern Ireland proposed value is 0.33 p.u.

**SO Comments**

This is correct for Ireland, only PPMs >5MW and what will be referred to as Topology 2 post RfG adoption are permitted to export reactive power.
5.2.2.2.2 Article 18.2.b. (iv): SPGM: Time to Achieve Target Value within U-Q/Pmax Profile

Non-Exhaustive Parameter Selection

Applies to Type C and D SPGMs

Requirement

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

Proposal

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Proposal</th>
<th>Article Number</th>
<th>Type Applicability</th>
<th>Justification Code</th>
</tr>
</thead>
<tbody>
<tr>
<td>Time to achieve target value [transmission connected]</td>
<td>Without undue delay but at least within 120 seconds</td>
<td>18.2.b (iv)</td>
<td>C and D SPGMs</td>
<td>1</td>
</tr>
<tr>
<td>Time to achieve target value [distribution connected]</td>
<td>Without undue delay but at least within 120 seconds</td>
<td>18.2.b (iv)</td>
<td>C and D SPGMs</td>
<td>3</td>
</tr>
</tbody>
</table>

Table 26: Timescales to Achieve Target Values at Maximum Capacity

Justification: Transmission Connected

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

Justification: Distribution Connected

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

Submission 1

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

SO Comments

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

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

Consultation Submissions: Distribution Connected

Submission 1

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

SO Comments

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

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

For other distribution connected SPGMs. There is no intent at this time for ESBN to dispatch reactive power.
5.2.2.2.3 Article 21.3.b (i) and (ii) & Article 25.5: PPM: Parameters required for U-Q/Pmax Profiles

Non-Exhaustive Parameter Selection

Applies to Type C and D PPMs and Offshore PPMs

Requirement

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

![Figure 3: U-Q/Pmax-profile for Power Park Modules](image)

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

The dimensions of the inner envelope are limited by a maximum range of Q/P_{max} of 0.66 and maximum range of steady state voltage level of 0.218 p.u.
Proposal for PPMs connection at a voltage level \( \geq 110 \text{ kV} \)

Table 27 lists the parameters which describe the U-Q/P\(_{\text{max}}\)-profile for PPMs connected at a voltage level \( \geq 110 \text{ kV} \).

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

Table 27: Definition of a U-Q/P\(_{\text{max}}\)-profile at Maximum Capacity PPMs: connected \( \geq 110 \text{ kV} \) or more

**Justification: PPMs connected at a voltage level \( \geq 110 \text{ kV} \):**

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

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

**Post Consultation Note**

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

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

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

Consultation Submissions

Submission 1

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

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

SO Comments

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

This is applicable for all generators connected @ voltage level ≥110 kV
Proposal for PPMs connected at a voltage level < 110 kV

Table 28 lists the parameters which describe the U-Q/P\textsubscript{max}-profile for PPMs connected at a voltage level < 110 kV and in Topology 2\textsuperscript{13}.

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

\textsuperscript{13} See section 3.3 for a detailed description of the topologies.
Table 29 lists the parameters which describe the U-Q/Pmax-profile for PPMs connected a voltage level < 110 kV and in all other Topologies.

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

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

Justification: PPMs connected at a voltage level <110 kV

Voltage

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

<table>
<thead>
<tr>
<th>Description</th>
<th>Nominal Voltage</th>
<th>Normal Operating Range [kV]$^1$</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Lower bound</td>
</tr>
<tr>
<td>MV</td>
<td>10kV</td>
<td>9.6</td>
</tr>
<tr>
<td>MV</td>
<td>20kV</td>
<td>19.3</td>
</tr>
<tr>
<td>HV</td>
<td>38kV</td>
<td>35.6</td>
</tr>
<tr>
<td>110kV</td>
<td></td>
<td>99</td>
</tr>
</tbody>
</table>

Linkage between Reactive Power requirements and voltage ranges:

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

$^{14}$ See section 3.3 for a detailed description of the topologies.
DCC 11.4.5, which covers existing Types [Topologies] A and B [>5 MW], does explicitly state that the P-Q capability must be maintained across the voltage ranges is Table 6A.

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

Figure 4 below depicts the DCC 11.4.5 requirement graphically.

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

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

Post Consultation Note

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

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

Submission 1

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

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

SO Comments

For DSO connected generators please see shapes in the justification section above.
5.2.2.3 Reactive Power Capability below Maximum Capacity: P-Q/Pmax Profiles

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

Non-Exhaustive Parameter Selection

Applies to Type C and D PPMs

Requirement

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

The figure below represents boundaries of a P- Q/Pmax-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 (Pmax). The position, size and shape of the inner envelope are indicative.

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

Figure 5: P-Q/Pmax-profile of a PPM
Proposal PPMs connected at a voltage level ≥ 110 kV

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

<table>
<thead>
<tr>
<th>Connection Voltage</th>
<th>Parameter in RfG</th>
<th>Proposal</th>
<th>Article Number</th>
<th>Type Applicability</th>
<th>Justification Code</th>
</tr>
</thead>
<tbody>
<tr>
<td>110 to 400 kV</td>
<td>P\textsubscript{min}</td>
<td>0.0 p.u.</td>
<td>0.12 p.u.</td>
<td>21.3.c (ii)</td>
<td>D PPMs</td>
</tr>
<tr>
<td></td>
<td>P\textsubscript{max}</td>
<td>1.0 p.u.</td>
<td>1.0 p.u.</td>
<td>21.3.c (ii)</td>
<td>D PPMs</td>
</tr>
<tr>
<td></td>
<td>Q\textsubscript{min}/P\textsubscript{max} (lead)</td>
<td>-0.5 p.u.</td>
<td>-0.33 p.u.</td>
<td>21.3.c (ii)</td>
<td>D PPMs</td>
</tr>
<tr>
<td></td>
<td>Q\textsubscript{max}/P\textsubscript{max} (lag)</td>
<td>0.65 p.u.</td>
<td>0.33 p.u.</td>
<td>21.3.c (ii)</td>
<td>D PPMs</td>
</tr>
</tbody>
</table>

Table 30: Timescales to Achieve Target Values at Maximum Capacity

Justification: PPMs connected at a voltage level ≥ 110 kV

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

Consultation Submissions

Submission 1

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

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

SO Comments

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

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

Reactive power capability for generators connected to the distribution system could vary (see Figure 6).
Proposal PPMs connected at a voltage level < 110 kV

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

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

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

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

Table 31: P-Q/P_{max}-profile below Maximum Capacity PPMs: connection @ <110 kV & in Topology 2
Table 32 lists the parameters which describe the P-Q/P\textsubscript{max}-profile for PPMs connected at a voltage level <110 kV and in Topologies 3 and 4.

<table>
<thead>
<tr>
<th>Connection Voltage</th>
<th>Parameter</th>
<th>Parameter in RfG</th>
<th>Proposal</th>
<th>Article Number</th>
<th>Type Applicability</th>
<th>Justification Code</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(p_{\text{min}})</td>
<td>0.0 p.u.</td>
<td>0.12 p.u.</td>
<td>21.3.c (ii)</td>
<td>C and D PPM</td>
<td>1</td>
</tr>
<tr>
<td>10 kV, 20 kV or 38 kV.</td>
<td>(p_{\text{max}})</td>
<td>1.0 p.u.</td>
<td>1.0 p.u.</td>
<td>21.3.c (ii)</td>
<td>C and D PPM</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>(q_{\text{min}}/p_{\text{max}}) (lead)</td>
<td>-0.5 p.u.</td>
<td>Power factor range from 0.92 [-0.42 Q / P\text{max}] to unity [0 Q/P\text{max}]</td>
<td>21.3.c (ii)</td>
<td>C and D PPM</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>(q_{\text{max}}/p_{\text{max}}) (lag)</td>
<td>0.65 p.u.</td>
<td>Power factor range from 0.92 [-0.42 Q / P\text{max}] to unity [0 Q/P\text{max}]</td>
<td>21.3.c (ii)</td>
<td>C and D PPM</td>
<td>1</td>
</tr>
</tbody>
</table>

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

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

<table>
<thead>
<tr>
<th>Connection Voltage</th>
<th>Parameter</th>
<th>Parameter in RfG</th>
<th>Proposal</th>
<th>Article Number</th>
<th>Type Applicability</th>
<th>Justification Code</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(p_{\text{min}})</td>
<td>0.0 p.u.</td>
<td>0.12 p.u.</td>
<td>21.3.c (ii)</td>
<td>C and D PPM</td>
<td>1</td>
</tr>
<tr>
<td>10 kV, 20 kV or 38 kV.</td>
<td>(p_{\text{max}})</td>
<td>1.0 p.u.</td>
<td>1.0 p.u.</td>
<td>21.3.c (ii)</td>
<td>C and D PPM</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>(q_{\text{min}}/p_{\text{max}}) (lead)</td>
<td>-0.5 p.u.</td>
<td>Power factor range from 0.92 [-0.42 Q / P\text{max}] to 0.95 [-0.33 Q/P\text{max}]</td>
<td>21.3.c (ii)</td>
<td>C and D PPM</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>(q_{\text{max}}/p_{\text{max}}) (lag)</td>
<td>0.65 p.u.</td>
<td>Power factor range from 0.92 [-0.42 Q / P\text{max}] to 0.95 [-0.33 Q/P\text{max}]</td>
<td>21.3.c (ii)</td>
<td>C and D PPM</td>
<td>1</td>
</tr>
</tbody>
</table>

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

Justification: PPMs connected at a voltage level <110 kV

Proposal is as per current Distribution Code requirements.

Consultation Submissions

Submission 1

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

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

SO Comments

For DSO connected generators please see shapes in the justification section above.
5.2.2.3.2 Article 21.3.c. (iv): PPM: Time to Achieve Target Value within P-Q/Pmax Profile

Non-Exhaustive Parameter Selection

Applies to Type C and D PPMs

Requirement

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

Proposal

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

Table 34: Timescales to Achieve Target Values at Maximum Capacity

Justification

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

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

Non-Mandatory Requirement being made Mandatory

Applies to Type C and D SPGMs

Requirement

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

Proposal

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

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

Justification

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

Consultation Submissions

Submission 1

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

SO Comments

Any supplementary reactive power compensation required to offset the reactive power demand of the line or cable between the connection point and generator site will be identified during the connection offer process as per WFPS 1.6.3.2 of the Grid Code. The DSO does not currently have any such instances.
5.2.2.4.2 Article 21.3.a: PPM: Supplementary reactive power requirements

Non-Mandatory Requirement being made Mandatory

Applies to Type C and D PPMs

Requirement

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

Proposal

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

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

Justification

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

Consultation Submissions

Submission 1

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

SO Comments

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

The DSO does not currently have any such instances.
5.2.2.5 Reactive Power Control Modes for PPMs

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

Non-Exhaustive Parameter Selection

Applies to Type C and D PPMs

Requirement

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

Proposal

The proposed times are listed in Table 37.

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

Table 37: Parameters for Voltage Control Mode

Justification

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

The time $t_2$ to achieve 100% of the change in reactive power is set to 5 seconds. This is a new requirement that is not currently set in the Grid Code.
5.2.2.5.2 Article 21.3.d (vi) - Power Factor Control Mode

Non-Exhaustive Parameter Selection

Applies to Type C and D PPMs

Requirement

For the purpose of power factor control mode, the power park module shall be capable of controlling the power factor at the connection point within the required reactive power range with a target power factor in steps no greater than 0.01.

Proposal

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

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

Table 38: Parameters for Power Factor Control Mode

Justification

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

Consultation Submissions

Submission 1

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

SO Comments

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

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

Non-Exhaustive Parameter Selection

Applies to Type D SPGMs

Requirement

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

Proposal

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Parameter in RfG</th>
<th>Proposal</th>
<th>Article Number</th>
<th>Type Applicability</th>
<th>Justification Code</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power Threshold</td>
<td>Not specified</td>
<td>All Type D PGMs</td>
<td>19.2.b.(v)</td>
<td>D SPGMs</td>
<td>2</td>
</tr>
</tbody>
</table>

Table 39: Power Threshold above which PSS Function is required

Justification

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

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

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

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

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

Non-Exhaustive Parameter Selection

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

Requirement

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

![Fault Ride Through Profile of a Power-Generating Module](image)

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

That lower limit is specified for synchronous power-generating modules and power park modules connected below the 110 kV level in the following subsections.
Proposal: SPGMs connected at a voltage level < 110 kV

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

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

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

Justification: SPGMs connected at a voltage level <110 kV

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

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

**Submission 1**

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

**SO Comments**

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

**Submission 2**

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

**SO Comments**

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

**Submission 3**

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

SO Comments

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

Submission 4

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

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

SO Comments

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

Submission 5

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

SO Comments

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

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

Just for clarity, the right with is the RSO to agree this. ESBN is happy to enter into discussions with any customer in this regard.
Proposal: PPMs connected at a voltage level < 110 kV

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

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

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

Justification: PPMs connected at a voltage level <110 kV

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

![Figure 8: FRT capability PPM connected @ <110 kV](image-url)
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.

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

That lower limit is specified for synchronous power-generating modules and power park modules connected at or above 110 kV in the following subsections.
Proposal: SPGMs connected at a voltage level ≥ 110 kV

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

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

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

Justification: SPGMs connected at a voltage level ≥110 kV

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

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

Submission 1

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

SO Comments

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

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

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

Submission 2

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

SO Comments

Noted.

Submission 3

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

SO Comments

The SO notes this comment that RfG art 6.3 gives generators the right to ask for industry specific requirements. This will be considered during the Grid and Distribution Code modification process.
Proposal: PPMs connected at a voltage level ≥ 110 kV

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

<table>
<thead>
<tr>
<th>No. on</th>
<th>Parameter</th>
<th>Parameter in RfG</th>
<th>Proposal</th>
<th>Article Number</th>
<th>Type Applicability</th>
<th>Justification Code</th>
</tr>
</thead>
<tbody>
<tr>
<td>Graph</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>$U_{\text{ret}}$</td>
<td>0 p.u.</td>
<td>0</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>$U_{\text{ret}}$</td>
<td>0 p.u.</td>
<td>0</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$t_{\text{clear}}$</td>
<td>140 – 250 ms</td>
<td>150 ms</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>$U_{\text{clear}}$</td>
<td>$U_{\text{ret}}$</td>
<td>$U_{\text{ret}}$</td>
<td>16.3.a (i)</td>
<td>D PPMs</td>
<td>2</td>
</tr>
<tr>
<td></td>
<td>$t_{\text{clear}}$</td>
<td>$t_{\text{clear}}$</td>
<td>$t_{\text{clear}}$</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>$U_{\text{rec1}}$</td>
<td>$U_{\text{clear}}$</td>
<td>$U_{\text{clear}}$</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$t_{\text{rec1}}$</td>
<td>$t_{\text{clear}}$</td>
<td>$t_{\text{clear}}$</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>$U_{\text{rec1}}$</td>
<td>$U_{\text{clear}}$</td>
<td>$U_{\text{clear}}$</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$t_{\text{rec2}}$</td>
<td>$t_{\text{rec1}}$</td>
<td>$t_{\text{rec1}}$</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>$U_{\text{rec2}}$</td>
<td>0.85 p.u.</td>
<td>0.85 p.u.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$t_{\text{rec3}}$</td>
<td>1.5 – 3.0 s</td>
<td>2.9 s</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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

Justification: PPMs connected at a voltage level ≥110 kV

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

![FRT capability of PPMs connected at ≤ 110 kV](image)

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

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

Submission 1

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

SO Comments

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

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

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

Submission 2

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

SO Comments

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

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

Non-Exhaustive Parameter Selection

Applies to Type B, C and D PPM

Requirement

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

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

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

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

Table 44: Fast Fault Current Injection - Symmetrical Faults

**Justification:**

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

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

**Consultation Submissions: End of Voltage Deviation**

**Submission 1**

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

**SO Comments**

Normal operating range is specified from 0.9 p.u. to 1.118 p.u. as per RfG (see Article 16 2 (a) (i)). This is a mandatory and exhaustive parameter which does not form a part of this proposal document.
Consultation Submissions: the timing and accuracy of the fast fault current, which may include several stages during a fault and after its clearance

Submission 1

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

SO Comments

This requirement is as per today’s Grid Code requirements (WFPS1.4.2 c).
5.2.4.3.2 Article 20.2.c Fast Fault Current Injection for Asymmetrical Faults

Non-Exhaustive Parameter Selection

Applies to Type B, C and D PPM

Requirement

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

Proposal

<table>
<thead>
<tr>
<th>Parameter in RfG</th>
<th>Proposal</th>
<th>Article Number</th>
<th>Type Applicability</th>
<th>Justification Code</th>
</tr>
</thead>
<tbody>
<tr>
<td>Voltage threshold for fast fault current injection</td>
<td>During voltage dips i.e. when the voltage is below 0.9 p.u.</td>
<td>20.2.b</td>
<td>B, C and D PPMs</td>
<td>1</td>
</tr>
<tr>
<td>the characteristics of the fast fault current, including the time domain for measuring the voltage deviation and fast fault current</td>
<td>Reactive current should be provided for the duration of the voltage deviation within the rating of the PPM</td>
<td>20.2.b</td>
<td>B, C and D PPMs</td>
<td>1</td>
</tr>
<tr>
<td>the timing and accuracy of the fast fault current, which may include several stages during a fault and after its clearance</td>
<td>Rise Time no greater than 100ms and a Settling Time no greater than 300ms.</td>
<td>20.2.b</td>
<td>B, C and D PPMs</td>
<td>2</td>
</tr>
</tbody>
</table>

Table 45: Fast Fault Current Injection - Asymmetrical Faults

Justification:

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

According to WFPS1.4.2 of the Grid Code and DCC11.2.2 of the Distribution Code, the provision of reactive current shall continue until the Transmission System voltage recovers to within the normal operational range as specified in CC8.3.1, or for at least 500 ms, whichever is sooner. The reactive current response shall be supplied within the rating of PPM, with a Rise Time no greater than 100ms and a Settling Time no greater than 300ms.
Consultation Submissions: the timing and accuracy of the fast fault current, which may include several stages during a fault and after its clearance

**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) and applies for symmetrical and asymmetrical faults. The requirements are as follows:

The reactive current response shall be supplied within the rating of the Controllable WFPS, with a Rise Time no greater than 100ms and a Settling Time no greater than 300ms.
**5.2.4.4 Article 20.3.a Post-Fault Active Power Recovery for PPMs**

**Non-Exhaustive Parameter Selection**

**Applies to Type B, C and D PPM**

**Requirement**

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

**Proposal**

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

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Parameter in RfG</th>
<th>Proposal</th>
<th>Article Number</th>
<th>Type Applicability</th>
<th>Justification Code</th>
</tr>
</thead>
<tbody>
<tr>
<td>when the post-fault active power recovery begins, based on a voltage criterion</td>
<td>Not specified</td>
<td>$u_n &lt; 0.9 \text{ p.u.}$</td>
<td>20.3.a</td>
<td>B, C and D PPMs</td>
<td>1</td>
</tr>
<tr>
<td>maximum allowed time for active power recovery</td>
<td>Not specified</td>
<td>500ms/1s</td>
<td>20.3.a</td>
<td>B, C and D PPMs</td>
<td>1</td>
</tr>
<tr>
<td>magnitude and accuracy for active power recovery</td>
<td>Not specified</td>
<td>90%</td>
<td>20.3.a</td>
<td>B, C and D PPMs</td>
<td>1</td>
</tr>
</tbody>
</table>

**Table 46: Post-Fault Active Power Recovery for PPMs**

**Justification**

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

**Consultation Submissions**

**Submission 1**

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

**SO Comments**

The SOs note this comment and this will be considered during the Grid and Distribution Code modification process.
5.2.4.5 Article 21.3.e Priority Given to Active or Reactive Power Contribution for PPMs

Non-Exhaustive Parameter Selection

Applies to Type C and D PPMs

Requirement

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

Proposal

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

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Parameter in RfG</th>
<th>Proposal</th>
<th>Article Number</th>
<th>Type Applicability</th>
<th>Justification Code</th>
</tr>
</thead>
<tbody>
<tr>
<td>Prioritisation requirements during FRT</td>
<td>Active/Reactive</td>
<td>Active</td>
<td>21.3.e</td>
<td>C and D PPMs</td>
<td>1</td>
</tr>
</tbody>
</table>

Table 47: Priority given to Active or Reactive Power Contribution

Justification

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

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

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

Table 48: List of Non-Mandatory and not invoked Requirements for Generators
5.3 System Restoration Theme

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

- Operation of PGM following tripping to house load.

5.3.1 Operation following tripping to house load

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

Non-Exhaustive Parameter Selection

Applies to Types C and D PGMs and offshore PPMs

Requirement

A power-generating module with a minimum re-synchronisation time greater than 15 minutes after its disconnection from any external power supply must be designed to trip to house load from any operating point in its P-Q-capability diagram. In this case, the identification of house load operation must not be based solely on the system operator’s switchgear position signals. Power-generating modules shall be capable of continuing operation following tripping to house load, irrespective of any auxiliary connection to the external network. The minimum operation time shall be specified by the relevant system operator in coordination with the relevant TSO, taking into consideration the specific characteristics of prime mover technology.

Proposal

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

Table 49: Operation Following Tripping to House Load

Justification

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

Consultation Submissions

Submission 1

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

SO Comments

Yes, your understanding is correct.

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

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

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

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

5.5.1.1 Article 15.2.b: Manual, local measures

Non-Exhaustive Parameter Selection

Applies to Types B, C and D PGMs

Requirement

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

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

Proposal

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

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

Justification:

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

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

Consultation Submissions

Submission 1

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

SO Comments

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

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

Non-Mandatory Requirement being made Mandatory

Applies to Types C and D PGMs and offshore PPMs

Requirement

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

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

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

Proposal

<table>
<thead>
<tr>
<th>Requirement</th>
<th>Requirement in RfG</th>
<th>Proposal</th>
<th>Article Number</th>
<th>Type Applicability</th>
<th>Justification Code</th>
</tr>
</thead>
<tbody>
<tr>
<td>Quality of supplies parameters to be recorded.</td>
<td>Not Specified</td>
<td>Site Specific</td>
<td>15(6)(b)(i)</td>
<td>C and D PGMs and offshore PPMs</td>
<td>3</td>
</tr>
</tbody>
</table>

Table 51: Quality of Supplies Parameters to be Recorded

Justification:

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

- Varying station and/or generation unit configurations and generation types.
- Compatibility with existing equipment
5.5.3 Dynamic System Behaviour Monitoring

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

Non-Exhaustive Parameter Selection

Applies to Types C and D PGMs and offshore PPMs

Requirement

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

Proposal

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Proposal</th>
<th>Article Number</th>
<th>Type Applicability</th>
<th>Justification Code</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oscillation trigger detecting poorly damped power oscillations.</td>
<td>Site Specific</td>
<td>15(6)(b)(iii)</td>
<td>C and D PGMs and offshore PPMs</td>
<td>3</td>
</tr>
</tbody>
</table>

Table 52: Oscillation Trigger Detecting Poorly Damped Power Oscillations

Justification

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

- Varying station and/or generation unit configurations and generation types.
- Compatibility with existing equipment
5.5.4 Simulation Model Provision

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

Non-Mandatory Requirement being made Mandatory

Applies to Types C and D PGMs and offshore PPMs

Requirement

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

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

Proposal

<table>
<thead>
<tr>
<th>Requirement</th>
<th>Requirement in RfG</th>
<th>Proposal</th>
<th>Article Number</th>
<th>Type Applicability</th>
<th>Justification Code</th>
</tr>
</thead>
<tbody>
<tr>
<td>Model Provision</td>
<td>Not Specified</td>
<td>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</td>
<td>15(6)(c)(iii)</td>
<td>C and D PGMs and offshore PPMs</td>
<td>3</td>
</tr>
</tbody>
</table>

Table 53: Simulation Model Provision

Justification

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

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

Consultation Submissions

Submission 1

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

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

Submission 2

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

SO Comments

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

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

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

Submission 3

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

SO Comments

That is correct but not measured in MVA. The inclusion of the additional two fields in the PCA will address this and will only require the conversion of the short circuit levels, as are currently provided, into MVA.
5.5.5 Neutral-point at the network side of step transformers

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

Non-Exhaustive Parameter Selection

Applies to Types C and D PGMs and offshore PPMs

Requirement

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

Proposal

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

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

Justification:

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

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

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

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

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

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

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

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

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

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

By email to gridcode@eirgrid.com

Our Ref: EN01-005648

9 February 2018

Dear Sir,

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

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

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

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

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

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

This consultation response is not confidential.

We welcome the opportunity to provide comments to the EirGrid and ESB Networks’ proposal dated 20th December 2017 (and updated with clarifications on 17th January 2018) for the general application of technical requirements in accordance with Articles 13-28 of the Commission Regulation (EU) 2016/631 establishing the network code on requirements for grid connection of generators. Please find attached document entitled “RES Ltd Response Republic of Ireland RfG Parameter Consultation” which contains our detailed comments.
The above-referred comments are offered in a spirit of positive cooperation and we will be happy to clarify any of the points raised in our consultation response.

Yours faithfully

Claver Chitambo  
Senior Electrical Engineer, Ireland  
E Claver.Chitambo@res-group.com  
T +44 1788 220 789
9th February 2018

Consultation Response to EirGrid and ESB Networks

Dear Sir/Madam,

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

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

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

- ISEA is very concerned that the adoption of the RfGs will lead to an increased technical and cost burden on micro and small generation projects. Increased costs will undermine the economics of a sector that is struggling to establish itself and could leave many small generation projects unviable.
- The 2015 Energy White Paper specifically calls for the engagement of citizens in our energy transition and it is essential that this overarching policy is not undermined or frustrated by technical standards.
• It is important that the RfGs are adapted in a sensible way that is appropriate for the Irish Electricity System. It is not good practice to introduce rules which shall require derogations for swathes of generators to be commercially viable.
• Increasing technical and cost requirements disadvantages new market entrants from those who have benefitted from established market practice. New entrants are penalised by being held to a higher technical threshold than existing projects with which they are competing. This undermines market principles and acts as a barrier to new entrants.
• ISEA is concerned that the application of the 1.1 pu limit (Umax) for 38kV and MV connections (Section 4.2.2.2. Reactive Power Capability at Maximum Capacity) could significantly disadvantage solar PV generators seeking connections to the Distribution System. Whilst the majority of solar PV generators will not result in long shallow connections, the application of such limits will most likely lead to 38kV line upgrades for embedded generators. Given the total cost of such upgrades are borne by the generator which triggers the upgrade, this would lead to an intolerable situation whereby solar PV projects will which would otherwise be delivered will become unviable. This cannot be permitted to occur.

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

Yours sincerely,

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

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

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

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

Detailed Response

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

The examples provided at the ESB Networks/EirGrid workshop highlight the potential impact of the network code changes. Under the existing ESB Network connection planning standards a 33MW generator can connect with up to 27km of 38kV cable before the voltage rise limit is exceeded. This would reduce to only 4km with the 1.1pu voltage limits proposed in the network codes. It appears there will likely be similar reductions for MV connections.
The practical impact of the proposed new voltage limits is that new generators connecting under the ECP-1 process could have more expensive grid connections. As most windfarm connections require dedicated shallow connections more than 5-10km, the change will likely impact on a high percentage of distribution applicants. Impacts could include requiring the generator to connect at a higher voltage, the requirements for larger conductors, greater levels of network reinforcement or the projects having to reduce the MEC to achieve a viable connection method. As the new RES support scheme will be auction based, these increased connection costs will result directly in higher costs for the Irish consumer.

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

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

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

As Table 6a from the distribution code below shows, for the nominal voltage of 38kV, an operational voltage range of 35.6kV to 43.8kV is allowed. This is -6% and +15% from the nominal voltage. The sample 38kV connection diagram below also shows that ESB Networks usually have a voltage range of 40.8kV to 42.3kV at 38kV busbars, which is substantially higher than the nominal 38kV voltage. As mentioned above, the use of the wide voltage range, particularly at the upper end, is to allow for connection of demand on long distribution connections. It should be noted that 42.3kV, the higher end of the busbar voltage, is already above the 1.1pu. There appears to be similar issues for the medium voltages of 10kV and 20kV.
The IWEA strongly oppose the implementation of the new 1.1pu voltage limit at 38kV and MV. The IWEA request that at 38kV the current limit of 1.15pu or 43.8kV is maintained and at MV the 1.125pu or 22.5kV is maintained. IWEA believes that there may be some technical solutions of how to address the impact of the change to voltage limits in the network codes. For example, changing the nominal voltage from 38kV to 40kV. However, considering the potential interactions of a technical solution to the overall operation and design of the distribution system we believe that ESB Networks are best placed to review and advise on technical solutions.

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

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

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

Non-confidential

Response prepared by MullanGrid Consulting for IWFA

by email to: gridcode@eirgrid.com
1. **Introduction**

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

2. **Comments on Section 4.2.2.2. Reactive Power Capability at Maximum Capacity: U-Q/PMax Profiles & Section 4.2.2.1 Article 18.2.b(i); SPGM: Parameters required for U-Q/Pax Profiles**

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

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

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

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

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

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

As Table 6a below shows for the nominal voltage of 38kV, a voltage range of 35.6kV to 43.8kV is allowed for generator connections. This is -6% and +15% from the nominal voltage. The sample 38kV connection diagram below also shows that ESB Networks usually have a voltage range of 40.8kV to 42.3kV at 38kV busbars, which is substantially higher than the nominal 38kV voltage. As mentioned above, the use of the wide voltage range, particularly at the upper end, is to allow for connection of demand on long distribution connections. It should be noted that 42.3kV, the higher end of the busbar voltage, is already above the 1.1pu. There appears to be similar issues for the medium voltages of 10kV and 20kV.
The IWFA strongly oppose the implementation of the new 1.1 pu voltage limit at 38kV and MV. The IWFA request that at 38kV the current limit of 1.15pu or 43.8kV is maintained and at MV the 1.125pu or 22.5kV is maintained. IWFA believes that there may be some technical solutions to address the impact of the change to voltage limits in the network codes. For example, changing the nominal voltage from 38kV to 40kV. However, considering the potential interactions of a technical solution with the overall operation and design of the distribution system we believe that ESB Networks are best placed to review and advise on technical solutions.

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

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

1. in the short term, derogations should be requested from these sections of the network codes, and,
2. in the medium term, an enduring solution should be devised and implemented.
RfG Art 13 (4) and (5): power vs frequency: Manufacturers’ recommendations
Art 13:

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

... 

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

a) clearly specify the ambient conditions applicable;
b) take account of the technical capabilities of power-generating modules

No requirement to dynamic behaviour. The requirement can be interpreted as steady-state.

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

- Gas Turbines output is influenced by different external factors. Depending on ambient conditions, power drop exceeds allowed values in Art 13 figure 2.

- Principle steady-state behaviour is shown in att. figure (values are only indicative!)

- Dynamic behaviour is worse since compensating power control loops need time to react to frequency drop (if reserve is available)

**Technical and ambiental limitations to be considered in requirement!**
Recommendations for IGD and national implementation

- Apply lower end of RfG range in Art 13 fig 2 for steady-state
- Allow further relaxation according to Art. 13 (5) (a) in case of evident technical constraints (without derogation process); consideration of known behaviour of plants at maximum output is better for system stability than increased risk of trip!
- Allow further relaxation in case short-term dynamic requirement (timeframe tbd) is deemed to be necessary and allowed by RfG
- Apply ISO 2314 reference temperature (15°C) as the relevant ambient condition to both steady-state and dynamic requirement (if applicable): standard condition for turbine design and average temperature in many countries in the EU
- Behaviour at other conditions can be provided by manufacturers on a project specific basis for consideration in system studies
A significant shift in environmental policies and energy deregulation in the last decade has led to the growth of renewable energy sources. Led by the development of wind farms throughout Europe, changes to ‘Grid Codes’ have been implemented requiring embedded generation schemes to stay connected during the presence of system faults (Fault Ride Through requirements). This is contrary to the traditional approach, whereby the power plants were not required to stay connected. Changes to the grid codes also include wider operating limits under steady state conditions (Voltage, power factor limits etc). These changes impose significant stresses on the genset and associated components such as the alternator. Genset manufacturers are posed with the problem of not just dealing with these new challenging operating conditions, but also variation in the grid code requirements across various network operators and countries.

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

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

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

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

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

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

A. Genset Going into a Fault and Riding Through

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

B. Fault Clearing and Grid Coming Back Online

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

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

A. Pre-fault Ride Through

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

\[ P_e = \frac{E}{q T} X \sin \delta + \frac{V_T}{2} \frac{X^2 - X q}{X d} \sin 2\delta \]

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

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

B. Fault Ride Through

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

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

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

A. Design for compliance
B. Design for robustness

A. Design for Compliance

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

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

(b) Fault ride through requirements state that the genset must not pole slip up to the maximum fault clearing time stated by the grid codes – 150 ms for Germany. Pole slip is caused by excessive acceleration and a high steady state load angle of the alternator; pole slip can therefore be avoided by designing an alternator with a low \( X_d \) to ensure a low enough steady state load angle, a high inertia constant (rotor inertia / machine kVA) to reduce acceleration during transients and the sub-transient reactances \( (X''d, X''q) \) and hence sub-transient saliency to tune the electrical time constants.
These changes involve significant modifications to the electrical machine design; for example, an optimal tuning of the reactance involves either a derate or designing the machine with a bigger air gap. Any change to the machine design (like air gap increase) will affect the overall performance of the machine (say efficiency) and so care needs to be taken to ensure overall performance does not take a hit. There is also a limit on how much inertia can be added to any alternator.

B. Design for Robustness

To operate a genset in a grid code compliant application means to expose the alternator to huge forces and stresses – both thermomechanically and electrically. The various causes of stresses in the alternator are:

(a) Thermal stresses on the stator windings – caused by over-current conditions (reduced voltage under steady-state operation): danger to the lifetime of the insulation – alternator needs to be de-rated

(b) Mechanical stresses – the huge current transients induce large electromagnetic forces on the stator windings which cause displacement / vibration of the windings.

Figure 5 captures the 3 components of the electromagnetic force in an electrical machine and what causes them - Current transients are a function of the sub-transient and transient reactances of the alternator and hence by may be modified to reduce the fault currents and hence winding forces to acceptable levels.

Additionally, mechanical reinforcement of the windings can be ensured by designing a suitable bracing and picking the right impregnation for the windings to minimise vibrations / winding displacement.

(c) Thermal stresses on the damper bars – due to the huge currents induced during long fault ride through scenarios and the simultaneous electromagnetic forces that act on them due to large current transients

(d) Mechanical stresses on the shaft – out of phase synchronisation can exert immense forces on the shaft and without the right ratio of alternator to engine inertias, these torques can cause significant damage to the engine.

Figure 5: Electromagnetic Force Components in Alternator Windings
Conclusion

Figure 6 [4] compares the magnitudes of various forces on generator windings and reinforces the need to understand these forces while designing a robust alternator that is also grid code compliant. S.Narayanan et al [2] have shown that for an alternator to satisfy the steady state requirements of the German grid code, the short-circuit ratio of the alternator needs to be at least 0.45 which puts the value of Xd (main d-axis reactance) at around 2.28 pu. If the same machine had to be then optimized to satisfy fault ride through requirements, a further reduction in Xd is required followed by an increase in the inertia and sub-transient reactances of the machine to ensure robustness and grid code compliance. A high sub-transient reactance to reduce forces on windings also means reduced fault current levels and low starting torques. Modifying winding stiffness to minimize displacements involves re-configuring the windings to eliminate failure modes, modifying bracing and hence potentially modifying alternator packaging. The paper only includes alternator design with the German grid code as an example. There exist however, grid codes in other countries, some of which are more stringent than the German grid codes; this would mean a different alternator sizes for the grids in different countries. Unreasonable requirements such as voltage being depressed for a prolonged time after fault clearing, or overly long fault clearance times, in combination with abnormal operation conditions such as operation on overload or under excitation, might lead to fault ride through conditions that may not be met by commercially viable equipment. There is a need, therefore, for sound engineering judgment as to which conditions should apply any given network. Designing for absolute extremes or unlikely operation conditions is neither economical nor practical. Transmission and distribution operators should therefore set reasonable rules for fault ride through capabilities. An alternator that is meant to be used in a standby generating set should by nature be compact – hence smaller air gap (high power density) and reduced mass (for easy transportation). The introduction of grid code compliance and the proliferation of distributed generation would mean that these alternators that were traditionally used only in standby gensets will now have to become bigger and more robust to be allowed to connect to the grids.

Acknowledgements

The authors would like to thank Chris.J.Whitworth, Robin Jackson, Petr Chmelicek, Param Anpalahan, Abdeslam Mebarki, Steve Allen, Shaun Green and Scott Whiteside of Cummins Generator Technologies for their feedback on the study on grid codes and the discussions that followed on the observations made on alternator sizing. The authors would also like to thank Cummins Generator Technologies for permission to publish this paper.

References


V4 of AMPS Position to support the GC0048T action for a technical explanation to support U,ret of 30%                               page 1               CJWhitworth  04/04/2106

V.ret Clarification …GC0048T… Synchronous Generators…AMPS Position

Overview.

The minimum value for an FRT related retained voltage (U.ret) has been identified as an issue for certain kinds of type B synchronous power generating units, specifically when the prime mover is a reciprocating internal combustion (RIC) engine. Accepting that such units are unlikely to be greater than 5MW, therefore likely to be a low population within the total network scheme, working group GC0048T has asked AMPS to provide a technical explanation to support their request for such synchronous generators to have U.ret set at 30% for a duration of <150ms (FRT event). It may be that type B synchronous generators with RIC prime movers are considered as a special case.

Technical Comment.

1. Present position;

The performance capability requirements set by RfG has introduced major technical changes to a typical synchronous power generating equipment package which until now has been applied to Grid Connect duties. In summary these RfG changes require the incorporation of considerably more materials to achieve enhanced operational functional capability, thus incurring additional cost in the in the following areas;

- Alternator active materials; copper and iron related to electro-magnetic systems.
- Increased spinning inertia of engine + alternator assembly (H).
- Robustness of alternator winding construction.
- Robustness of engine/alternator mechanical driveline and equipment foundation structure.
- Integrated and enhanced control system functions for alternator and engine.
- Boosted generator operational control schemes, protection, metering and communications.
- Reactive VAr dynamic control.
- Exhaustive compliance testing and related approval process.

The above changes have increased the price of an RfG unit by some 40% above that of a typical pre 2015 manufactured G59 related compliant power generation equipment package.

Regarding the capability of the presently developed RfG units, AMPS members have provided stakeholder feedback that such RfG units subjected to ‘unofficial’ testing regimes have the capability to be RfG compliant with the proviso that the U.ret condition is 30% for a duration of <150ms.

There now follows a technical explanation to support why this position has been taken. It is hoped the following will lead to an understanding of the significant performance differences between synchronous generators powered by reciprocating internal combustion (RIC) engines and solid state power electronic based generators. The ideal solution with regard to the adoption of a value for U.ret., is for a special case to be introduced for RIC powered synchronous generation.
Technical Explanation

2. Alternator

A synchronous power generating module must be able to ‘feel’ the network’s ac voltage waveform being applied to the alternator’s stator windings as this is the only way the alternator’s rotor can detect the stator assembly’s related electro-magnetic flux to which the rotor must remain aligned and so hold synchronism with that network’s three phase ac voltage waveform.

An alternator’s rotor does not hold a single point of alignment with the stator winding assembly. It does in fact adopt an arc of angular-bandwidth of relative positional alignment to the stator winding flux; this arc being referred to as the rotor load angle. An operational rotor load angle is directly related to the alternators terminal voltage and electrical output; P.S & Q. The rotor pole position will be in the same relative load angle alignment position for each of the three phases winding groups; presuming symmetrical load conditions. Under asymmetric load conditions the rotor load angle will have an oscillatory dynamic behaviour, with the rotor damper cage working hard to dampen the degree of load angle changes.

Maintaining an ideal rotor load angle becomes compromised if the alternator loses direct control over its terminal voltage level. For example when operating in synchronism with a network supply where the voltage level will not be constant as even during normal operating conditions the network voltage operates over a wide voltage regulation band which may be +/-10%, which at each extreme forces the rotor load angle to notably change.

During network instabilities such as FRT(LVRT), it is known there will be rapid and severe reductions of the voltage level applied to the alternator terminals which in turn will seriously compromise the alternator rotor’s ability to maintain a practical-working load angle and so stay in synchronism.

FRT (LVRT) places demands on the alternator which requires a tight control to be in place of the operating arc span of the rotor load angle. This means the alternator needs to be designed to have increased inherent electro-magnetic stiffness. The rotor will then be held more ‘stiffly’ aligned to, and so more positively locked in synchronism with, the stator related flux driven by the connected network voltage ac waveform.

This ‘stiffening’ is achieved by using an alternator with an electro-magnetic design (EMD) which drives for a low value of Synchronous Reactance (Xd). It is generally accepted that an RfG compliant alternator will need to have Xd <2.0pu.when correlated to the alternators defined rated output of P, S & Q at the nominal value of the identified operating voltage at fundamental frequency. For reference the reciprocal of Xd = Short Circuit Ratio (SCR) so an Xd of 2.0  =  SCR of 0.5

Any reduction in the network voltage level will result in that elements reduced level of generated air-gap flux which means the rotor is forced to operate in an electro-magnetic environment where there is a reduced level of electro-magnetic stiffness and so synchronising alignment attraction.
A critical situation being reached should the network voltage become so low that only a weak level of electro-magnetic attraction is present, which would result in a situation where the rotor’s load angle increases to a point where electro-magnetic attraction becomes even weaker and a loss-of-synchronisation/pole-slip, occurs.

Recapping the above alternator evaluation.
It has been described how the rotor load angle varies with the level of stator winding output P, S & Q. It therefore follows that under allowable bandwidth variations of network voltage which is typically; V.rated +/- 10% limits. That once a steady state condition of network voltage prevails the generating modules control functions will adjust levels of P, S & Q accordingly and correspondingly the rotor load angle will change. But the change will be minimal if the alternator has an EMD where at rated output for V.nom, Xd <2.0pu and so SCR >0.5

Now follows an outline of the critical situation for an RIC powered synchronous generating module.

When considering FRT (LVRT) events the associated prevailing conditions are dynamic in terms of both voltage level and time period for the indicated fault clearance period and the individual U. against t. recovery conditions.
The most severe condition is associated with the initial drop in network voltage to that of the retained voltage (U.ret.) and the associated time period for U.ret as the network protection system secures the fault.
RfG advises that P should be reduced and controlled proportionally to V (U).
However, a prime mover, of the RIC engine type, is unable to reduce the level of mechanical power being applied to the alternator at the same rate that the network has rapidly reduced the voltage being applied to the alternator stator winding. For an expanded explanation of why an RIC engine has a problem to rapidly reduce power: see following para 4.

The net result is that the alternator is suddenly operating with a very low level of electro-magnetic stiffness flux and so attraction force detectable by the rotor. Consequently the rotor load angle will increase under the effect of the following two mechanisms;
A] The reduced voltage has caused the alternators value of Xd to increase by a factor of several times its ideal value of 2.0pu. and very low value of SCR.
B] The prime mover mechanical shaft power is still at the pre-FRT event level, yet the alternator capability to maintain electrical output power by increasing the output current to maintain P about the much momentarily prevailing U.ret is not possible.
See following para 3 for more information.
C] At this point the Inertia Constant (H) needs to be introduced. For if the synchronous generating module has sufficient H, and the time period t.clear is but a short period. Then H will provide the necessary stabilising effect to hold the rotor’s angular position within the acceptable arc of rotor load angle. For a more detailed explanation see the following para 5.
3. Control Systems:

Once in synchronism with the network the generating module control systems are given new roles. The alternators excitation system is changed from voltage control to power factor (pf) control. The engines speed governor becomes the generators output power controller.

Accepting the network will frequently undergo transient-momentary changes of voltage (and quite rapid slew-rate changes of frequency) the now power factor and power control functions will themselves swiftly assess a detected change and move to correct and align to a new steady state voltage level. But these functions have a degree of ‘slugging’ with their output commands, to ensure actual corrections are necessary and then to apply them over a relatively slow period of typically 2-5s in order to ensure they do not cause the synchronous generating module to promote unnecessary additional network instability.

RfG requires any change in network voltage to be recognised and requires the generating module to respond within clearly defined disciplines. With regard to FRT and the related change to network voltage level an RfG generator should change its delivered power level in proportion to the percentage change of the voltage, thus requiring the generator’s integrated controller to have the necessary software functions.

4. Prime Mover considerations;

Under a constant-power mode of operation and a stable network, the shaft power applied to the alternator will perfectly match the alternators rotor/stator air-gap power (torque) demands to enable the stator to deliver the set levels of P, S & Q to the network; whilst naturally taking into account alternator losses. Any gradual change of network voltage level will be recognised and corrected as indicated in 3 above.

However, any sudden step change in the network voltage level, for example a FRT event, will introduce real problems with just how rapidly the prime mover can reduce the level of the pre-FRT shaft-power it applies to the alternator, and so take control over the operating P and so indirectly, S & Q levels.

Achieving a rapid reduction of developed engine power becomes a key performance requirement not just for supporting the alternator to stay in synchronism during the period of securing the fault (140ms being the GB time).

It becomes imperative that as the voltage recovers over a time period the prime mover is able to deliver controlled levels of power proportional to that recovering voltage; under conditions where the voltage will likely have a dynamic rate of recovery.

Considering the most cost effective RIC engine driven generators will operate at 1500rpm (4pole alternator), where a period of 140ms equates to 3.5 shaft revolutions. The engines being a 4 stroke cycle principle means no individual engine-cylinder will have more than one fuel injection event during the 140ms period. How many cylinders will be incorporated within a typical type B, 2.5 MW RfG generating module needs to be considered and the likelihood is 16<20.

At this point the realisation of the practicalities of rapidly reducing RIC engine power becomes apparent when considering: the finite time taken to recognise an FRT event,
then issue the command to reduce the quantity of injected fuel, and then actually achieve much reduced levels of combustion chamber developed power.

5. **Inertia Constant (H)**
A typical pre 2015 G59 compliant synchronous generating module would likely have an inertia constant of; \( \sim 0.8s \).
The introduction of RfG requirements and required FRT(LVRT) performance initiated the need to reconsider the value of \( H \) against the role it needed to play with supporting the alternator rotors need to stay in synchronism under an FRT where the network voltage’s level of electro-magnetic attraction was very weak and the RIC engine’s level of applied shaft power was very high.

Decisions regarding just what level of \( H \) should be incorporated within a synchronous generating module, needed to take into account two situations.

I ] The practicalities of where to put the necessary rotating mass 
II] Excessive \( H \) introducing mechanical drive line stress along with rotor load angle instability during a severe slew-rate over short-time RoCoF event.

Eventually a compromise was found and the required value of \( H \) for an RfG compliant synchronous generating module is considered to be typically 1.3s

This value of \( H \) becomes critical with regard to the FRT related duration of the \( t.\text{clear} \) time period. **This is why the AMPS position regard \( t.\text{clear} \) is set at <150ms.**

6. **Setting U.ret set at 30%**
During the early days of RfG’s development it was generally thought that for embedded LV generators the local network system would have a retained voltage of some 40<50% based on inherent characteristics of local LV networks even when an FRT event occurred in relatively close >200kV transmission systems.
The National Grid (NG) shared Future Energy Scenario (FES) and related system planning strategy work has now changed several aspects of this initial understanding just how a future GB network will behave, even at LV levels, during an FRT event. The latest thinking being that it LV system U.ret will likely be 30<40% for the 140ms associated with securing the fault.
This revised understanding, thankfully shared by the NG planning group, has been considered by AMPS members and has led to reappraising the technical capability of generators intended for the RfG application. This review has focused on the alternators inherent saliency along with the need for revised control systems with more closely integrated alternator excitation and engine power control functions perhaps even with some form of ‘event’ predictability based on system operators real-time knowledge of sensed network behaviour.
To support the AMPS position of requesting that U.ret is set no lower than 30% for RIC engine driven synchronous generating modules the following examples of where this threshold level is being used now follow.

Item 1;

![Figure 8](image)

**Figure 8 - Low voltage ride through capability for directly coupled generating technology**

Item 2;
Attached as Annex 1
Cummins Generator Technology White Paper which describes Fault Ride Through effects on alternators connected to the grid.
Within the document the case is made for having U.ret set at 30% for alternators to be driven by RIC engines for synchronous generating modules.

Item 3;
Attached as Annex 2
A technical explanation which considers a Synchronous Generator and Retained Voltage levels against the principle of a Power Angle Curve. This document outlines the challenges of maintaining synchronism when the network voltage reduces below a critical level where engine shaft power torque exceeds the generator’s air-gap torque as a consequence of the reduced network voltage; the aftereffect being loss-of synchronism/pole-slip.
The AMPS Position:

It is hoped this technical explanation provides the necessary justification to support the AMPS position that RIC powered synchronous generating modules should not be required to comply with a $U_{ret}$ below 30% for a $t_{clear}$ duration period exceeding 150ms.

AMPS members have provided feedback which supports the above outlined position. It has not been possible to provide supporting test data as each participating AMPS member advised the need to protect their RfG intended product designs and specific performance capability. In the case of partnership developments between manufactures of engines, alternators, control systems and protection schemes these parties are bound by Non-Disclosure Agreements not to reveal any product incorporated ‘special’ features and most importantly share specific cost variations and proposed market prices.

Submitted on behalf of AMPS by:

Chris J Whitworth
AMPS Technical Specialist
AMPS member’s stakeholder feedback related to the GC0048T proposal for U.ret change from 0.3pu down to 0.15pu.

1. AMPS members remain resolved that the U.ret related document* - which advises a 0.3pu U.ret for a duration <150ms - still represents their experienced view of what is realistically achievable without Loss of Synchronisation for a type B SPGM powered by an RIC engine where the total SPGM equipment will typically have an inertia in the region of 1.2s.

*(05/04/2016. U.ret Clarification …GC0048T… Synchronous Generators…AMPS Position).

2. Large companies manufacturing SPGMs have the ability to develop bespoke combinations of prime-movers and alternators jointly controlled by a single encompassing regulator to form a special SPGM able to meet a U.ret of 0.15pu, but the end product is complex and costly. The consequence is that small companies presently involved with SPGM OEM products will not have the necessary special equipment, technology and required development budgets. This will result in a loss of a competitive business base for type B SPGMs and therefore contrary to the ENTSOe objective of facilitating a competitive energy market.

3. Good judgment must be applied to ensure evidence based information supports the need for a blanket adoption of a U.ret as low as 0.15pu. Here the route may include a NGET (Ben Marshall) scenario-study based input. Without such evidence there is a risk that the RfG adoption process will be challenged regarding unnecessary complication leading to unjustified over specifying which results in adding unnecessary cost to every type B - SPGM.

4. A key objective of RfG has been to identify key performance areas and set legal requirements across an operating parameter range. In order to support the enabling of a competitive energy market introduces a need to duly consider the adoption of such performance values at the legal minimum requirements for the majority of the network area, rather than the most stringent requirements for the minimum area of weak network?

5. For many technical reasons the type B diesel engine powered SPGM’s will provide flexible P,Q&S input to the network plus most effectively support the network during system disturbances and post fault recovery. So is it not ill-considered to introduce stringent worst case scenario requirements which then discourage the availability of cost-effective, fuel efficient, low emission SPGMs by over specifying requirements just to meet the needs of a local networks bespoke shortcoming.

The above has been collated by Chris Whitworth, AMPS Technical Specialist….22nd September 2016.
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**Comments**

- **Consultation Phase**
  - Prevalent voltage during fault.
  - Through agreement, the power generating unit, connected to the system, should have a capability of voltage ride through.
  - **Voltage Ride Through Capability** (16.3.a) 3 parameter Agree
    - **Article 4.2.5.2**
      - Voltage profile at kV 43 Uclear Uret Uret 16.3.a D
      - Voltage profile at 16.3.a
      - Voltage profile at kV 43 Uclear Uret Uret 16.3.a D
      - Voltage profile at 16.3.a
    - **Article 4.4.2**
      - Voltage profile at 43 Uclear Uret Uret 16.3.a D
      - Voltage profile at 16.3.a
      - Voltage profile at kV 43 Uclear Uret Uret 16.3.a D
      - Voltage profile at 16.3.a
    - **Article 4.4.6**
      - Voltage profile at 43 Uclear Uret Uret 16.3.a D
      - Voltage profile at 16.3.a
      - Voltage profile at kV 43 Uclear Uret Uret 16.3.a D
      - Voltage profile at 16.3.a
    - **Article 55**
      - Voltage profile at 43 Uclear Uret Uret 16.3.a D
      - Voltage profile at 16.3.a
      - Voltage profile at kV 43 Uclear Uret Uret 16.3.a D
      - Voltage profile at 16.3.a

- **Voltage during fault**
  - During voltage dips, i.e., when the voltage is below 0.9 p.u., the system should include several features:
    - **Symmetrical injection**
      - For active power, for several seconds, the current will be greater than the previous value.
      - During voltage recovery, the current will be greater than the previous value.
      - The power factor will be greater than one.
    - **Non-symmetrical injection**
      - For active power, for several seconds, the current will be greater than the previous value.
      - During voltage recovery, the current will be greater than the previous value.
      - The power factor will be greater than one.

- **Operational Requirements**
  - For offshore generation, the power factor will be greater than one.
  - For offshore generation, the power factor will be greater than one.
  - For offshore generation, the power factor will be greater than one.
  - For offshore generation, the power factor will be greater than one.

- **System Security**
  - For offshore generation, the power factor will be greater than one.
  - For offshore generation, the power factor will be greater than one.
  - For offshore generation, the power factor will be greater than one.
  - For offshore generation, the power factor will be greater than one.