Stage 02: Workgroup Consultation

Grid Code

GC0100 EU Connection Codes GB Implementation – Mod 1

What stage is this document at?

01	Proposal Form
02	Workgroup Consultation
03	Workgroup Report
04	Industry Consultation
05	Report to the Authority

This modification will set out within the Grid Code the following compliance obligations in the EU Connection Codes:

1. Scope and applicability of the RfG, DCC and HVDC requirements for GB users
2. Set the four Type (A-D) MW banding levels for GB, as required in RfG
3. Set the GB Fast Fault Current Injection parameters, as set out in RfG
4. Set the GB Fault ride through requirements, as set out in RfG and HVDC

This document contains the discussion of the Workgroup which formed in June 2017 to develop and assess the proposal. Any interested party is able to make a response in line with the guidance set out in Section 8 of this document.

Published on: **11 September 2017**

Length of Consultation: **15 working days**

Responses by: **2 October 2017**

High Impact:
Developers of: New generation schemes (800 Watts capacity and up), new HVDC schemes (including DC-connected Power Park Modules); GB System Operator; Distribution Network Operators

Medium Impact:
Transmission Owners (including OFTOs); Operators of existing generation, HVDC schemes considering modernisation

Low Impact:
None

Contents

Any questions?

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Timetable

The Panel have agreed the following timetable:

Workgroup Consultation issued to the Industry	11 September 2017
Modification concluded by Workgroup	7 November 2017
Workgroup Report submitted/presented to the Grid Code Review Panel	7/15 November 2017
Code Administration Consultation Report issued to the Industry	17 November 2017
Draft Final Modification Report presented to the Grid Code Review Panel	12 December 2017
Grid Code Review Panel Recommendation Vote	20 December 2017
Final Modification Report issued the Authority	5 January 2018

About this document

This document is a Workgroup consultation which seeks the views of Grid Code and interested parties in relation to the issues raised by the Original GC0100 Grid Code Modification Proposal which was raised by Richard Woodward, National Grid and developed by the Workgroup. Parties are requested to respond by **5pm** on **2 October 2017** to grid.code@nationalgrid.com using the Workgroup Consultation Response Proforma which can be found on the following link:

http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/Modifications/GC0100/

Document Control

Version	Date	Author	Change Reference
0.1	11 July 2017	National Grid	Draft Workgroup Report
0.2	11 September 2017	Workgroup	Workgroup Consultation to Industry

1 Summary

1.1 This report aims to outline the discussions had at workgroup in respect of its scope; set out the proposals to address the solution from the proposer and possible alternative options, and provide supporting justification respectively

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1.2 GC0100 was proposed by National Grid and was submitted to the Grid Code Review Panel for their consideration on 30 May 2017 and the Distribution Code Review Panel.

1.3 The Grid Code Review Panel decided to send the Proposal to a Workgroup to be developed and assessed against the Grid Code Applicable Objectives.

1.4 Section 2 (Original Proposal) and Section 3 (Proposer's solution) are sourced directly from the Proposer and any statements or assertions have not been altered or substantiated/supported or refuted by the Workgroup. Section 4 of the Workgroup contains the discussion by the Workgroup on the Proposal and the potential solution.

1.5 The Grid Code Review Panel detailed in the Terms of Reference the scope of work for the GC0100 Workgroup and the specific areas that the Workgroup should consider. This can be found in Annex 1.

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2 Original Proposal

Section 2 (Original Proposal) is sourced directly from the Proposer and any statements or assertions have not been altered or substantiated/supported or refuted by the Workgroup. Section 4 of the Workgroup Consultation contains the discussion by the Workgroup on the Proposal and the potential Solution.

What

2.1 Full sections of the Grid Code, for example the Connection Conditions (CCs), and the Distribution Code and its daughter documents, will need to be extended to set out the new EU standards to which impacted users will need to comply with.

2.2 This will be a combination of completely new requirements inserted into the Grid Code and Distribution Codes, or adjustments/continuation of corresponding existing GB requirements to line up with equivalents in the new EU codes.

2.3 In general the fast fault current injection and Fault ride through requirements for HVDC Connections (Title II) would be the same as the GB proposals for Type D Power Park Modules.

2.4 For DC Connected Power Park Modules the fast fault current and Fault ride through requirements would be the same as Type D Power Park Modules but an allowance would be made for alternative arrangements depending upon technology type but any such requirement would still need to be within the framework of the RfG Code.

2.5 For a slightly more detailed overview of the proposals and an Executive Summary, the reader is encouraged to refer to Section 3.

Why

2.6 Guidance from BEIS and Ofgem was to apply the new EU requirements within the existing GB regulatory frameworks. This would provide accessibility and familiarity to GB parties, as well as putting in place a robust governance route to apply the new requirements in a transparent and proportionate way.

2.7 This modification needs to be undertaken in timely manner to ensure affected users are aware of their compliance obligations - particularly in relation to procurement of equipment, testing and operational requirements. This modification is also therefore, critical to facilitate/demonstrate member state compliance to these three EU Network Codes.

2.8 This proposal is one of a number of proposals which seek to implement relevant provisions of a number of new EU network codes/guidelines which have been introduced in order to enable progress towards a competitive and efficient internal market in electricity.

2.9 Some EU network guidelines are still in development and these may in due course require a review of solutions developed for codes that come into force beforehand. The full set of EU network codes are:

- Regulation 2015/1222 – Capacity Allocation and Congestion Management (CACM) which entered into force 14 August 2015
- Regulation 2016/1719 – Forward Capacity Allocation (FCA) which entered into force 17 October 2016
- **Regulation 2016/631 - Requirements for Generators (RfG) which entered into force 17 May 2016**
- **Regulation 2016/1388 - Demand Connection Code (DCC) which entered into force 7 September 2016**
- **Regulation 2016/1447 - High Voltage Direct Current (HVDC) which entered into force 28 September 2016**
- Transmission system Operation Guideline (TSOG) - entry into force anticipated Summer 2017
- Emergency and Restoration (E&R) Guideline - entry into force anticipated Autumn 2017

2.10 RfG, DCC and HVDC were drafted to facilitate greater connection of renewable generation; improve security of supply; and enhance competition to reduce costs for end consumers, across EU member states.

2.11 These three codes specifically set harmonised technical standards for the connection of new equipment for generators, demand, and HVDC systems (including DC-connected Power Park Modules respectively).

2.12 Significant work to progress GB understanding of the codes and consider the approach for implementation has been undertaken in Grid Code/Distribution Code issue groups GC0048 (RfG); GC0090 (HVDC) and GC0091 (DCC).

2.13 These have been widely attended, including DNOs and smaller parties. Additional stakeholder holder engagement has been undertaken to ensure the impacts of the three EU codes is understood, as well as to provide an opportunity to feed into the approach.

2.14 Through proposing these modifications under Open Governance, we will finalise the proposals; and undertake a final industry consultation to confirm they are appropriate, before submitting papers to Ofgem to request a decision.

How

2.15 With the support of the industry, we will use this modification to finalise proposals to apply the EU Connection Codes requirements, before consulting with the wider industry and submitting to Ofgem for a decision.

2.16 Previously, Grid Code and Distribution Code issue groups were formed (GC0048, GC0090, GC0091) to:

1. Comprehensively review the code to form a local interpretation of the requirements;
2. Undertake a mapping between the EU and GB codes to understand the extent for possible code changes;
3. Form proposals, which will now be taken forward as formal modifications.

Proposals:

- GB Banding levels for Type A, B, C and D
- GB requirement for Fast Fault Current Injection for Generators and HVDC systems (including DC-Connected Power Park Modules)- including multiple options for delivering this capability requirement for Fault ride through for Generators and HVDC systems (including DC-Connected Power Park Modules) – represented in voltage against curves
- Proposals for amendments to the Distribution Code and its associated Engineering Recommendations that implement the above requirements for users connected to Distribution systems.

3 Solution

Section 3 (Solution) is sourced directly from the Proposer and any statements or assertions have not been altered or substantiated/supported or refuted by the Workgroup. Section 4 of the Workgroup Consultation contains the discussion by the Workgroup on the Proposal and the potential Solution.

3.1 Scope and applicability of the RfG, DCC and HVDC Requirements for GB User's

The applicability to 'new' Users of the three EU connection Network Codes is explicitly set in the legal text. In limited circumstances the EU connection Network Codes may also be applicable to 'existing' connected Users. Therefore no interpretation is needed to apply these requirements.

Draft legal text for Users to determine their status as 'existing' (i.e. not by bound the EU Connection Codes) and 'new' (i.e. bound by the EU Connection Codes) is set out in Annex 2 & 3. Please note that this is draft legal text that will be finalised following the closure of the Workgroup Consultation.

This legal text includes the potential for 'existing' users to be bound by the EU requirements if they undertake modernisation or replacement of equipment to such an extent that a new connection agreement is required or a Cost Benefit Analysis is undertaken in accordance with the EU connection Network Codes.

3.2 Set the four RfG Type (A-D) MW banding levels for GB

	Type A	Type B	Type C	Type D
Connection Voltage:	<110kV	<110kV	<110kV	≥110kV
Unit MW	800W – 0.999MW	1MW-9.999MW	10MW-49.999MW	50MW+

Justification for nominated values

System Operators need to continue to define requirements which are reasonable, efficient and proportionate against a rapidly changing Generation background. RfG mandates TSOs to propose and justify the appropriate and necessary generation banding thresholds for their area of operation.

The proposal would apply the same technical requirements across the whole of GB. In view of the growth in embedded small scale generation witnessed over the last few years, the technical requirements applicable in the North of Scotland and Offshore should be equally applicable, for new generation wherever they are connecting across the whole of GB. It is expected this issue would have needed to have been addressed under GB code governance in the near future, irrespective of the introduction of the EU Network Codes.

In order for the GB System Operator and Transmission licensee's to discharge their obligations to permit the development, maintenance and operation of a reasonable, efficient and proportionate system for the transmission of electricity and to embody the high levels of network reliability and operation, the GC0100 proposer believes these proposed generator banding levels provide a reasonable compromise between the needs of the system against the minimum costs to which newly connecting Generators are exposed to.

In comparing the banding level proposals for nearby synchronous areas, the Continental Europe power system is of the order of ten times larger than the GB System. The majority of European TSOs for Member States in Continental Europe are proposing generator banding levels lower than the maximum permitted under RfG, many of which, if not being comparable with the proposed GB levels, are lower than that proposed for GB. The proposer therefore believes there is a greater likelihood of harmonisation with Continental European neighbours with a lesser banding level than the maximum (noting that NRA approval is required to set these levels).

The GC0048 workgroup previously considered the pros and cons of applying a low banding level, similar to that of the Irish synchronous area. Whilst the proposer believes a case could be made for similar values in GB, they accept the points raised by the industry during the previous consultation phase (please see Annex 7), and so will not be proposing these in GC0100.

In regards to specifics of the proposer's solution for banding, a Type B/C Threshold of 10MW for GB would provide a greater proportion of Generation inherently capable of contributing to frequency response, noting that commercial facilitation is not in the scope of RfG to consider, but a factor when it comes to cost.

There is a close relationship between Fast Fault Current Injection (FFCI) and the Fault Ride Through parameters.

Without FFCI as proposed, the proposal will need to lower the value of U_{ret} (from 0.1pu to 0.05pu) and even then, this value would only appropriate in the short term before a further review is likely to be required. There is also a cost of tripping synchronous generation in a higher band (10MW – 50MW) which could result in a potential increase in holding additional reserve costs alone of £9 million / annum.

Following stakeholder discussions a U_{ret} of 0.3pu for newly connecting Type B Synchronous plant is recommended by the Proposer (See Reference [2]). Larger Synchronous Generators, e.g. those derived from steam, gas or hydro turbines are not believed to suffer from the same Fault Ride Through issue. A Type B / C Threshold of 10MW would enable Band B Synchronous Generators derived from reciprocating engines to satisfy the proposed Fault Ride Through requirements without presenting system security concerns.

The GB System Operator feels that adopting these values are the most equitable level balancing the needs of the system and obligations of users to support, without incurring material compliance costs.

3.3 Set the RfG Fast Ride Through parameters for GB

Introduction

The RfG Fault Ride Through requirements for Power Generating Modules are detailed in Article 14(3), Article 16(3) and Article 17(3).

Unlike the GB Grid Code, the RfG requirements segregate the requirements between Synchronous Plant and Asynchronous Plant. The requirements also differ dependent on RfG Generator 'Type', with varying requirements applying between Type B, C and D Power Generating Modules connected below 110kV and Type D Power Generating Modules connected at or above 110kV.

A further complication of the RfG structure is that the requirements are incremental, building up from Type A (the least onerous) to Type D (the most onerous). For example, all the requirements applicable to Type C Power Generating Modules also include the requirements applicable to Type A and B Power Generating Modules

The fundamental RfG Fault Ride Through principles are defined for Type B Power Generating Modules and above (Article 14 (3)). The requirements applicable to Type D[1] Power Generating Modules connected at 110kV or above are simply an extension of the Type B requirements but with more onerous voltage against time parameters.

The Fault Ride Through requirement is defined by a voltage against time profile which applies at the new Power Generating Module connection point.

The voltage against time profile describes the conditions in which the newly connected power generating module must be capable of remaining connected to the network and continuing to operate stably after the power system has been disturbed by secured faults on the Transmission system.

[1] And Type C.

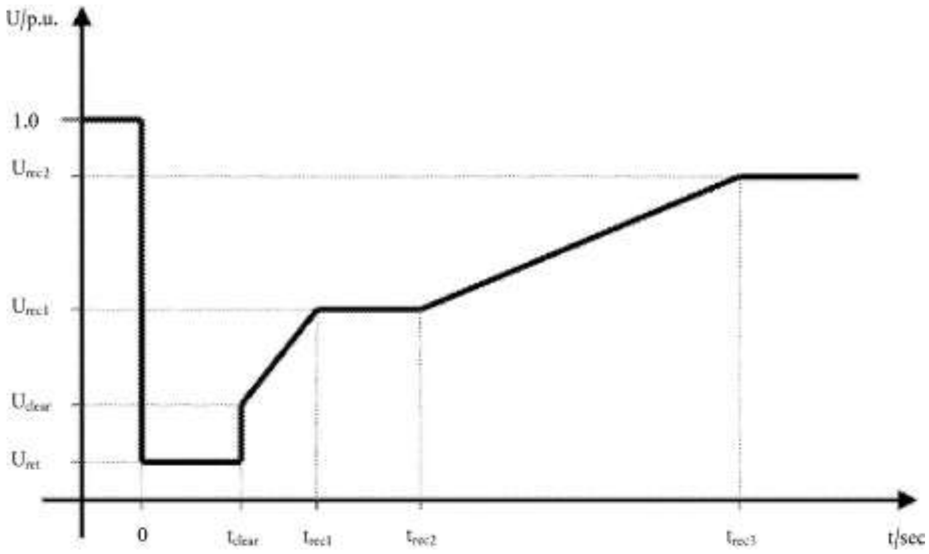


Figure 5.1 – Voltage Against Time Curve – Reproduction of RfG Fig 3

The Voltage against time curve is designed to express the lower limit of the actual phase to phase voltage at the Connection Point during a symmetrical fault, as a function of time before, during and after the fault.

3.4 Voltage against time curve for a Type D Synchronous Power Generating Module connected at or above 110kV

For a Type D Synchronous Power Generating Module, the range of voltage limits available for the TSO to select in accordance with Article 14(3)(a) – Figure 5.1 which is reproduced below as Table 5.1.

Voltage parameters (pu)		**Time parameters (seconds)**	
U_{ret}:	0	t_{clear}:	0,14-0,15 (or 0,14-0,25 if system protection and secure operation so require)
U_{clear}:	0,25	t_{rec1}:	t_{clear}-0,45
U_{rec1}:	0,5-0,7	t_{rec2}:	t_{rec1}-0,7
U_{rec2}:	0,85-0,9	t_{rec3}:	t_{rec2}-1,5

Table 5.1 – Extract of Table 7.1 from RfG

In accordance with the RfG requirements, each TSO is required to make publicly available the pre and post fault conditions for Fault Ride Through in terms of:-

- The pre-fault minimum short circuit capacity at the Connection Point expressed in MVA
- The pre-fault operating point of the power generating module expressed as active power output and reactive power output at the connection point and voltage at the Connection Point (i.e. Maximum MW output, Full MVAr lead and typical operating voltage).
- The post fault minimum short circuit capacity at the connection point expressed in MVA.

It is envisaged that general maximum and minimum short circuit data would be included in the Electricity Ten Year Statement (ETYS) and in the case of Transmission-connected generation the exact calculated figures at the Connection Point for newly connecting Users would be specified in Appendix F of the Bilateral Connection Agreement.

For distribution connected Power Generating Modules it is envisaged that DNOs will publish appropriate typical figures (probably in the Long Term Development Statements) with more site specific values produced on request.

In addition Article 14(3)(vi) states the protection settings of the new Power Generating Facility should not jeopardise Fault Ride Through performance which includes the under voltage protection at the Connection Point.

3.5 Determination of RfG Voltage against time parameters as applicable to Type D Synchronous Power Generating Modules connected at or above 110kV

The GB RfG Fault Ride Through parameter is shown in Table 5.2 and represented graphically in Figure 5.5.

Voltage Parameters [pu]		Time Parameters [seconds]	
U_{ret}:	0	t_{clear}:	0.14
U_{clear}:	0.25	t_{rec1}:	0.25
U_{rec1}:	0.5	t_{rec2}:	0.45
U_{rec2};	0.9	t_{rec3}:	1.5

Table 5.2 – Proposed GB Parameters for the Fault Ride Through Capability of a Type D Synchronous Power Generating Module connected at or above 110kV

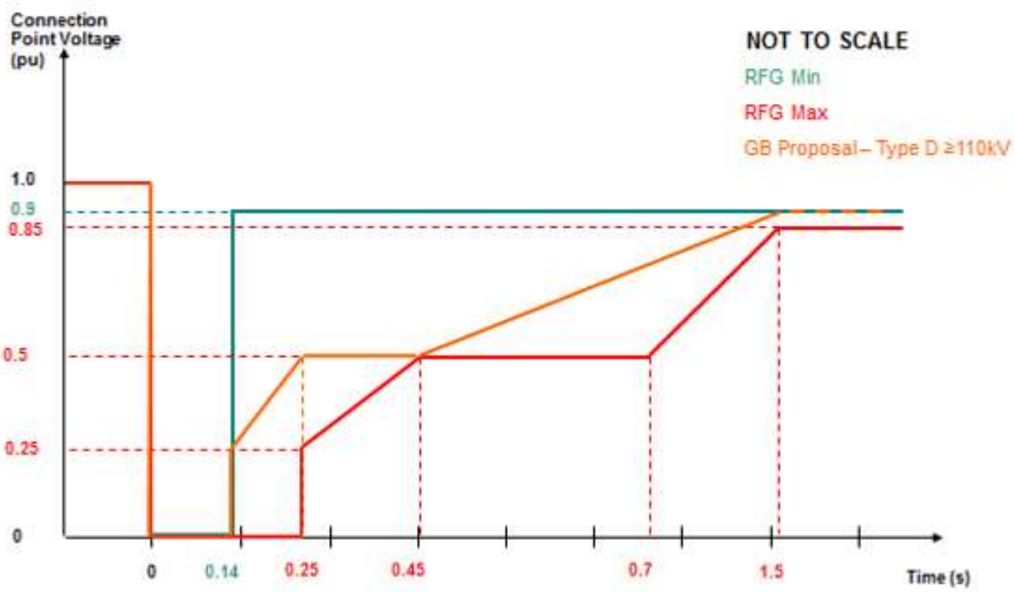


Figure 5.5 – Proposed GB Voltage against time curve for a Type D Synchronous Power Generating Module connected at or above 110kV

It is worth noting that the voltage against parameters for Type D Power Generating Modules connected at or above 110kV (RfG Tables 7.1 and 7.2) are different to those for Type D Power Generating Modules connected below 110kV (RfG Tables 3.1 and 3.2), in which case the latter fall into the same range as values specified for Type B and C Power Generating Modules.

It should further be noted that the parameter ranges vary depending upon the type of Power Generating Module (i.e. a Synchronous Power Generating Module or Power Park Module).

Taking the extreme ends of these parameter ranges (Table 5.1 above), it is possible to plot a graph showing the parameter ranges available to TSO's at a National level. This is shown in Figure 5.2 below.

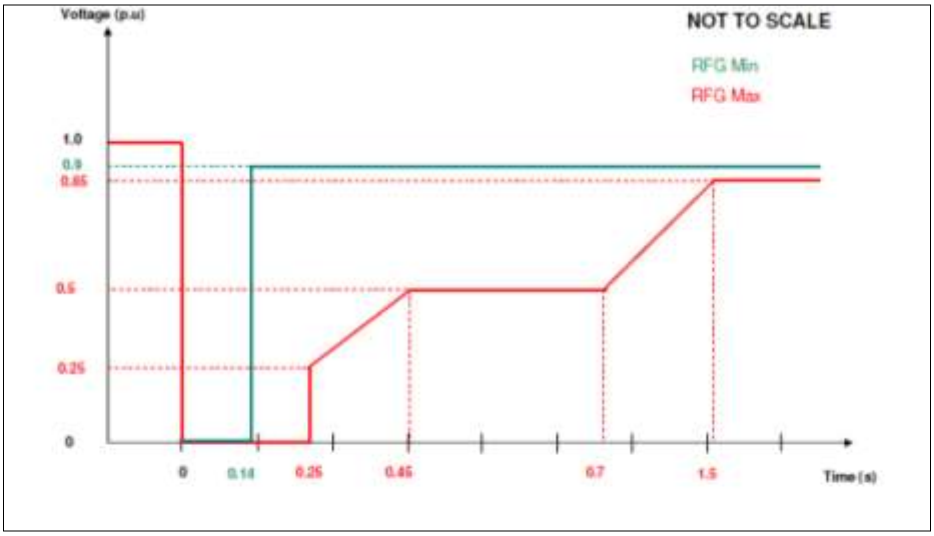


Figure 5.2 – Range of RfG Voltage Against Time Parameters available to TSOs

The green curve ('RFG Min') refers to the minimum voltage against time curve. Under this case, the post fault voltage profile would require a reasonably stiff system. The implication being that Generator tripping would be permitted under the least onerous of conditions. On the other hand, the red curve is the most onerous requiring the generating unit to remain connected and stable for quite severe post fault voltage recovery conditions.

At first glance and reading RfG, it would appear that the TSO should be able to select a voltage against time profile anywhere between the Green and Red line. In practice this is not strictly true as the range of parameters in Table 7.1 of RfG (Table 5.1) do limit the ability of the TSO to select certain values between these ranges. These restrictions are shown in Figure 5.3 below. This limitation was also reflected back to ENTSO-E but it is not believed it will cause an issue.

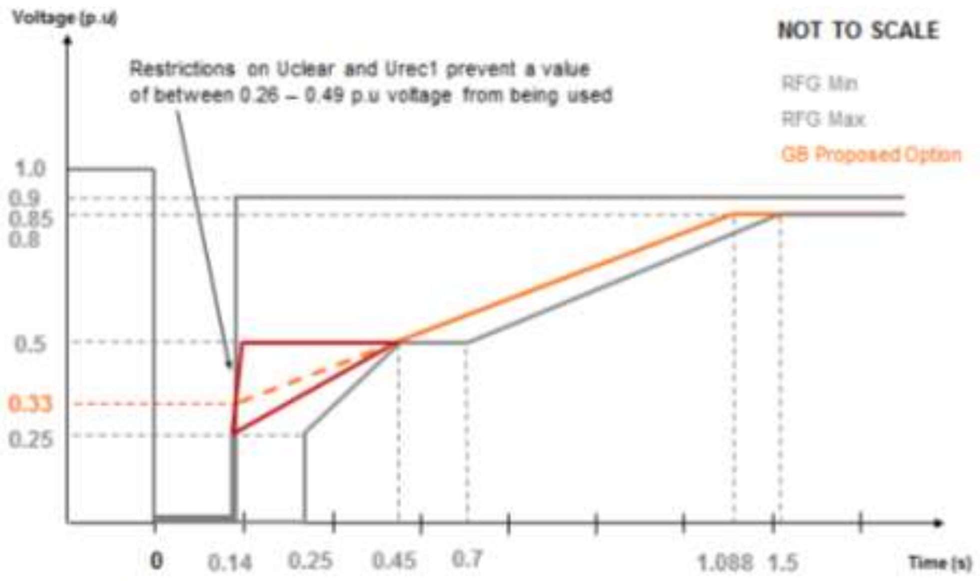


Figure 5.3 – Limitations on voltage against time curves

A Generator has to ensure the post fault voltage profile is maintained above the defined voltage against time curve. The general understanding is that the post fault voltage profile will be dictated largely by the System rather than the performance of the Power Generating Module.

For the purposes of compliance, a 140ms three phase short circuit fault would be applied at the nearest Transmission system Connection Point for the Generator. Provided the Generator remains connected and stable and the post fault voltage profile remains above the defined voltage against time curve the Power Generating Module would be deemed compliant. In the event that the Power Generating Module were to pole slip, then the post fault voltage as seen from the Generator would result in oscillations beyond the defined voltage against time curve under which generator tripping would be permitted.

Under CC.6.3.15.1(a) of the GB Grid Code, currently a directly connected existing generator would be required to remain connected and stable for a solid three phase short circuit fault for up to 140ms in duration. In other words, the Generator could be exposed to zero volts for 140ms. Translating this into the RfG voltage against time curve therefore sets the value of Uret to zero and tclear to 0.14 seconds.

The subsequent points on the voltage against time curve are more complex to determine. In general, the post fault voltage profile is more a function of the pre and post fault short circuit level at the connection point rather than the characteristics of the Synchronous Power Generating Module itself. However, it is important that an achievable characteristic is set, which on one hand is not so onerous that it could result in the generator to pole slip whilst on the other that is so lenient that the generator would be permitted to trip for minor faults.

In practice, an assessment of stability will be made at the Transmission Connection application stage. The Transmission system Owner will design the Transmission Network in accordance with the requirements of the Security and Quality of Supply Standards (SQSS). During the application stage, stability studies will be run which will detail the specification of the excitation system (e.g. onload ceiling voltage and rise time). This specification being an important criterion upon which the stability requirements are assessed.

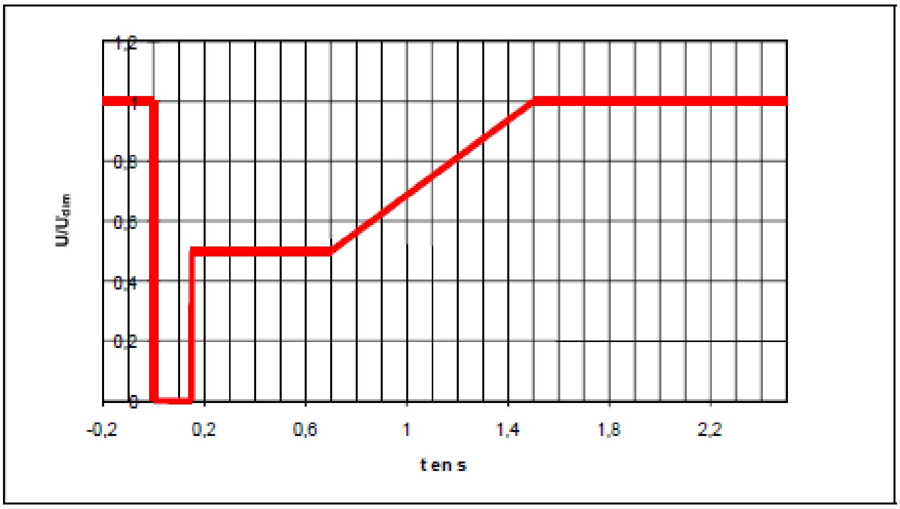
So far as the voltage against time curve is concerned, the curve needs to cater for credible system events but not those which would either be unduly pessimistic or beyond the requirements of the SQSS as these are covered under Mode B faults (i.e. faults in excess of 140ms which are currently required in the GB Code but not in RfG). As part of this work it is proposed to adopt the RfG requirements (which apply only to secured faults) and retain the GB provisions for faults in excess of 140ms which was revised following Grid Code Consultation GC0062.

The proposer believes vitally important that the Generator does not set its under-voltage protection settings to the same value as the voltage against time curve as this would result in premature tripping. As such, the voltage against time curve needs to consider credible voltage variations caused by high post fault MVAr demands.

Returning back to the derivation of the voltage against time curve, the value of Uclear is fixed at 0.25. As this marks the start of the voltage recovery (i.e. immediately on fault clearance) this point would also take place at 140ms, and therefore is set by tclear.

The next stage is to consider the remaining parameters of the voltage against time curve, Urec1, Urec2, trec1, trec2 and trec3. These are more complex due to the potential arbitrary nature of the points that can be selected for the voltage against time curve. Taking into account the effect of post fault voltage oscillations, particularly where there may be high MVAr demands and the analysis undertaken, the voltage against time curve needs to be robust enough to cater for system disturbances cleared in main protection operating times whilst ensuring it is not sufficiently onerous that the requirement is not achievable.

An example of the current voltage against time curve applied by the French TSO (RTE) is shown in Figure 5.4. In summary this requires the generator to withstand a 100% voltage dip for a period of 150ms, a 50% voltage dip for a further 550ms (total 700ms) and restoration to 1.0pu volts a further 800ms (total 1500ms) later.



Gabarit de creux de tension pour les réseaux d'interconnexion

Figure 5.4 – French RTE Low Voltage Ride Through Voltage Against Time Curve

In deriving a GB voltage against time curve, there is always a concern under high MVAr demands that the post fault voltage could struggle to return to 0.5 pu at 140ms instantaneously. On this basis and to take this effect into account, the Proposer recommends that the value of Urec1 is set at 0.5pu and trec1 set at 0.25s.

Should the voltage still struggle further to recover, then a plateau needs to be introduced but it becomes fairly straight forward to determine these values in terms of voltage and time. As a plateau is introduced the value of Urec1 remains at 0.5 pu and the time trec1 would need to be at or less than the breaker fail operating time of typically 500ms.

Based on the fact that the Mode B Fault Ride Through requirements are considered separately from RfG and the study work contained in Annex 5 of Reference [1], it was considered, by the Proposer, that a value of 450ms would be appropriate for trec2.

As Mode B faults are designed to cover unsecured faults which could result in potentially small voltage deviations (say a voltage dip of 0.15pu; retained voltage 0.85pu) for a considerable length of time (e.g. 3 minutes) and based on the analysis contained in Appendix 5 of Reference [1], it seems reasonable to the Proposer, that the voltage against time curve should be set to a condition of 0.9pu at 1.5 seconds. This therefore sets the time trec3.

Based on the analysis completed and the approach adopted internationally, a value of 1.5s for trec3 would not, according to the Proposer, be seemed to be unreasonable. This is not however to be confused with compliance where a solid three phase short circuit fault should be applied for 140ms with the post fault voltage returning to a value of between 1.0 pu - 0.9 pu being agreed between the User and National Grid.

3.6 **Determination of RfG Voltage against time parameters as applicable to Type C and D Synchronous Power Generating Modules connected below 110kV**

The principles in deriving the voltage against time curve for Type C and D Synchronous Power Generating Modules connected below 110kV are broadly the same as those for Type D Synchronous Power Generating Modules connected at 110kV or above other than the parameter ranges specified in the RfG code.

Article 14(3)(a)(i) - Table 3.1 defines the voltage against time parameter ranges for Type B, C and D Synchronous Power Generating Modules connected below 110kV which is reproduced below as Table 5.3.

Voltage parameters [pu]		Time parameters [seconds]	
U_{ret}	**0.05 – 0.3**	t_{clear}	**0.14 – 0.15** (or 0.14 – 0.25 if system protection and secure operation so require)
U_{clear}	**0.7 – 0.9**	t_{rec1}	t_{clear}
U_{rec1}	U_{clear}	t_{rec2}	t_{rec1} **– 0.7**
U_{rec2}	**0.85 – 0.9 and** $\geq U_{clear}$	t_{rec3}	t_{rec2} **– 1.5**

Table 5.3

Representing Table 5.3 in graphical format results in Figure 5.6:

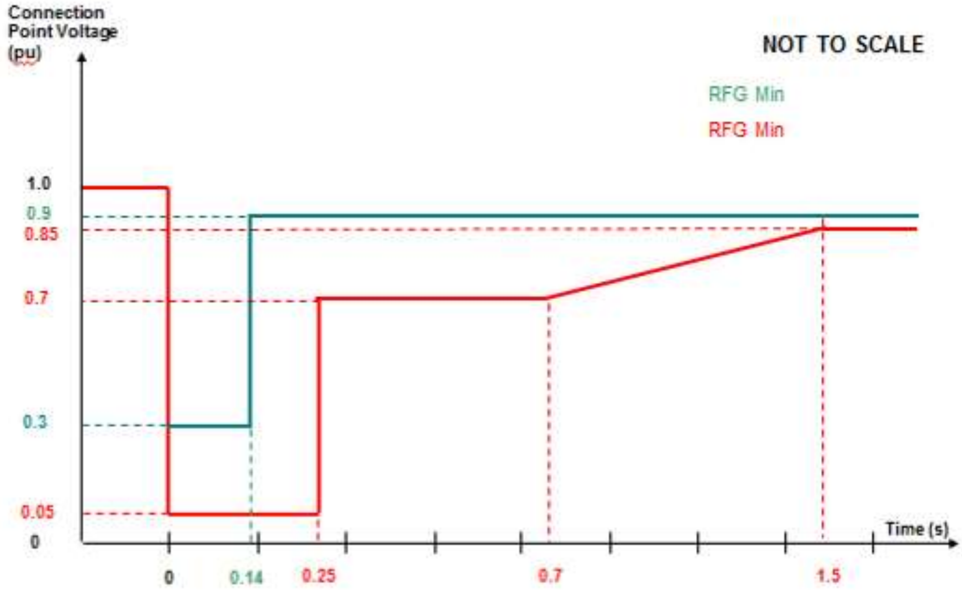


Figure 5.6 – Available range of voltage against time curves for Synchronous Power Generating Modules connected below 110kV

Determination of the proposals for the Type C and Type D requirement for Synchronous Power Generating Modules connected below 110kV follows a similar methodology for Type D Synchronous Power Generating Modules connected at or above 110kV.

The following criteria have been used:

t_{clear}	set at 140ms based on maximum protection operating times for a Transmission system fault
U_{ret}	set at 0.10pu. This value has been set at 0.1pu based on the fast fault current injection studies referred to in section 3 of this report. If the volume of fast fault current is not delivered as proposed in Section 3 of this report, consideration would have to be given to reducing U_{ret} to 0.05pu.
U_{clear}	fixed to the lower of 0.7pu in line with RfG requirements. Based on system studies run under the GC0062 Grid Code Workgroup (Annex 4 Reference [1]) this is believed to be achievable
t_{rec2}	set to 0.45s. System studies (GC0062 Workgroup Report – Annex 4 Ref [1]) demonstrated pole slipping would tend to occur for longer time durations than 450ms at 0.5pu).
U_{rec2}	set to 0.9pu the upper limit based on steady state recovery voltages
t_{rec3}	set to 1.5 seconds, based on protection having operated within this time, the ability of synchronous plant to withstand longer duration high impedance faults and study work demonstrated that synchronous plant does generally not have a problem for retained high voltages over a longer time frame

Transposing the values defined above into a graphical form and plotting these between the maximum and minimum RfG values results in Figure 5.7 below.

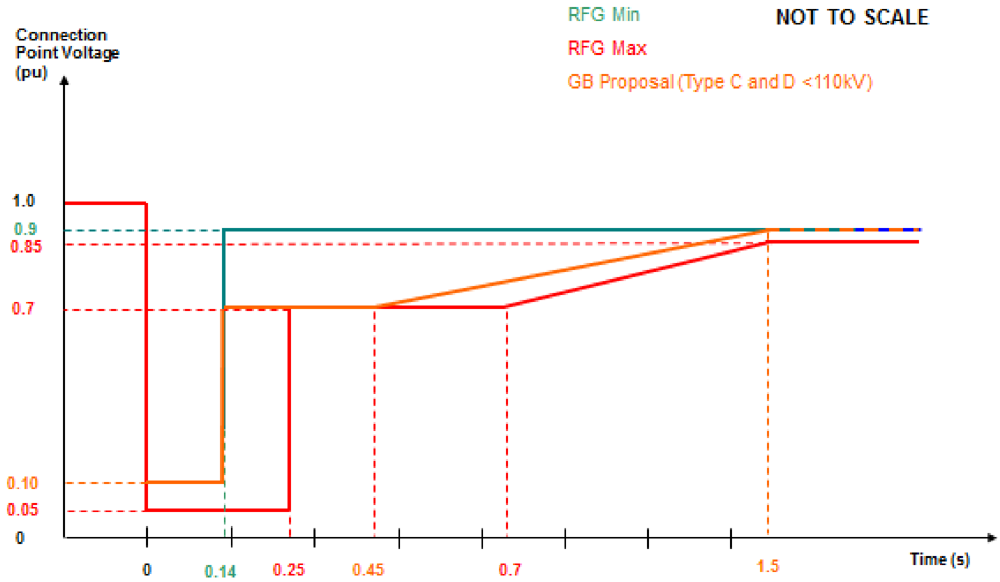


Figure 5.7 – Proposed voltage against time curve for Type, C and D Sychronous Power Generating Modules connected below 110kV.

Representing these values in tabular form results in the Table 5.4 below.

Voltage parameters [pu]		Time parameters [seconds]	
U_{ret}	0.10	t_{clear}	0.14
U_{clear}	0.7	t_{rec1}	0.14
U_{rec1}	0.7	t_{rec2}	0.45
U_{rec2}	0.9	t_{rec3}	1.5

Table 5.4 Proposed voltage against time paramters for Type, C and D Sychronous Power Generating Modules connected below 110kV.

3.7 Determination of RfG Voltage against time parameters as applicable to Type B Synchronous Power Generating Modules

The principles for deriving the voltage against time curve proposal for Type B Synchronous Power Generating Modules follows the same as methodology used to form the proposal for Type C and D Synchronous Power Generating Modules below 110kV.

The voltage against time parameters available to TSO's for Type B Synchronous Power Generating Modules are the same as those for Type C and D Synchronous Power Generating Modules connected below 110kV and as shown in Table 5.3 and Figure 5.6.

During the GC0048 Workgroup deliberations, AMPS members (i.e. representatives of Small Synchronous Generator manufacturers) identified that retained voltages dropping below 0.3pu would cause serious design issues and even then a Fault Ride Through compliant Type B Synchronous Power Generating Module would be exposed to significantly higher costs than a standard Generator (see Annex 4 Reference [2]). Even with these provisions in place, AMPS members have advised that there is currently no known technical or economical solution to achieving lower retained voltages unless techniques such as the connection of a Power Electronic Converter was connected to the Generator. This, in addition to having very high costs would also require Generators to satisfy the fault ride through Power Park Module requirements not the Synchronous Power Generating Module requirements.

Other than the retained voltage (Uret) being set at 0.3pu the other values would be set to the same values for Type C and D Synchronous Power Generating Modules as detailed above. Plotting this in graphical format between the RfG maximum and minimum values results in Figure 5.8.

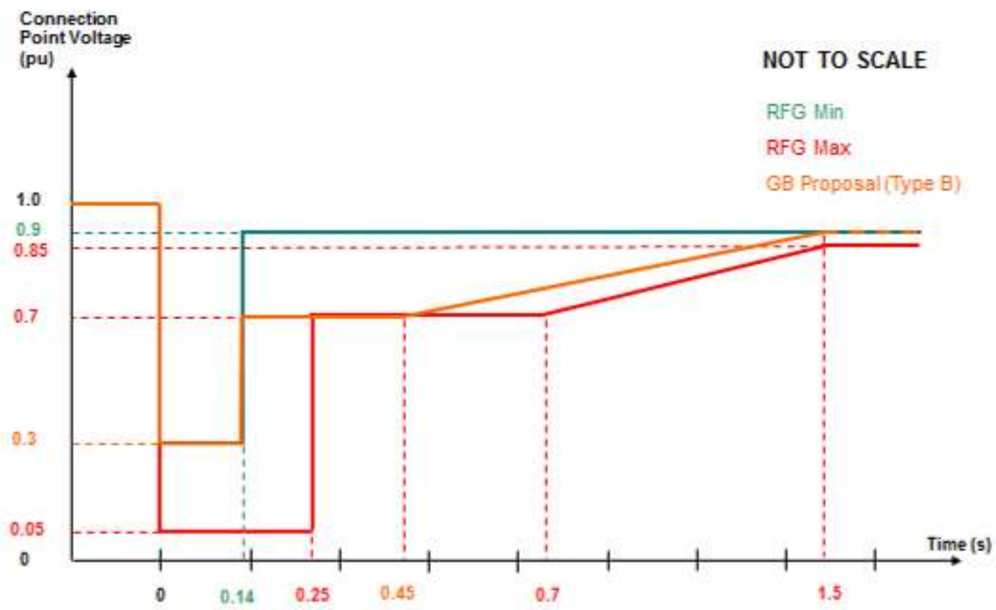


Figure 5.8 – Proposed voltage against time curve for Type, B Synchronous Power Generating Modules

Representing these values in tabular form results in the Table 5.5 below.

Voltage parameters [pu]		Time parameters [seconds]	
U_{ret}	0.3	t_{clear}	0.14
U_{clear}	0.7	t_{rec1}	0.14
U_{rec1}	0.7	t_{rec2}	0.45
U_{rec2}	0.9	t_{rec3}	1.5

Table 5.5 Proposed voltage against time paramters for Type B Sychronous Power Generating Modules connected below 110kV.

3.8 Determination of RfG Voltage against time parameters as applicable to Type D Power Park Modules connected at or above 110kV

The voltage against time curve for Type D Power Park Modules connected at 110kV or above follow the same principles as defined above although the parameters available to TSO's are fundamentally different thereby resulting in a different shaped curve. This is shown by Table 5.6 and Figure 5.9 below.

Voltage parameters [pu]		Time parameters [seconds]	
U_{ret}	0	t_{clear}	**0.14 – 0.15** (or 0.14 – 0.25 if system protection and secure operation so require)
U_{clear}	U_{ret}	t_{rec1}	t_{clear}
U_{rec1}	U_{clear}	t_{rec2}	t_{rec1}
U_{rec2}	0.85	t_{rec3}	1.5 – 3.0

Table 5.6 – Range of voltage against time parameters for Type D Power Park Modules connected at or above 110kV (Reproduced from Table 7.2 of RfG Article 16(3)(a)(i)

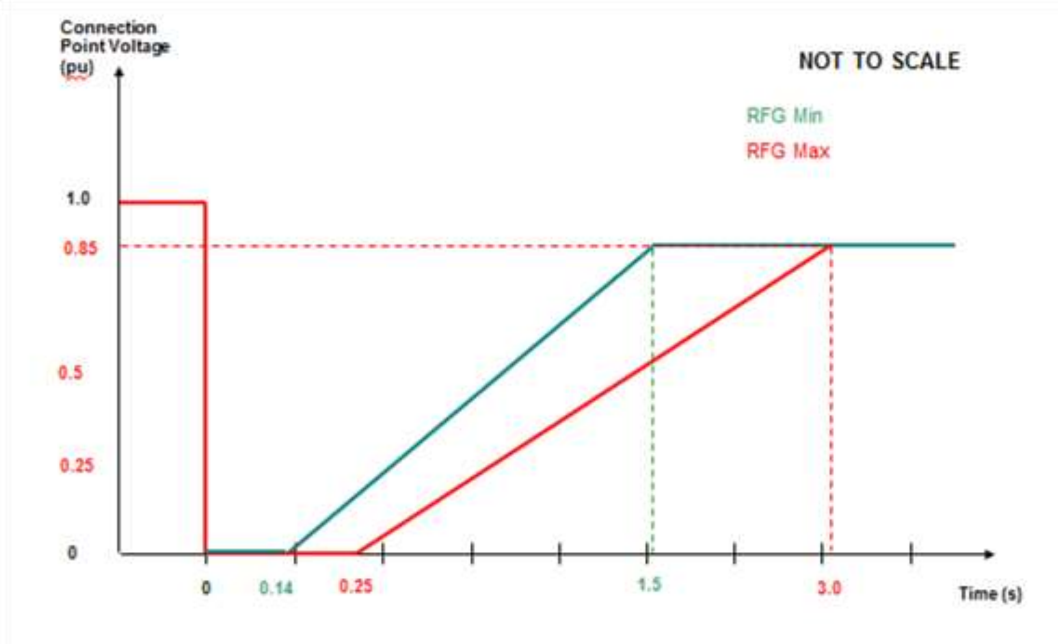


Figure 5.9 – Range of voltage against time parameters for Type D Power Park Modules connected at or above 110kV

Determination of the parameters for Type D Power Park Modules connected at or above 110kV follows a similar methodology to that of Synchronous Generators above although it is noted that the parameter ranges available to the TSO as specified in the RfG restrict the options available. Values for each point on the voltage against time curve have been set in the following way.

U_{ret}	Set to zero. This would equate to a solid three phase short circuit fault on the Transmission system which could be adjcent to a Power Generating Module.
t_{clear}	set to 140ms for protection operating times (as per synchronous power generating modules)
U, t	All other parameters (U_{clear}, U_{rec1}, t_{rec1} and t_{rec2}) are defined by RfG other than t_{rec3}.
U_{rec2}	Fixed at 0.85pu.
t_{clear}	Set to 2.2 seconds to line up with the SQSS – See Note 1

Note 1 - Under the SQSS an important value is a voltage of 0.9pu voltage at 2.2 seconds. It therefore seems appropriate to round trec3 up to 0.85pu at 2.2 seconds.

Whilst not so much of an issue for Transmission connected Power Park Modules, there is concern amongst the DNO community of the potentially slow voltage recovery of some wind farms connected to rural Distribution Network feeders. An example of this is shown in Figure 5.10 below in which a 132kV fault with a two transformer grid substation feeding generation connected at 33kV.

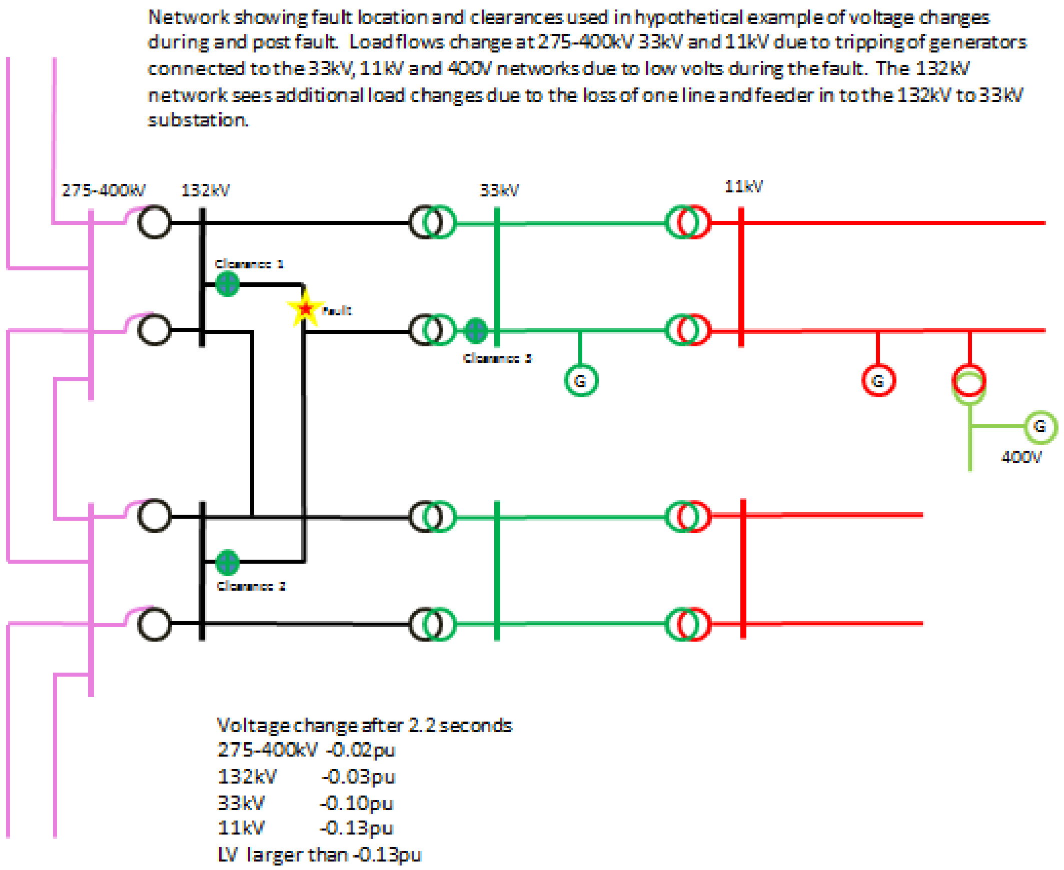


Figure 5.10

The 1st 132kV end clears at 100ms, the second 132kV end clears at 130ms and the 33kV protection operation clears at 440ms. Tap changer operation starts at 60 seconds and restores voltage to target at 110 seconds. The vertical line at 180 seconds to at least meet the statutory min voltage levels for the connection in question is typically 0.94 pu but without a defined end point.

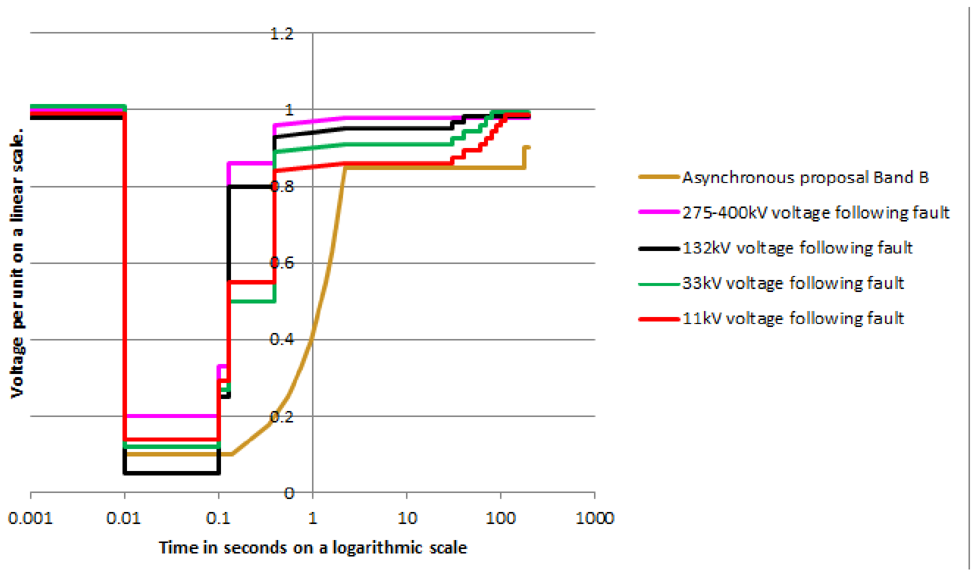


Figure 5.10 – Example of a 132kV fault with a two transformer grid substation feeding generation connected at 33kV

Taking this effect into account, it is important that Power Park Modules remain connected for the initial fault and then trips off as a result in the slow recovery of the voltage. This criterion is important in defining the period between 0.85pu voltage for 3 minutes and would apply to all Power Park Modules of Type B and above. As a result, the voltage against time curve for a Type D Power Park Module is shown in Figure 5.11 below with the corresponding list of parameters shown in Table 5.7.

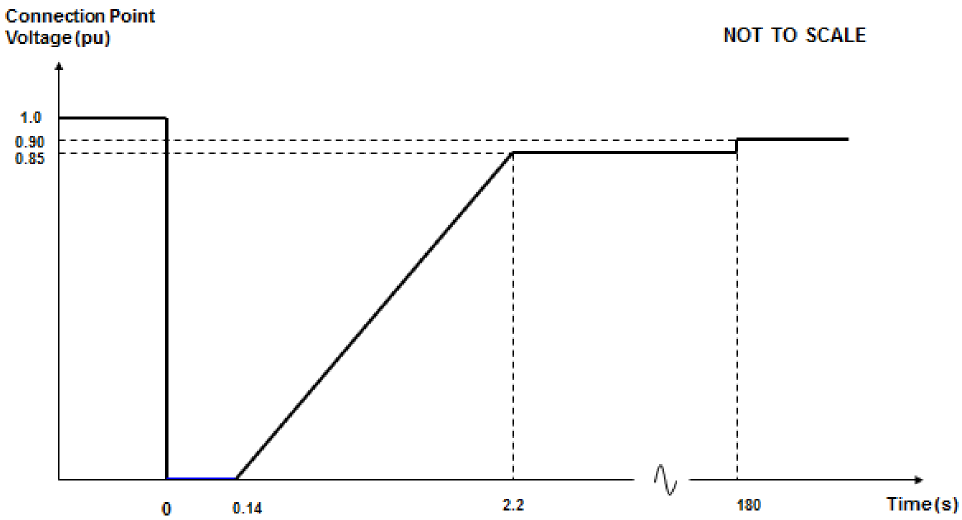


Figure 5.11 – Voltage against time curve for Type D Power Park Modules connected at or above 110kV

Voltage parameters [pu]		Time parameters [seconds]	
U_{ret}	0	t_{clear}	0.14
U_{clear}	0	t_{rec1}	0.14
U_{rec1}	0	t_{rec2}	0.14
U_{rec2}	0.85	t_{rec3}	2.2

Table 5.7 – Range of voltage against time parameters for Type D Power Park Modules connected at or above 110kV

3.9 Determination of RfG Voltage against time parameters as applicable to Type B, C and D Power Park Modules connected below 110kV

The voltage against time curve for Type B, C and D Power Park Modules connected below 110kV follows a similar methodology for determining the requirement as used for Type D Power Park Modules connected at or above 110kV. Under RfG Article 14 (3)(a)(iii) the requirements of Table 3.2 applies which is reproduced here in Table 5.8 below. This is shown graphically in Figure 5.12.

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

Table 5.8 - Range of voltage against time parameters for Type B, C and D Power Park Modules connected below 110kV (Reproduced from Table 3.2 of RfG Article 14(3)(a)(iii)

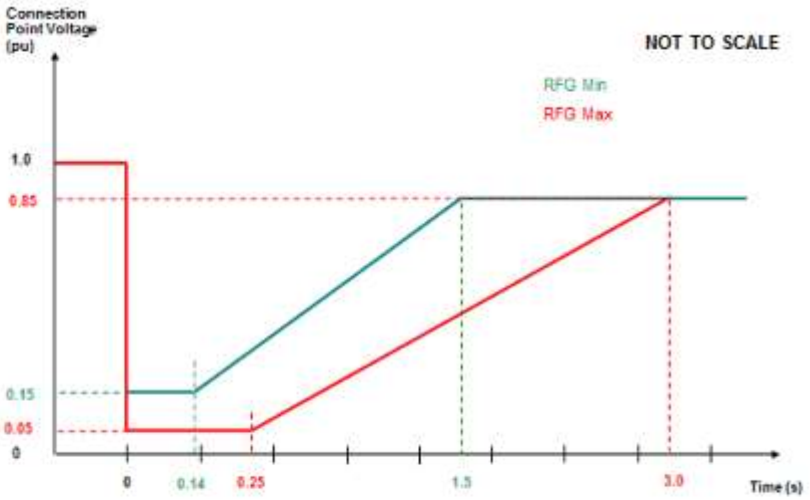


Figure 5.12 - Range of voltage against time parameters for Type B, C and D Power Park Modules connected below 110kV

3.10 Determination of the parameters for Type B, C and D Power Park Modules connected below 110kV follows a methodology for Type D Power Park Modules connected at or above 110kV.

t_{clear}	set at 0.14s – consistent with Transmission protection operating times and that required for Type D Power Park Modules connected at or above 110kV.
U_{ret}	set at 0.1pu. based on the fast fault current injection studies referred to in section 3 of this report. If the volume of fast fault current is not delivered as proposed in Section 3 of this report, consideration would have to be given to reducing U_{ret} to 0.05pu.
U_{rec2}	set at 0.85pu which is fixed by RfG. This simply marks the point on the voltage against time curve but would need to be interpolated to 0.9pu to align with the SQSS and the minimum steady state operating voltage as defined in CC.6.1.4 (RfG) Article 16(2)(a) – Tables 6.1 and 6.2).
t_{rec3}	Set to 0.85pu at 2.2 seconds.

Taking the above criteria into account results in the following voltage against time curve parameters which is shown in Table 5.9 and Figure 5.13.

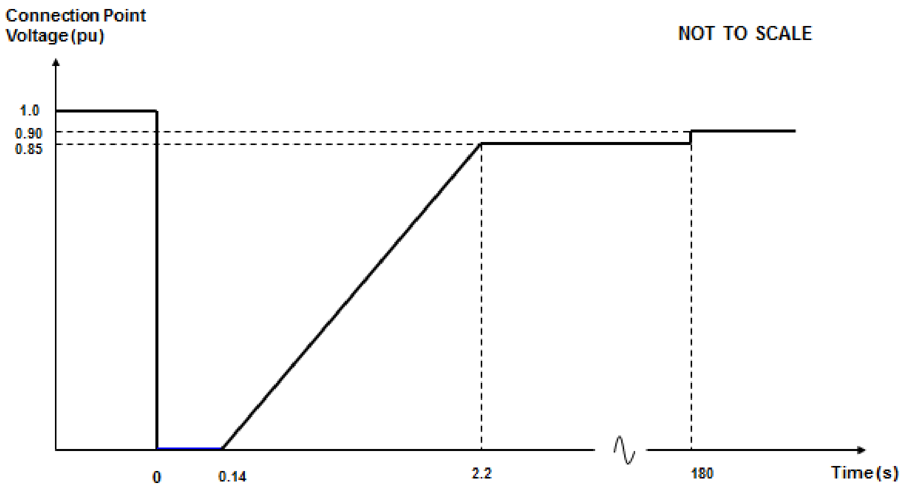


Figure 5.13 – GB Voltage against time curve for Type B, C and D Power Park Modules connected below 110kV

Voltage parameters [pu]		Time parameters [seconds]	
U_{ret}	0.1	t_{clear}	0.14
U_{clear}	0.1	t_{rec1}	0.14
U_{rec1}	0.1	t_{rec2}	0.14
U_{rec2}	0.85	t_{rec3}	2.2

Table 5.9 – GB Voltage against time paramters for Type B, C and D Power Park Modules connected below 110kV

For Type B, C and D Power Park Modules connected at any voltage, the value of U_{rec2} is set at 0.85pu at a value of t_{rec3} of 2.2 seconds. Based on RfG Tables 6.1 and 6.2 of Article 16, the steady state operating voltages are set at a lower value of 0.9pu for network voltages of 110kV and above.

3.11 **Fault Ride Through**

Fault Ride Through is considered as a transient event and allowing for tap changer operation, it is therefore considered that under worst case conditions the maximum permitted amount of time that a Generator is required to remain connected and stable would be where the connection point voltage would be at 0.85pu between 2.2 seconds and 180 seconds as described above. Even then, this would need to be considered on a case by case basis depending upon where the Generator is connected to the network. Unbalanced Faults

Article 14(3)(c) and Article 16(3)(c) of RfG define the Fault Ride Through capabilities in case of asymmetrical faults shall be specified by each TSO. There are potentially two separate options here these being either:-

- Adopt the same principles as RfG using a voltage against time curve. In this case the Power Generating Module would need to ride through any balanced or unbalanced voltage where the phase to phase or phase to earth voltage is above the heavy black line shown in each of the voltage against time curves above; or

- Retain the same approach as currently documented in the GB Grid Code – i.e. remain connected and stable for any unbalanced fault up to 140ms in duration.

This issue has been mentioned as part of the GC0048 Workgroup but not in any level of detail. An unbalanced fault will always be less onerous to the Generator than a balanced fault. It considered that adopting the same approach to that defined under RfG for unbalanced faults would provide greater clarity to developers and manufacturers in addition to ensuring consistency of requirements.

As such the proposed legal text covered in Annex 2 and 3 has been drafted on the basis of applying to balanced and unbalanced faults. A specific consultation question has also been raised on this issue to ensure Stakeholders are comfortable with this approach. It is also noted that in practice there is little difference between the RfG requirement and current GB practice – both requirements would necessitate the Power Generating Module to remain connected and stable for an unbalanced Transmission system fault for up to 140ms in duration.

3.12 **Active Power Recovery**

Article 17(3) – (Type B, C and D Synchronous Power Generating Modules) and Article 20(3) - (Type B, C and D Power Park Modules) define that the requirements for Active Power Recovery shall be specified by the relevant TSO.

The requirements for Power Park Modules are slightly more detailed than that for Synchronous Power Generating Modules but in general the requirements for Active Power Recovery would follow existing GB Grid Code practice which effectively states that following clearance of the fault, 90% of the Active Power before the occurrence of the fault shall be restored within 0.5 seconds.

For Power Park Modules the detailed requirements for Active Power recovery are also included in the requirements for fast fault current injection (Article 20(3)).

For Power Generating Modules of Types B – D, the requirement would be to retain the current GB requirement of 90% of Active Power within 0.5 seconds of fault clearance.

3.13 **Interaction between Voltage against time curves and G59 Protection [Distribution Users]**

The proposed voltage against time curves for Type B – D Power Generating Modules are detailed above. For those Power Generating Modules which are connected to the Distribution Network, stakeholders noted that there would be a conflict with the G59 under voltage Stage 2 protection which is currently set at 0.8pu for 500ms. Whilst this was marginal in the case of the voltage against time curve for Synchronous Power Generating Modules it was more severe in the case of Power Park Modules where even the minimum RfG voltage against time criteria would have been incompatible with the current G59 Stage 2 under-voltage protection settings.

These issues are shown in Figures 5.14(a) and 5.14(b).

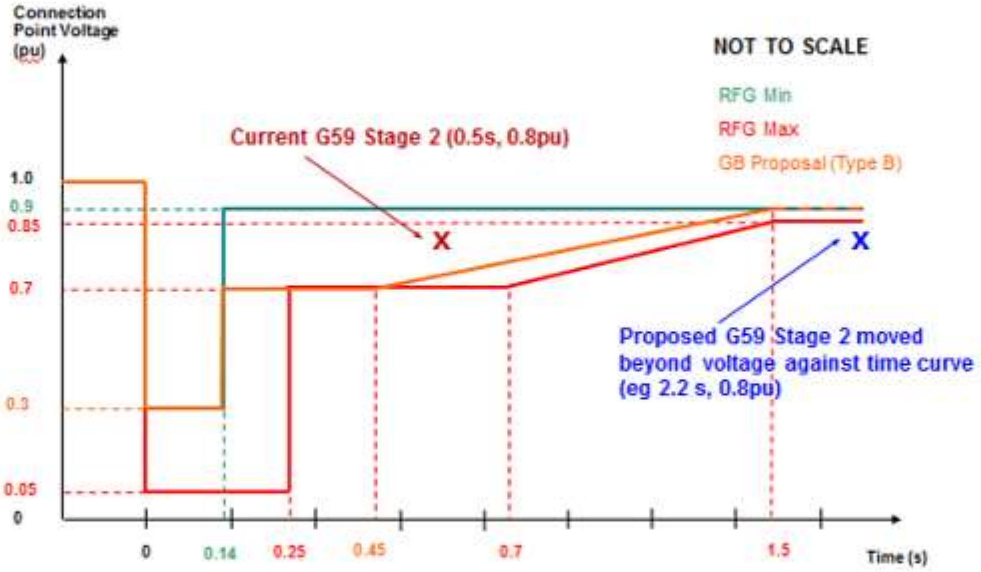


Figure 5.14(a) – GB Proposed Voltage Against Time Curve of a Type B Synchronous Power Generating Module showing the conflict with Stage 2 G59 Undervoltage Protection

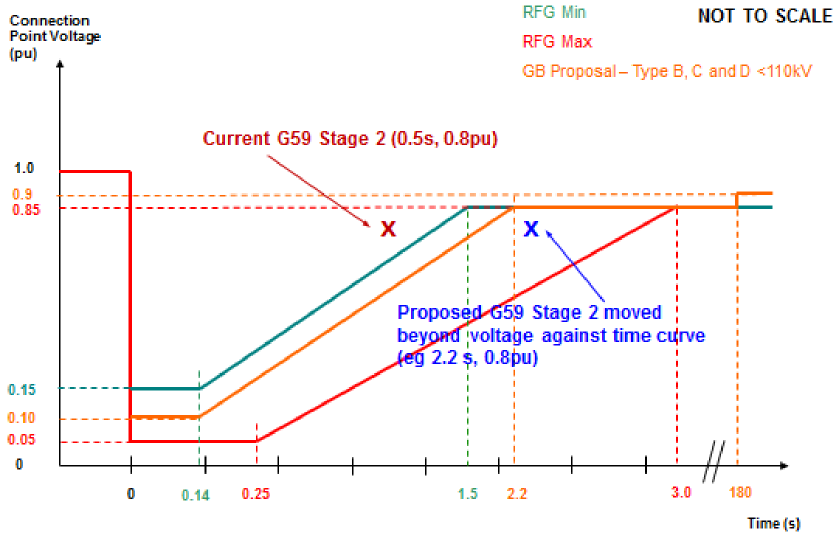


Figure 5.14(b) – GB Proposed Voltage Against Time Curve of a Type B, C or D Power Park Module connected below 110kV showing the conflict with Stage 2 G59 Undervoltage Protection

The Workgroup discussed this and The Proposer decided that the best policy for their original solution would be to move the G59 Stage 2 under-voltage protection to 0.8pu at 2.5s. This requirement would apply to all new connecting plant and would be equally applicable to Synchronous Power Generating Modules and Power Park Modules.

It is not believed that changing the G59 Stage 2 Undervoltage protection will cause a significant problem however it has been raised as a consultation question (see below). GC0079 has been investigating the issue associated with changing RoCoF protection settings for distribution connected generators and has undertaken a risk assessment of Distribution system protection requirements. The analysis has been performed for GC0079 (and GC0035) by the University of Strathclyde.

<u>Workgroup Consultation question</u>

1. Do you have any specific views about the proposal to modify the stage 2 undervoltage protection for distributed generation interface protection?

The University of Strathclyde were asked to comment on whether the proposed change to a single undervoltage protection would introduce any new risks. Their analysis pointed out that as the RfG only applies to new installations, it does not affect the risk profile for existing plant.

For new installations there is the opportunity to assess any and all risks as part of the connection process, and in addition as the risk assessment is undertaken assuming a 3s window, a trip on undervoltage at 2.5s is within the expected bounds of fault situations, thus presenting no additional risk.

For further information on the risk assessment techniques and assumptions see the GC0035 WG report, Annex 5, Reference [5].

3.14 Fault ride through Requirements during single phase auto-reclosures or Delayed Auto Reclosures (DAR)

RfG Article 15(4)(c) states that "Power Generating Modules shall be capable of remaining connected to the network during single phase or three phase auto-reclosures on meshed network lines, if applicable to the network to which they are connected. The details of that capability shall be subject to co-ordination and agreements on protection schemes and settings as referred to in point (b) of Article 14(5)".

In GB there is only place where a fast single phase auto reclose scheme is employed. In general, GB practice at a Transmission system level advocates the use of Delayed Auto Reclose Schemes (DAR). In the event of a line subject to a transient fault (e.g. lightning) the circuit will trip, the transient effects are allowed to decay away and the protection will automatically close the circuit breakers at the ends of the line.

An example of a situation which could occur is shown in Figure 5.15 below. In this example, the double circuit between substations A, B and C is subject to a transient fault which recloses by DAR operation 15 - 20 seconds later. Under this scenario the Generator connected to substation C would be permitted to trip, however the Generator connected to substation B is still connected to a healthy circuit and would be expected to remain connected and stable during the DAR event.

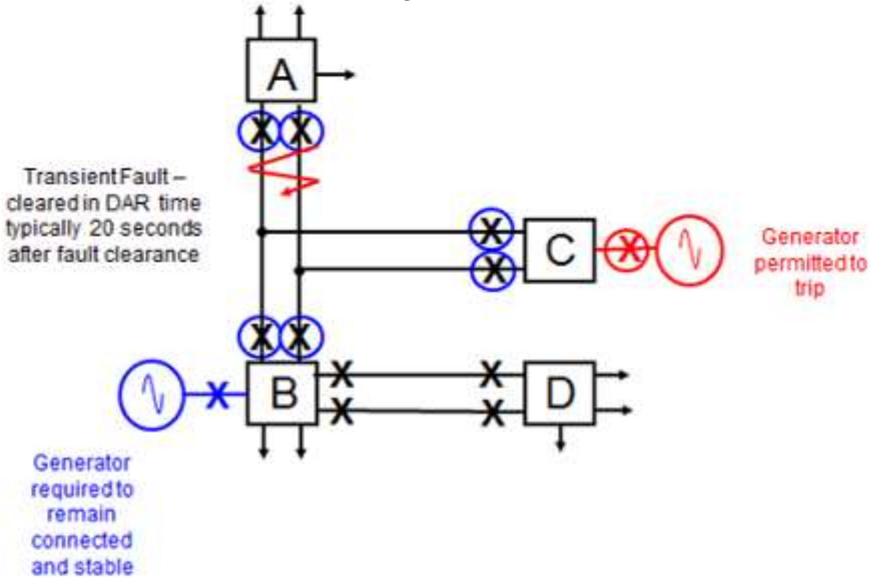


Figure 5.15 – Effect of DAR Operation and required Generator performance expected

As mentioned above, it is not standard practice for fast single phase auto re-closure schemes to be employed within GB, but if there were, the requirements applicable to them would need to be considered on a case by case basis.

In the case of Delayed Auto Reclose Schemes, the requirements of RfG Article 15(4)(c) would not apply where the Generator was connected to an unhealthy circuit (i.e. the Generator connected to substation C but would be applicable where the Generator connected to a healthy circuit (i.e. the Generator connected to Substation B. In GB there is no requirement to ride through auto-reclose sequences on Distribution systems.

3.15 Fault ride through requirements for Offshore Power Park Modules

RfG Article 26(2) states that the Fault Ride Through requirements laid down in point (a) of Article 14(3) and point (a) of Article 16(3) shall apply to AC Connected Offshore Power Park Modules.

GB is unique from the rest of Europe in that it has an Offshore Transmission regime. In summary this segregates the requirements from Offshore Transmission from Offshore Generation. Under the current GB Grid Code, Offshore Generators have the option of satisfying the Fault Ride Through requirements either at the Offshore Grid Entry Point or at the Interface Point (i.e. where the Offshore Transmission system connects to the Onshore Transmission system).

It is further complicated by the fact that the Offshore Grid Entry Point (i.e. the point where the Offshore Generator connects to the Offshore Transmission system) can vary as agreed between the Offshore Generator and Offshore Transmission Licensee. The default position is generally accepted as the LV side of the Offshore Platform but this can vary as agreed between the parties to be anywhere on the platform.

It should also be noted that the RfG requirements apply only to Offshore Power Park Modules, not Offshore Synchronous Power Generating Modules. The GB Grid Code does require Fault Ride Through to apply to all types of Offshore Generation. However, this is not relevant for newly connecting Offshore Synchronous Power Generating Modules.

The concern raised at the GC0048 Workgroup is that the current GB Grid Code enables Offshore Generators to satisfy the Fault Ride Through requirements either at the Offshore Grid Entry Point or the Interface Point. Unfortunately this option will no longer be available in a European Network Code environment however it may have limited practical impact.

For a Type D Offshore Power Park Module connected at the LV side of the Offshore Platform (which would typically have a connection voltage of 33kV) the Offshore Power Park Module would have to meet the voltage against time curve for a Type B, C or D Power Park Module connected below 110kV. The retained voltage at the connection point would be 10% which is slightly more onerous than the current GB requirement but this has been amended to take account of the fall in the overall volume of synchronous generation.

In terms of Fast Fault Current Injection, as mentioned above there would be no difference in the requirements to Offshore Power Park Modules as to their Onshore counterparts (i.e. an Offshore Power Park Module would have to meet either Option 1, Option 2 or Option 3 (as currently being consulted upon under the GC0100 Consultation) of the Fast Fault Current Injection requirements

3.16 Fast Fault Current Injection and Fault ride through Requirements for DC Connected Power Park Modules and Remote End HVDC Converters (Title III)

For DC Connected Power Park Modules, Article 38 of the HVDC Code stipulates that the requirements for DC Connected Power Park Modules shall be the same as those specified in the RfG Code.

There is an important distinction to be made here. The current RfG requirements define the parameters and ranges for Fast Fault Current Injection and Fault Ride Through. The actual detail of the settings and parameters are however defined by the TSO.

It is recognised that the configuration of DC Connected Power Park Modules continues to evolve as new technology is continually being introduced. In view of this and the need to satisfy the requirements of RfG, it is proposed that DC Connected Power Park Modules have to meet the same GB proposals for Fast Fault Current and Fault Ride Through as Type D AC-Connected Offshore Power Park Modules.

With regard to the priority of Active or Reactive Power for DC Connected Power Park Modules as defined in Article 40(3) of the HVDC Code, these requirements more or less replicate the requirements in RfG. As such it is proposed that the same requirements would apply as per the proposals for Type D Power Park Modules but allowing for an alternative as noted in the above paragraph.

With regard to remote end HVDC Converters, Article 46 of the HVDC Code states that the requirements of Articles 11 to 39 shall apply to remote end HVDC Converter Stations subject to the specific requirements provided for in Articles 47 to 50. With regard to Articles 47 to 50 there are no specific requirements in relation to Fast Fault Current Injection or Fault Ride Through.

It is therefore concluded to adopt a similar approach to that applied for DC Connected Power Park Modules – i.e. that the same proposals shall be adopted as per HVDC Connections under Title II but allowing for the specific clarification unless National Grid has agreed to an alternative requirement. It must be stressed however that any alternative agreed would still need to comply with the requirements of the HVDC Code ((Regulation EU) 2016/1447) but it does give the flexibility to change parameters and settings to reflect the technology.

4 Workgroup Discussions

4.1 Workgroup

The Workgroup convened four times to discuss the issue, detail the scope of the proposed defect, devise potential solutions and assess the proposal in terms of the Grid Code Applicable Objectives. The Workgroup will in due course conclude these tasks after this consultation (taking account of responses to this consultation).

The Proposer presented the defect that they had identified in the GC0100 proposal. The discussions and views of the Workgroup are outlined below.

4.2 Definitions

A complex area of this work has been the management of definitions between the defined terms used in the EU Network Codes and those used in the GB national network codes, such as Grid Code and Distribution Code.

Article 2 of RfG includes a number of definitions which relate to physical quantities for example, voltage and current. RfG does however define these terms for example

"Voltage" means the difference in electrical potential between two points measured as the root mean square of the positive sequence phase to phase voltages at fundamental frequency"

"Current" means the rate at which electric charge flows which is measured by the root mean square value of the positive sequence of the phase current at fundamental frequency."

These definitions do create a number of issues, largely because there are many different connotations of these physical quantities. For example, in a three phase system the voltage could be the instantaneous phase to neutral voltage, the instantaneous phase to phase voltage, the positive phase sequence RMS voltage, the transient over voltage to name but a few. The same issue arises with other physical quantities such as current. In these circumstances it was suggested by the Proposer that it was far better if the correct term as defined in IEC standards or equivalent are used.

This issue was discussed amongst the Workgroup on a number of occasions. In general the GB Codes do not define terms such as current or voltage as a result of the different set of circumstances under which they would apply. After advice was sought from the ENTSO-E code drafting team, some Workgroup Members set out that physical quantities or other standard engineering terms did not need to be re-defined to implement the EU Connection Codes, and that the current GB definitions could therefore be used. In the main this approach was accepted by the workgroup membership.

However, one Workgroup member was concerned that substituting GB definitions for those in the EU Network Codes may have unintended consequences, including that it could (i) amount to applying more stringent obligations[2] on 'new' connecting parties than required by the EU Network Codes and / or (ii) result in existing connected parties being obligated under the EU Network Codes without either (a) them having modified their facility to such an extent that their connection agreement required to be amended accordingly and / or (b) having not been the subject of a Cost Benefit Analysis undertaken in accordance with the EU Network Codes.

Some Workgroup members noted that whilst ENTSO-E's views on this topic were interesting, they had no vires to opine on this matter.

4.3 Interaction between Fast Fault Current Injection, Fault Ride Through and Banding

Article 20(2) of RfG defines the need for Relevant System Operators to define the requirements for Power Park Modules to supply Fast Fault Current Injection. The current GB Grid Code (CC.6.3.15) simply states that

[2] The background associated with 'more stringent' obligations is explored later in this section under 'Potential Alternatives (b) Removing More Stringent Requirements'.

Generating Units and Power Park Modules should supply maximum reactive current without exceeding the transient rating of the Generating Unit or Power Park Module.

Some Workgroup Members noted that alone does not provide sufficient detail to satisfy the requirements in RfG. Moreover, the changing nature of the generation has seen a trend towards more converter based plant connecting to the Distribution system which in turn has started to displace conventional synchronous generation connected to the Transmission system. This, the Proposer noted, has started to have a significant effect on the behaviour of the Transmission system.

Unlike Synchronous Generation which can instantaneously supply 5 – 7 times its rated current upon fault inception, converter based generation is limited to supplying just over its maximum rated current (i.e. 1 – 1.2pu rated current) and even then, the injected current will be delayed some tens of milliseconds following fault inception.

The implication of this, according to the Proposer, is that the voltage profile seen across the system during the fault would be lower than that compared to a system comprising solely of synchronous generation; this has important implications for Fault Ride Through (FRT).

Fault Ride Through is the ability of Generation to remain connected and stable to a healthy circuit when the Transmission system has been subject to a fault. The principle being that under the Security and Quality of Supply Standards (SQSS) the GB System Operator caters for a maximum infrequent infeed loss of up to 1800MW but does not cater for the loss of the total infeed source[3] connected to a healthy circuit. As such without Fault Ride Through there is the associated risk of cascade generation and / or interconnector tripping, frequency collapse and a black out situation.

Under RfG, Fault Ride Through is specified in respect of a voltage against time curve at the Connection Point, with the retained voltage (Uret) being a key parameter. For Type B, C and D Power Generating Modules connected below 110kV the value of Uret can be set at any value between 0.05pu – 0.3pu for Synchronous Power Generating Modules and 0.05 – 0.15pu for Power Park Modules.

The voltage profile observed across the system during a fault is a function of the reactive current injected; the greater the fault current injection, the higher the retained voltage.

It is known (as evidenced by Stakeholders during the GC0048 Workgroup – Annex 7) that synchronous generation driven by reciprocating engines (e.g. gas or diesel) which are typically up to a maximum of 5MW in size will be

[3]The SQSS caters for a maximum infrequent infeed loss of 1800MW which could be derived from Generation or an Interconnector. The SQSS does not however cater for a complete Power Station or Interconnector loss but rather a criteria on which the maximum volume of MW could be lost for a credible Transmission System fault.

unable to ride through voltage dips below 0.3pu. There is currently no known technical or economic solution to this problem other than installation of Power Electronic converters. Other forms of synchronous derived generation (e.g. gas turbines, steam turbines or hydro plant) are not believed to suffer from these problems. If power electronic converters were fitted it not only increases the cost disproportionally but secondly the under the definitions of the RfG European Code, it would be classified as a Power Park Module for which a different set of fault ride through and fast fault current requirements would apply.

One Workgroup Member pointed out that there would be no issue with electronic converters having to be re-classified and highlighted that the main point is for small generators to be able to ride through and not fall off the grid by increasing the size of the contingency. The Workgroup Member further noted the need for the increase in costs to be compared alongside wider costs and benefits imposed by this type of generation.

Analysis conducted by the Proposer as part of this work has demonstrated that a value of Uret of 0.1pu would be required for all Power Park Models above 1MW and all Synchronous Generators above 10MW. If the volumes of Fast Fault Current Injection were not forthcoming, then consideration would need to be given to reducing the value of the retained voltage even further typically to 0.05 pu.

Under RfG, it is not possible to split bands for the four generation Types (e.g. if Band B was set at 1- 50MW it is not possible to have one set of Fault ride through parameters between 1 – 10MW and another parameter set between 10 – 50MW).

Following the GC0048 consultation on banding in 2016, no significant evidence was presented from the generator community other that the material cost threshold of £10,000 for compliance would be incurred as a result of lowering the GB banding level from the maximum permitted in the RfG; although some Workgroup members noted that the banding levels set in the RfG were, subsequently, used in some of the other EU Network Codes and associated documents (such as, for example, the System Operation Guideline and the Generation Load Data Provision Methodology).

Other costs and benefits associated with these proposals are described later in this report. However the volume of Fast Fault Current Injection is contingent on the value of retained voltage – a key parameter for Fault Ride Through which in turn affects the banding level.

The current Distribution Code does not specify a Fault Ride Through requirement for Small Embedded Power Stations. The Proposer noted that whilst Fault Ride Through requirements have been applied to Medium and Large Power Stations; this had been achieved through Grid Code requirements. The requirements that will apply, according to the RfG, to Type B and above generation will result in mandatory Fault Ride Through capabilities needing to be specifically written into the Distribution Code and associated Engineering Recommendations.

4.4 **Setting the RfG Fast Fault Current Injection Parameters in GB**

As has been described in section 3.2, Fast Fault Current Injection is currently only loosely defined in section CC.6.3.15 the GB Grid Code which simply states that the Generating Unit or Power Park Module shall inject maximum fault current without exceeding the transient rating of the Generating Unit or Power Park Module.

RfG is silent on the fast fault current injection requirements for Synchronous Power Generating Modules and as a result no requirement is specified here as it is an inherent capability for these kinds of Power-Generating Facilities to inject high fault currents when subject to a disturbance.

So far as Power Park Modules are concerned, RfG Article 20(2)(b) defines the requirements for Fast Fault Current Injection. These requirements are far more specific than the current GB Grid Code requirements.

It is firstly important to state that under RfG, the System Operator in co-ordination with the relevant TSO shall have the right to specify that a Power Park Module must be capable of providing Fast Fault Current at the connection point in the case of symmetrical (3-phase) faults and asymmetrical faults (1-phase or 2 phase).

System analysis has demonstrated the need for the injection of fast fault current. There are a number of options for this, including different control strategies, operational running regime, market solutions or the use of additional reactive compensation equipment such as Synchronous Compensators. In addition, the current GB Grid Code also defines in loose terms the need for Generating Units and Power Park Modules to inject reactive current. As there is a defined system need for reactive current injection then going forward any requirement for reactive current injection by new connecting Type B generation[4] would need to comply with the requirements of RfG (whilst existing generation would continue to be subject to the current Grid Code requirements).

To develop the requirements for fast fault current injection, the Proposer ran a number of detailed studies. These largely concentrated on the modelling and behaviour of the converter performance. As part of this study, the converter was modelled as a i) a negative demand (ie zero reactive current injection), ii) a standard Phase Locked Loop (PLL) Converter (ie conventional converter model iii) A Phase Locked Loop Converter model where the maximum ceiling current and rise time were varied and iv) the converter was modelled to have the same characteristics

[4] Namely that generation which falls within the scope of the RfG Network Code.

as a synchronous machine. This latter controller is referred to as the virtual synchronous machine or VSM.

In summary conventional PLL converters are slow to inject reactive current and this in turn will affect the retained voltage at the connection point which is a key criteria for fault ride through.

The Virtual Synchronous Machine model does however inject reactive current into the system immediately upon fault inception and on fault clearance immediately reduces reactive current injection and therefore gave significantly better results than the other models. This results in faster support for the network voltage during the fault but also avoids temporary overvoltage following fault clearance. However it is very much a solution to which there have been no real full scale commercial trials or application on public Grid Systems though there have been applications for its use in the Marine industry. It is also recognised that mandating such requirements by May 2018 is an unreasonable requirement. That said a lower requirement based on the current available capabilities of converter based technology is possible and as part of this work, three options are presented which are described later in this report. Full details of this study work are detailed in Annex 5 which concentrated on the South West but additional studies have shown that the conclusions of this study are equally applicable to other parts of the country.

An important part of this study is that to inject no reactive current is not an option and some degree of fast fault current injection will be necessary which will have to be specified as part of compliance with the RfG Code (Article 20).

In terms of overall performance, the higher the injected reactive current and the faster it can be supplied, the greater the retained voltage which is important in retaining an adequate voltage profile across the system, particularly for Fault Ride Through. It was notable that any delay in delivering fault current did have a notable effect on the retained voltage.

So far as the conclusions of the study (which can be located in Annex 5) are concerned, the virtual synchronous machine converter controller, in the view of the Proposer, provided very good performance. It is fully accepted that this is new and an evolving technology and requires further assessment. In addition to the benefits in contributing to fast fault current it also has the following features:-

- Contribution to synchronising torque
- Contribution to System inertia and Rate of Change of System Frequency (RoCoF)
- Compatible with Synchronous machines
- Reduced interaction and high frequency instability risks
- Can be modelled in Route Mean Square (RMS) studies
- It can be easily integrated into existing Grid Systems and enables greater market share for converter derived generator technologies

- It does however have the disadvantage of requiring Storage / overload capability and they suffer from the classical instability issues associated with conventional synchronous generators.

Most of the listed features can be obtained from the current generation of VSC converter controls, specifically; contribution to System Inertia, and RoCoF, compatible with synchronous machines, is not materially different interms of interaction and high frequency instability, RMS modelling is not valid unless fully verified with EMT models and this applies both to existing VSC controls as well as VSM, VSC can be easily integrated.

It is acknowledged that whilst the Virtual Synchronous Machine did offer significant advantages compared to the other converter controller this needs to be put in the wider context of the System as a whole and what other solutions such as synchronous compensators or market based solutions could be used. That said, RfG is mandating a converter performance requirement which would be applicable to all Type B Power Park Modules and above. If a lower specification were adopted then there would still be a requirement for a minimum converter performance requirement but with some alternatives such as the use of Synchronous Compensation equipment installed around strategic parts of the system. Whilst installing synchronous compensators is a conventional, mature technology which is used in many parts of the world and other European countries (e.g. Norway) are considering this approach. The cost and strategic location of these synchronous compensators would need to be fully understood.

It is probably worthy of note that whilst VSM technology is considered to be very much emerging, other developments around the world investigating this type of technology. ENTSO-E commissioned a one year study in the second half of last year (2016) to look at the effect of Grid Forming Converters which would include VSM type technology. This alone will fall outside the timescales of Rfg implementation. In addition, CIGRE are also looking at these types of concepts.

A Workgroup member engaged with a number of suppliers, developers and well renowned consultants in this particular area. A consensus was provided that Voltage Source PPM and HVDC have no inherent overload capability. Therefore any implementation of overload will lead to two key impacts for developers

Impact 1: Overload “headroom” will need to be created. This leads to a non-economically efficient technical solution to the developers and

Impact 2: UK specific products - The nett impact for developers would be increased cost and additional technology risk as new requirements create unique or unproven technologies.

In summary, the Proposer stated that the conclusions and subsequent proposals arising out of this study work were as follows:-

- The current GB Grid Code requirement for Fast Fault Current Injection under CC.6.3.15 (inject maximum reactive current without exceeding the transient rating of the Generating Unit or Power Park Module) is not tenable in the longer term as it does not address the delays in injecting fault current nor the loss in synchronising torque which results in low values of retained voltage. To this end, a significant generation loss in the future with a low background of synchronous generation is more likely to result in a blackout situation rather than simply operation of low frequency demand disconnection relays.
- Fast Fault Current Injection is a requirement, and proposals will need to be put in place to ensure consistency with RfG.
- VSM type technology offers a possible solution in the longer term but this would need to be assessed against other alternatives such as other control schemes or synchronous compensation options but the total cost of all these solutions requires assessment. .

With the GB Grid Code to be updated by May 2018 to ensure consistency with RfG, it is unreasonable to expect newly connecting Type B and above Generators to satisfy any form of VSM type requirement by this time. Three options are therefore proposed for new Power Park Modules and HVDC equipment

Option 1 would effectively require new Type B and above Power Park Modules and HVDC Plant to act as a voltage source behind a constant reactance (i.e. VSM type technology). The Grid Code legal text (Annex 2 of this report) would simply define a functional performance requirement.

Option 2 requires a minimum volume of reactive current injection as shown in Figure 4.4(a) and (b). Blocking is permitted on fault clearance to prevent the risk of transient overvoltages). This option would apply to all New Type B and above Power Park Modules which had not signed their contract for major plant items by 17 May 2018 or HVDC Owners who had not signed their contract for major plant items by September 2018.

Option 3 is a duplicate of Option 2 above but the maximum ceiling current would be limited to 1.0pu as shown in Figure 4.5(a) and 4.5(b). This option would apply to all New Type B and above Power Park Modules which had not signed their contract for major plant items by 17 May 2018 or HVDC Owners who had not signed their contract for major plant items by September 2018.

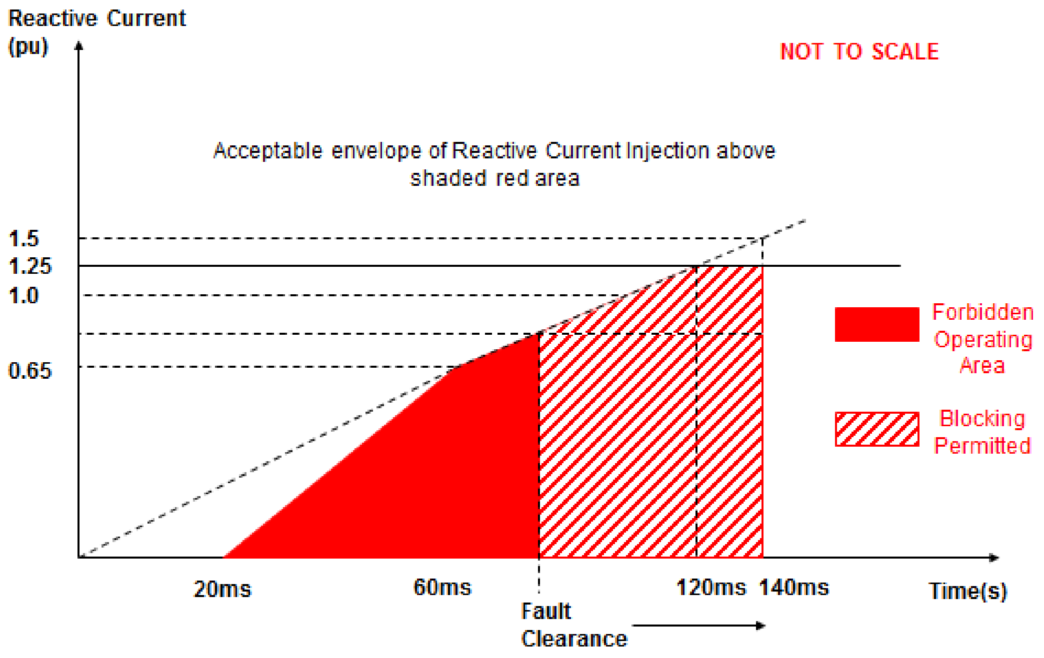


Figure 4.4 (a) Effect of Fast Fault Current Injection Option 2 on clearance time

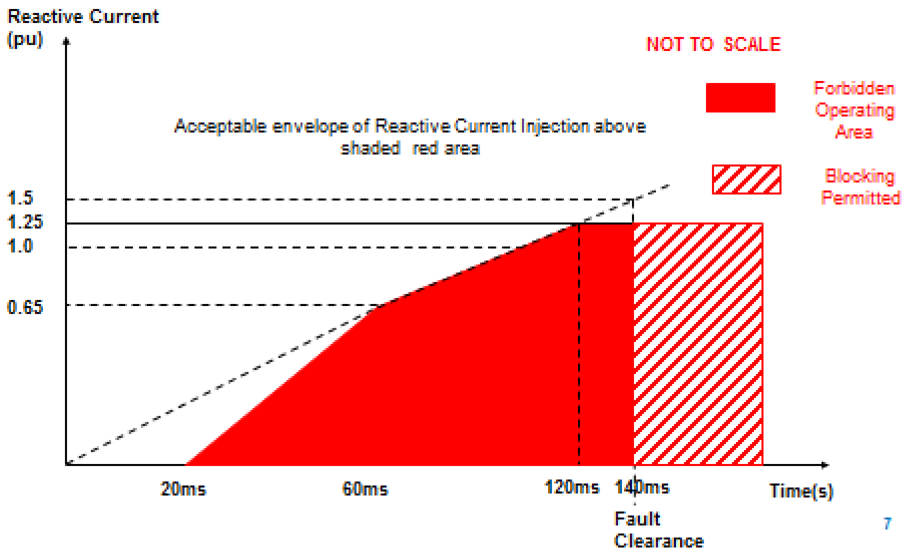


Figure 4.4 (b) Effect of Blocking Option 2 on slow fault clearance time up to a maximum of 140ms

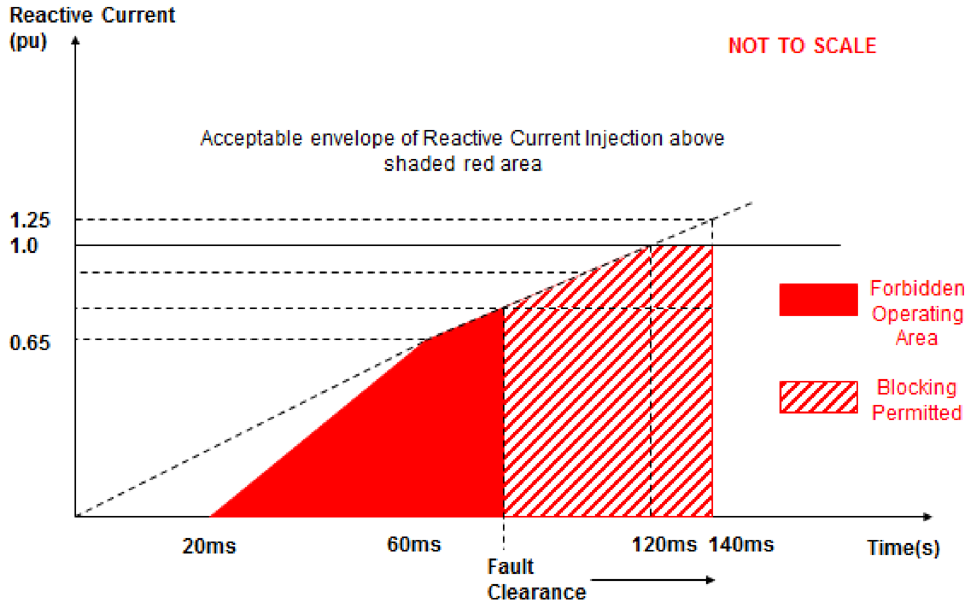


Figure 4.5 (a) Effect of Blocking Option 3 on a fast fault clearance time

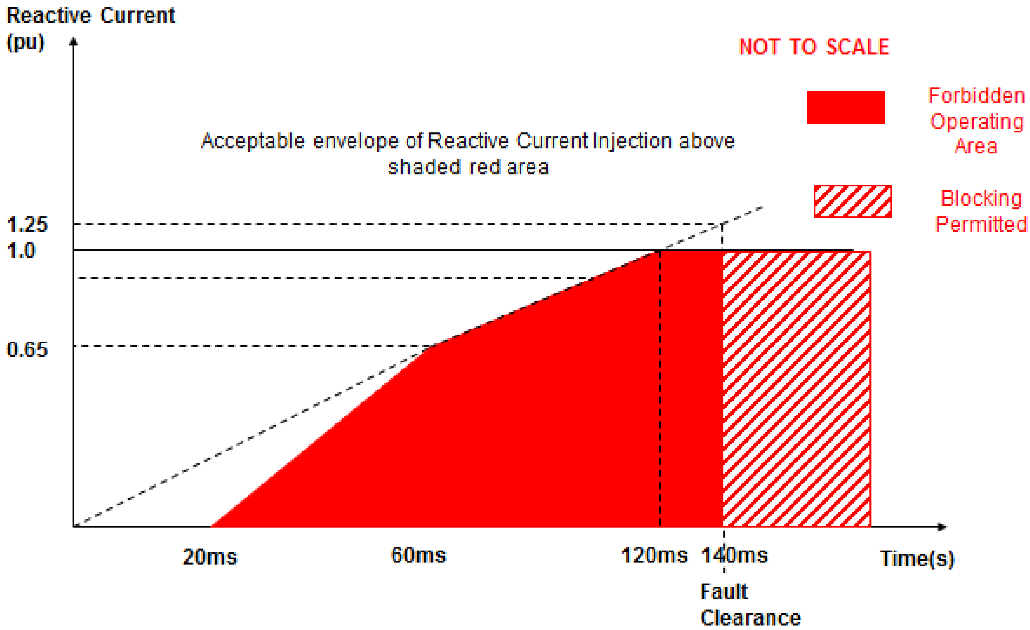


Figure 4.5 (b) Effect of Blocking Option 3 on slow fault clearance time up to a maximum of 140ms

The workgroup discussed all three options and corresponding legal text has also been developed as shown Annex 2 & 4. As a result of these discussions, a number of important points were noted. These being

VSM technology (option 1) does have the potential to provide a significant number of system benefits.
VSM technology is unproven and requires longer development timescales in addition to some form of international benchmarking.
Other alternatives such as the use of Synchronous Compensation equipment needs to be considered in addition to the overall System costs.

From the System Operators perspective, there is the immediate short term need to implement the EU Connection codes which include the requirements for Fast Fault Current Injection. In the longer term, there is the need to ensure the robustness and integrity of the System in a reasonable, proportionate and efficient manner.

This consultation seeks views on the Fast Fault Current Injection for new Type B Power Park Modules and above and HVDC Equipment. Whilst Option 1 (VSM) does offer a long term solution, if either Option 2 or Option 3 are ultimately selected, then an expert working group would need to be established in parallel with the EU implementation work to look in more detail at the future options, costs and market based solutions for VSM type equipment or otherwise with a conclusion being reached before 2021 as after this time the information available to National Grid through the Future Energy Scenario's has shown a rapidly falling decline in the volume of synchronous generation connected to the System.

Please note that the Proposer of this modification will finalise its solution following this consultation and assessment of the responses received outlining option preference.

Workgroup Consultation questions

The GC0100 Workgroup is seeking answers to the following questions set out on the response proforma. The full set of questions can be found in Section 8

1. What are your views on options 1, 2 and 3 as set out in paragraph 4.4 for Fast Fault Current Injection and which option (if any) would you prefer.
2. Do you have any alternative fast fault current injection solutions noting that the requirement applies to the Converter not the wider Power System
3. In considering the three Fast Fault Current Injection options 1, 2 and 3 in paragraph 3.3 do you have any comments in relation to technology readiness, cost implications, and can they be implemented date within the context of product development timescales
4. Do you have any evidence to support your views?
5. Do you have any views on the specific costs related to the additional requirements?

4.5 Application of Fast Fault Current Injection requirements to Offshore Power Park Modules

As stated in RfG Article 25(4) "The voltage stability requirements specified respectively in points (b) and (c) of Article 20(2) as well as in Article 21(3) shall apply to any AC connected Offshore Power Park Module."

In terms of Fast Fault Current Injection, there would be no difference in the requirements to Offshore Power Park Modules as to their Onshore counterparts (i.e. an Offshore Power Park Module would have to meet either Option 1 or Option 2 of the fast fault current injection requirements).

4.6 **HVDC Fast fault Current Injection and Fault ride through**

Background

The HVDC Code deals with three types of equipment – HVDC Systems, DC Connected Power Park Modules and Remote End HVDC Converters. HVDC Systems covers Interconnector type installations between say one Synchronous Area and another be they current source or voltage source. All these configurations are covered under Title II of the HVDC Code.

On the other hand, Title III of the HVDC Code covers DC Connected Power Park Modules and Remote End HVDC Converters. These representations are shown in Figure 7.1(a) and (b).

Figure 7.1 (a) – Illustration of a HVDC Connection caught under the requirements of Title II of the HVDC Code.

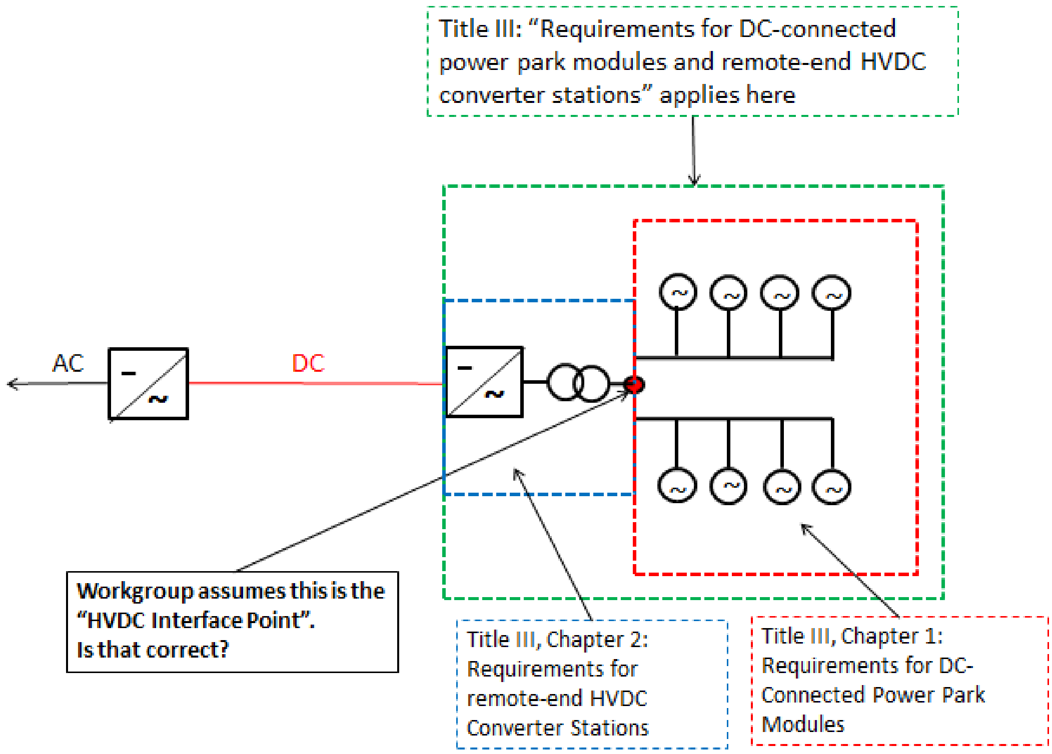


Figure 7.1(b) – Illustration of DC Connected Power Park Modules and Remote End HVDC Converters caught under the requirements of Title III of the HVDC Code in addition to the appropriate definitions used under the HVDC Code.

4.7 **HVDC - Approach to Fault ride through and Fast Fault Current Injection**

In developing the Fault Ride Through and Fast Fault Current Injection requirements for HVDC Connections, DC Connected Power Park Modules and Remote End HVDC Converters the general approach adopted is to use the same requirements proposed for Type D Power Park Modules under the RfG Code, unless there is good reason not to do so. However, some Workgroup members were concerned that this would apply a more stringent[5] requirement on newly connecting HVDC Connections, DC Connected Power Park Modules and Remote End HVDC Converters.

[5] The background associated with 'more stringent' obligations is explored later in this section under 'Potential Alternatives (b) Removing More Stringent Requirements'.

4.8 **HVDC - Fast Fault Current Injection and Fault ride through Requirements for HVDC Connections (Title II)**

The requirements for Short Circuit contribution during faults, Fault Ride Through and Post Fault Active Power recovery for HVDC Connections are detailed in Articles 19, 25 and 26 of Title II and Annex V of the HVDC Code.

The requirements for short circuit contribution during faults is defined in Article 19 of the HVDC Code. In summary, the HVDC requirements for short circuit contribution during faults are very similar to the requirements for fast fault current injection for Power Park Modules required under RfG. As with the RfG Code, the requirement for a Fast Fault Current Injection capability needs to be specified by the relevant System Operator.

As highlighted earlier in this report, system studies have demonstrated the importance of injecting sufficient volumes of fault current into the system, not least to ensure an adequate voltaqe profile across the system which is important for the determination of the Fault Ride Through parameters.

To this end and in view of the similar requirements with RfG it is therefore suggested that the same proposals for Fast Fault Current Injection under RfG are also applied to HVDC Connections caught under Title II of the HVDC Code. In summary, this proposal provides for two options, these being (i) – Option 1 the Converter behaves as a voltage source behind a constant impedance or (ii) the requirement to supply a minimum reactive current injection above a defined minimum criteria. Option 2 would be time limited with option 1 applying for main equipment contractual date commencing on or after 1 January 2021.

The requirements for Fault Ride Through for HVDC Connections caught under Title II of the HVDC Code are slightly different to those under RfG. In general, the principles are very similar to those of the RfG Code in respect of the need to withstand a voltage depression at the connection point. The difference however is that the voltage against time curve and parameters of that voltage against time curve are slightly different. Figure 7.2 below is a reproduction of the Voltage against time profile of an HVDC Converter Station which has been taken from Annex V of the HVDC Code.

Voltage-against-time-profile referred to in Article 25

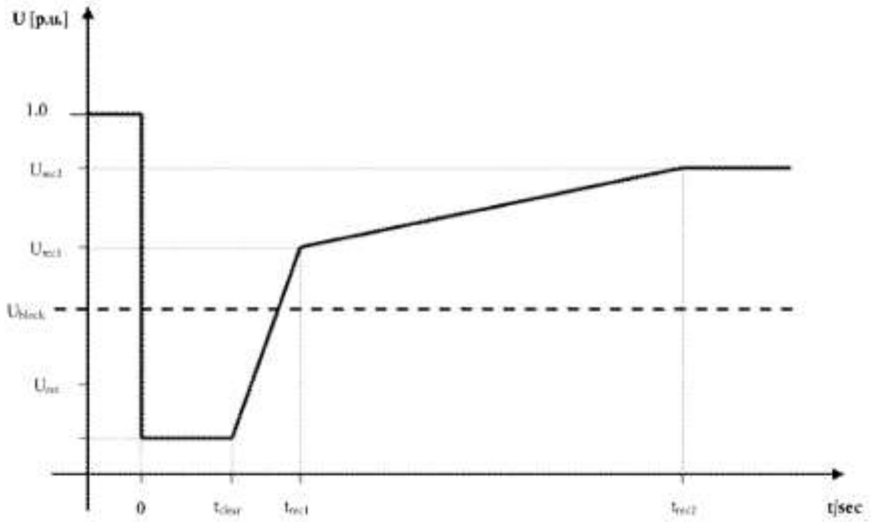


Figure 6: Fault-ride-through profile of an HVDC converter station. The diagram represents the lower limit of a voltage-against-time profile at the connection point, expressed by the ratio of its actual value and its reference 1 pu value in per unit before, during and after a fault. U_{ret} is the retained voltage at the connection point during a fault, t_{clear} is the instant when the fault has been cleared. U_{rec1} and t_{rec1} specify a point of lower limits of voltage recovery following fault clearance. U_{block} is the blocking voltage at the connection point. The time values referred to are measured from t_{fault}.

Figure 7.2 – Extract from Figure 6 of Annex V of the HVDC Code – Voltage against time curve

The range of parameters available to the TSO for the determination of this curve is as shown in Table 7.1 below.

Voltage Parameters (pu)		**Time Parameters (Seconds)**	
U_{ret}	0.00 – 0.30	t_{clear}	0.14 – 0.25
U_{rec1}	0.25 – 0.85	t_{rec1}	1.5 – 2.5
U_{rec2}	0.85 – 0.90	t_{rec2}	t_{rec1} – 10.0

Table 7.1 – Range of HVDC Fault ride through Parameters available to be selected by the TSO

The justification for the voltage against time curve proposed for HVDC Converter Stations follows a similar approach to RfG with the proposed values and the reasons given in Table 7.2 below.

U_{ret}	Set to zero. This would equate to a solid three phase short circuit fault on the Transmission system which could be adjcent to an HVDC Converter
t_{clear}	Set to 140ms for protection operating times (as per the RfG proposals)
U_{rec1}	Set to 0.85 to ensure consistency with RfG proposals for Type D Power Park Modules
t_{rec1}	Set to 2.2 seconds to ensure consistency with with RfG proposals for Type D Power Park Modules
U_{rec2}	Set to 0.85 to ensure consistency with RfG proposals for Type D Power Park Modules
t_{rec2}	Set to 10 seconds to ensure consistency with RfG proposals for Type D Power Park Modules
U_{block}	Not defined – see note below.

Table 7.2 – Proposed voltage against time parameters for HVDC Converter Stations under Title II of the HVDC Code.

Under the HVDC Code, TSO's are allowed to specify a Blocking Voltage (U_{block}) which is the point at which the HVDC Converter will not supply any real or reactive power. As mentioned earlier in the report, the supply of fast fault current under Fault Ride Through conditions is vital to maintain an adequate voltage profile across the system. With no reactive current injected, this would undermine the desired system characteristics. Under the proposals for Fast Fault Current Injection, Option 2 or Option 3 does permit blocking but this is only upon fault clearance and is necessary to prevent the risk of overvoltage transients.

Representing Table 7.2 graphically results in Figure 7.3 below.

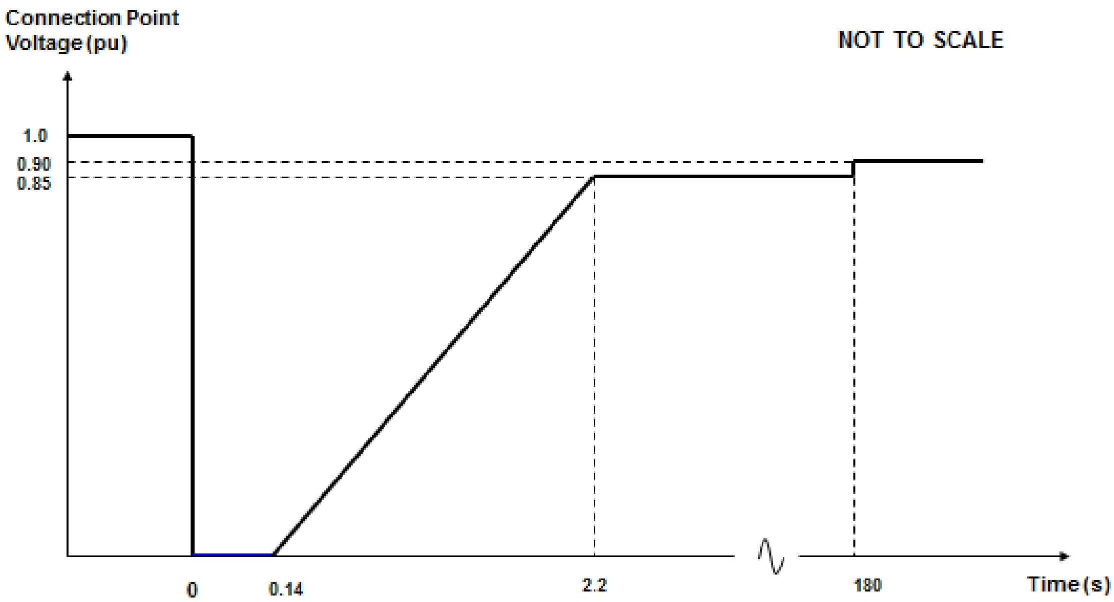


Figure 7.3 – Proposed Voltage against time curve for Title II HVDC Converters

In terms of Active Power Recovery as defined under Article 26 of the HVDC Code, 90% of the Active Power should be restored within 500ms of fault clearance. These requirements would be consistent with the RfG requirements.

Consultation questions – Fault Ride Through

The GC0100 Workgroup is seeking answers to the following questions set out on the response proforma. The full set of questions can be found in Section 8

1. Do you support the fault ride through voltage against time curves If not please state why you disagree, what alternative you would recommend and your justification for any alternative?

2. Do you have any specific views about the proposal to modify the stage 2 under voltage protection for distributed generation interface protection?

4.9 Set the four RfG Generation Type (A-D) MW banding levels for GB

What does RfG banding do?

ENTSO-E provided the following guidance on how the four banding levels evolve power generating module technical capabilities to support the system:

	Type A	Type B	Type C	Type D
Connection Voltage:	<110kV	<110kV	<110kV	≥110kV
	MW capacity range for Power Generating Modules:			
Continental Europe	800W-1 MW	1 MW-50MW	50 MW-75 MW	75 MW+
Great Britain	800W-1 MW	1 MW-50MW	50 MW-75 MW	75 MW+
Nordic	800W-1.5 MW	1.5 MW-10MW	10 MW-30 MW	30 MW+
Ireland and Northern Ireland	800W-0.1 MW	0.1 MW-5MW	5 MW-10 MW	10 MW+
Baltic	800W-0.5 MW	0.5 MW-10MW	10 MW-15 MW	15 MW+

Adapted from RfG Article 5, Clause D, Table 1

It is worth noting that previous ENTSOE versions of the RfG text had maximum GB synchronous area banding levels at a lower level, closer aligning England and Wales with the historic Scottish TSO (SHE Transmission) designation of 'Large' Power Stations:

January 2014 RfG draft GB Levels:

	Type A	Type B	Type C	Type D
Connection Voltage	<110kV	<110kV	<110kV	≥110kV
MW range for Power Generating Modules	0.8KW-1MW	1MW-10MW	10-30MW	30MW+

Process for TSO's setting their banding level

RfG requires national TSOs to set their banding levels and ratify them via an industry consultation and National Regulatory Authority approval. This is required for implementation, but is also the same process for any subsequent review, as allowed at an interval of no less than three years. Subsequent iterations of the banding levels can never exceed the levels drafted into the RfG itself, which therefore provides a ceiling.

Assessing appropriate levels for GB level

Particular Workgroup focus was given to the MW level for the Type B-C boundary, the point at which the technical requirements evolve from a manufacturer standard and become associated with much more active real-time response capabilities (e.g. frequency control).

GB generation is currently grouped by Power Station net capacity for determining compliance obligations (Large/Medium/Small designations), whereas RfG refers to 'power-generating module' Type (by sizing bands) for determining significance. Understanding the nature of connections to GB synchronous area is important when considering RfG banding levels.

For example, will existing patterns of installed capacities continue when RfG applies, and are existing levels of response still fit for purpose?

A 'Transmission' connection in GB is defined as 132kV and above in Scotland and Offshore; in England and Wales it is above 132kV. RfG however does not have this distinction. Instead, it refers to connections of greater or less than 110kV. A power generating module directly connecting at greater than 110kV will, if it falls within the scope of the RfG, default to Type D; whilst connecting at below 110kV, the power generating module capacity will determine their band ('A-C').

The GB System Operator performs an annual evaluation of the existing and future connections to the GB energy network based on the best available information in a publication called the Future Energy Scenarios (FES)[6]. This in turn informs an in-depth analysis of system operation provided again by the GB System Operator in the System Operability Framework (SOF)[7]. The wider industry is consulted with in the formation of both documents.

Changes to the type and scale of generation, or concentrations in particular areas of the network, can add to the operational complexities which the System Operator manages, both in real-time and longer-term timescales, which would be a factor in setting the GB banding level.

GB Generation mix

Commercial and political drivers have encouraged progressive connection of renewable generation sources throughout the GB energy network in

[6] http://fes.nationalgrid.com/

[7] http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/System-Operability-Framework

recent years. This has, and continues to, displace traditional thermal plant. Not least has been the increasing trend to connect generation to the distribution network rather the than Transmission system which is starting to have a significant effect on the operational characteristics of the System as a whole.

This thermal plant has traditionally provided the majority of support to the GB System Operator for managing all nature of frequency deviations; either through its inherent inertial capability, or being operated in frequency sensitive mode and being available for response dispatch.

Increasing proliferation of intermittent (variable output) energy sources, which are also non-synchronously connected to the GB network, has increased the regularity and complexity of actions the GB System Operator has had to take in recent years.

Selected charts showing associated GB installed generation capacity trends from the 2017 FES are shown below, highlighting the change to the profile of generation on the system in future years and therefore the potential for increasing system management issues for the GB System Operator.

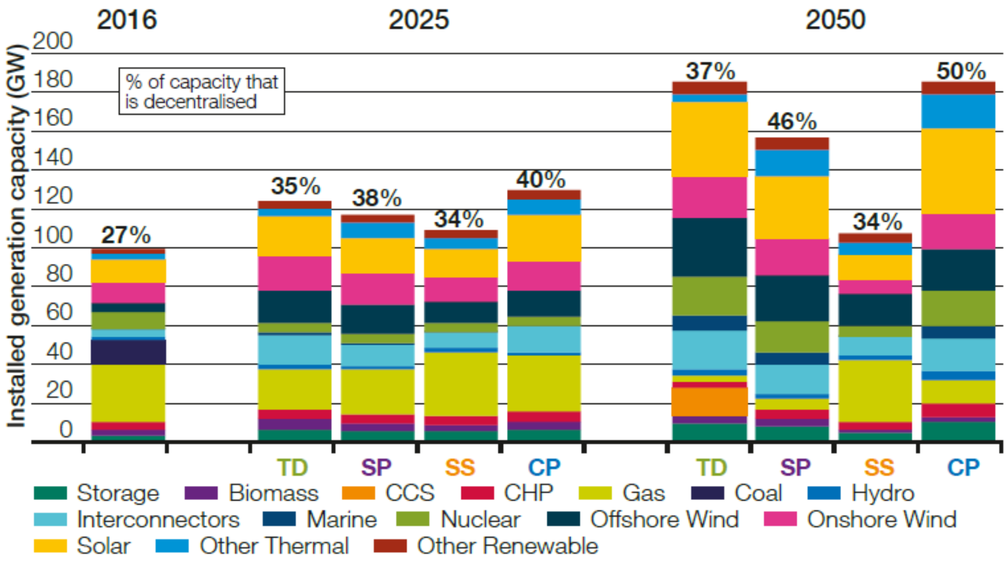
Workgroup Consultation questions- Banding

The GC0100 Workgroup is seeking answers to the following questions set out on the response proforma. The full set of questions can be found in Section 8

Please note that the following questions that can be found on the response proforma:

1. What are the specific costs related to the additional requirements?
2. Do you have any views on the banding thresholds for the original and those suggest for the possible alternative?
3. Can you provide any feedback/comments on the associated legal text?

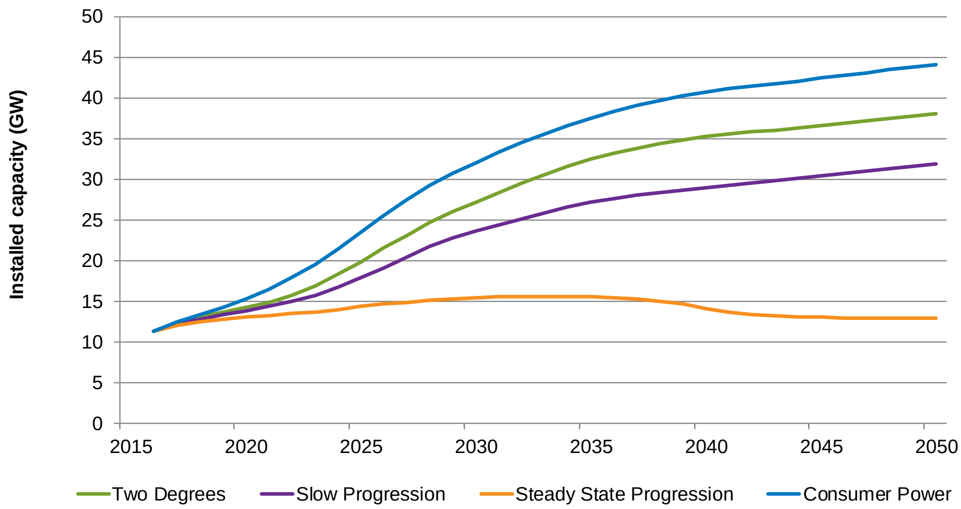
Figure 4.2
Generation capacity by type and proportion of decentralised generation



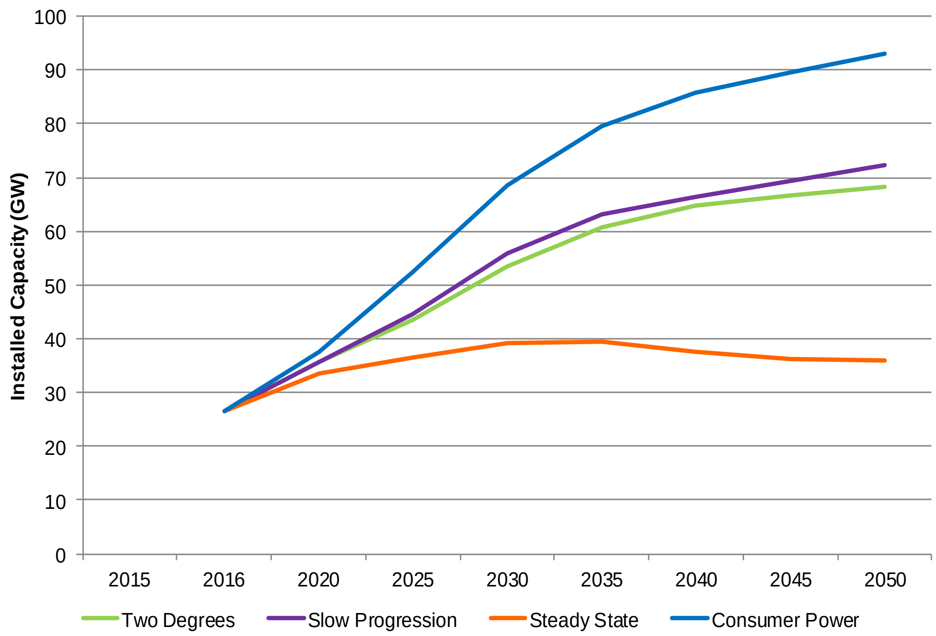
FES scenarios key:

TD – Two Degrees; SP – Slow Progression; SS - Steady State; CP – Consumer Power

Solar installed capacity



Distributed and micro (sub 1MW) capacity



The primary concern from these charts for the GB System Operator is the significant decentralisation of energy from Transmission to Distribution, as well as rapid increases in variable load renewable technologies.

This will require active management, not least in demand forecasting but also issues with voltage caused by demand reduction, reduced inertia and consequently increased RoCoF.

The GB System Operator believes the banding setting process should address the above challenges, affected as it only applies to new generation connections from 2018 onwards.

Notwithstanding the above, these issues are not unique to GB and similar trends are being observed across Europe. As part of RfG implementation, many EU TSOs in other Member States (but not all) have put forward banding proposals which have tended to move away from the maximum levels stipulated in the RfG Network Code.

The Belgian TSO Elia, for example, set out their banding proposals in a public consultation [8]earlier in 2017. It included a table of levels being recommended by adjacent Continental European TSOs.

	Belgium (Elia)	France (RTE)	The Netherland (TENNET BV)[9]	German TSOs[10]
Threshold B	0.25 MW	(0.25MW[11]) 1MW	1MW	0.135 MW
Threshold C	25MW	18MW	50MW	36MW
Threshold D	75MW	75MW	60MW	45MW

4.10 Costs of implementation

This part of the report, prepared by the Proposer, aims to explain the costs related to the proposals set out in this report, based on study work undertaken and included in Annex 5.

Under Transmission system fault conditions, the retained voltage at the connection on the network is a function of the reactive current injected; the greater the reactive current the higher the retained voltage. These conclusions have been demonstrated through the study work completed in the South West of the Transmission system and are believed to be representative of the wider System (see Table 8.1 below).

[8]http://www.elia.be/~/media/files/Elia/users-group/Public%20consultations/2017/20170519_Public-consultation-MAXIMUM-CAPACITY-THRESHOLDS_ENG.pdf

	Area	GC048 study			Future Of Energy documents					
		SCL studied 2025 (kA)	DG installed 2025 (MW)	DG studied 2025 (MW)	FES2025 max DG output (MW)	FES2025 min DG output (MW)	SOF regional SCL min (kA)	SOF regional SCL 95% confidencemin (kA)	SOF regional SCL 95% confidence max (kA)	SOF regional SCL max (kA)
1	North Scotland	N/A	N/A	N/A	1839.5	1167.6	6.8	11.9	16.5	18.6
2	South Scotland	N/A	N/A	N/A	2941.8	2024.4	9.5	13.1	20	21
3	North East England	N/A	N/A	N/A	1360.6	885.4	10.8	14.4	29.3	34.1
4	North West and West Midlands	N/A	N/A	N/A	3338.1	1990.1	0.7	5.7	21.1	22
5	East Midlands	N/A	N/A	N/A	3540.8	2029.3	2.7	7.1	24.4	28.4
6	North Wales	N/A	N/A	N/A	740.1	594.3	13.3	21.6	36.1	38
7	South Wales and West england	N/A	N/A	N/A	3677.3	2300.5	6.4	9.8	26.2	30.4
8	South West England	16.3	2522.4	2411	3213	1999.7	2.4	7.3	22.1	25.9
9	East England	N/A	N/A	N/A	3934.5	2543.1	9.1	17.4	41.5	45.6
10	Greater London	N/A	N/A	N/A	1716	1104.4	6.2	14.2	32.4	35.7
11	South East England	23.95345698	N/A	N/A	2059	1268.2	7.6	15.1	27.9	31.7

Table 8.1 – Comparison of Embedded Generation Backgrounds across GB when compared with South West England

In summary, based on the Fast Fault Current Injection requirements, if the volume of reactive current is delivered in line with FFCI Option 1, then a retained voltage (U_{ret}) for newly connecting Type B, C and D Generators of 0.1 pu can be accommodated. On a short term basis, if either FFCI Options 2 or 3 were selected, it is still possible to still have a retained voltage of 0.1pu but this would need review in the short term, with a view on having something in place by 2020. A conclusion of the study was that should there continue to be a diminishing fall in the volume of Fast Fault Current Injection, then consideration would have to be given to reducing the value of Uret to 0.05pu. Again in the longer term, a value of 0.05pu would not be sustainable as the value of the retained voltage is dependent upon the volume of fast fault current injection. As the volume of fast fault current starts to fall off, then not only does this effect the retained voltage but equally with the drop off in synchronous Generation it becomes increasingly difficult to secure the system.

Further analysis conducted by [National Grid] demonstrated that if the Type B/C banding threshold was set at 50MW instead of 10MW then an additional 21MW of embedded generation would be lost as a result in the depressed voltage across the DNO system. In addition to carrying the infrequent infeed loss required under the SQSS this equates to a cost of approximately £9.2 million (21MW x £50MW/hr x 24x 365) assuming an average reserve cost holding of £50/MWhr. However, some Workgroup members questioned the validity of this number given that the GB System Operator already holds a number of GWs of reserves – given the dynamic, second by second nature of the electrical system it was difficult to envisage how this 21MW (less than 1% of the reserves currently held) of 'extra' reserve could, in practical terms, materialise operationally.

The Proposer noted that if the value of Uret was set at 0.1pu without the volume of expected Fast Fault Current Injection then system studies performed by National Grid demonstrated that some 550MW of Embedded

Generation would be lost on top of that volume of reserve allocated for the infrequent infeed losses under the SQSS. If the average cost of reserve is assumed to be £50/MWhr then this would equate to an approximate cost of 550 x £50 x 24 x 365 = £240.9 million/annum. This is the reserve cost alone, it does not account for additional system measures to prevent system collapse under fault conditions or wider issues such as diminishing inertia which could be very much higher

As the National Grid studies have shown, Fast Fault current is a necessity; it is not an option to have no fault infeed, as the volume of synchronous plant starts to drop away

The Proposer noted that there are ways around this such as the installation of synchronous compensators or pre – curtailment of generation, but the lack of system inertia starts to become increasingly dominant after 2021. It is likely that even if FFCI Option 2 or 3 are used, there may be a need for the use of Synchronous Compensators which are known to address some of these issues. The use of Synchronous Compensators does however present several challenges. Firstly should synchronous compensators be installed by the Generator or the Network Operator and what is the relative cost of this. As a consequence of the physics of the transmission system it is not possible to transport large volumes of Reactive Power across the System. The issue of siting therefore becomes an issue, but equally the location of such devices, especially where there are high volumes of Embedded Generation.

In terms of cost, according to the Proposer a typical synchronous compensator would be estimated to be in the region of £100-£150k/MVAr,for a new installation although this is difficult to quantify as there is little information in the public domain on this subject.

One Workgroup member highlighted the following report http://www.eirgridgroup.com/site-files/library/EirGrid/System-Service-Provision-DNV-KEMA-Report-2012.pdf

Other Workgroup members believed the equipment cost was significantly less than this especially where old refurbished units could be used. Even so there is then the installation cost of the units, their strategic location and running costs. Having said that there may also be the need to install Synchronous compensation equipment within the DNO’s networks which has a cost and also runs the risk of increasing fault levels, the latter issue has an indirect cost impact as there may be a need to uprate and change circuit breakers. There are other industry initiatives; such as project Phoenix, (https://www.ofgem.gov.uk/publications-and-updates/electricity-nic-submission-scottish-power-transmission-phoenix) are looking to address the costs above.

So far as FFCI Option 1 is concerned, the technology fits neatly with storage and solar technologies. In the case of solar technologies it is often common to fit battery technology with the converter. This provides an ideal solution for smaller scale installations and will also reduce the fault infeed that would be observed within the DNO system especially when current limiting controls are added to the converter control.

For generators newly connected via converters and HVDC installations, the issue becomes more of a challenge as it is not usual to fit storage with these types of technologies. There are alternative approaches here these being (i) the plant is deloaded at times of low system inertia upon instruction from the GB System Operator or (ii) Synchronous Compensation equipment is installed within strategic parts of the electrical network. For example in the case of a 750MW HVDC link, without storage but capable of operating in VSM Mode utilising power from the remote end, it would be possible at times of high system inertia (when there is an abundance of synchronous plant on the system) that the link capacity could be increased to 1000MW transfer upon instruction from the GB System Operator. It is acknowledged that Interconnectors have restrictions in terms of their ability to own generation or storage on the same site but this needs to be balanced between commercial opportunities in the market as against technical capabilities.

Due to commercial confidentiality it is difficult to quantify the CAPEX and OPEX costs indicated in the options descriptions in Section 3.3. However, confidential engagement has indicated that that these costs would not be insignificant, certainly in comparison with solar and storage applications where the installation of VSM type technology is believed to be modest. In addition, the use of storage technology coupled with say wind generation does offer the developer a number of choices in so far as the opportunity to participate in Commercial Ancillary Services such as Enhanced Frequency response or to hedge against imbalance which can result from trading in the wholesale electricity market. That said these costs are not insignificant to Generators particular in respect of offshore installations. The consultation will ensure that the ability to supply confidential information to the regulator is highlighted. This may address the concerns of manufacturers providing cost impact.

Finally there is one further cost that needs to be added into the equation which is the corresponding loss in System Inertia. At the present time, this volume is being made up from enhanced frequency response and commercial services for which there is a cost. As the volume of converter based plant increases in the future, this additional system cost can only increase and it is believed that the lowest overall system cost will need to be investigated.

VSM technology does offer some very promising (if yet unproven) capabilities. It is also fully acknowledged that the total costs and options are unclear. The primary aim of this consultation is to define an FFCI, Fault Ride Through and Banding proposal for RfG implementation. For FFCI, two other options (FFCI Option 2 and FFCI Option 3) are also available but should either of these options be selected National Grid would insist an expert group is established to look at the technical capabilities of VSM type technology and other solutions. It would be envisaged that the work would comprise of two elements – the first on the technical challenges of VSM technology and the second on the wider based system approach for managing the growth in converter based plant.

5 Potential Alternatives

During the course of the first four Workgroup meetings a number of potential alternatives to the Original proposal were explored by members of the Workgroup. These potential alternatives were related to (a) banding and (b) removing more stringent requirements - these are explored further below. Additional potential alternatives may also arise from stakeholders, via the Workgroup consultation request(s), or other Workgroup members in due course.

These potential alternative options will be considered by the Workgroup and those potential alternatives that a majority of the Workgroup (or the Workgroup chair) believe better meet the Applicable Grid Code Objectives as compared to the Original will be taken forward as formal Alternatives to the Original proposal (meaning that they will be worked up, legal text prepared and, ultimately, they will be available for Ofgem to approve, if appropriate, and implemented).

The potential alternative forms for this can be found after this text outlining the discussions.

(a) Banding

Workgroup members noted that during the GC0048 Workgroup deliberations three options for the GB banding levels for generation had been developed by that Workgroup and subsequently consulted upon with stakeholders[9]. The option with the most support at that time was one that mirrored the maximum values shown in Table 1 (Article 5) of the RfG. The reasons given for this option included:

Given the reasons set out in the previous GC0048 consultation and responses, a number of Workgroup members were supportive of a potential alternative to the GC0100 original proposal that would set the GB generator banding levels at the maximum level set in the RfG.

[9] See, for example, "GC0048: Requirements for Generators – GB Banding Thresholds" consultation dated 4th April 2016 http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/Modifications/GC0048/

(b) Removing More Stringent Requirements

At the second Workgroup meeting[10] the Proposer confirmed that they will set out in their proposed solution for GC0100 that existing obligations not superseded or replaced by the EU Connection Codes in the GB national network codes (such as, but not limited to, the Grid Code, the Distribution Code, the Engineering Requirements, the CUSC etc.,) would also apply to parties bound by the requirements in the RfG, HVDC and DCC Codes.

In other words the obligations in those EU Network Codes would be applied to future parties connecting, as well as the additional national network code obligations - it was not intended that, in principle, any obligations for future connecting parties would be removed from the national network codes as a result of the GC0100 original proposal.

For the avoidance of doubt, the proposer set out that these requirements would be specific to establishing local connections with a Relevant System Operator where the RfG, HVDC or DCC code is ambiguous or silent; or in relation to operational or planning matters (out of the scope of the EU Connection Codes). The proposer did note that other EU Network Codes, such as System Operation Guideline (SOGL) and Electricity Balancing Guideline (EBGL), will likely supersede most of these specific aspects in future – e.g. data exchange.
However, a Workgroup member identified that this appeared to be incompatible with the requirements of the Third Package, and in particular Articles 8(7) and 21 of Regulation 714/2009[11].

> *Article 8(7)*
> *"The network codes shall be developed for cross-border network issues and market integration issues and shall be without prejudice to the Member States' right to establish national network codes* ***which do not affect cross-border trade****."* [emphasis added]
>
> *Article 21*
> *"This Regulation shall be without prejudice to the rights of Member States to maintain or introduce measures that contain* ***more detailed*** *provisions than those set out herein or in the Guidelines referred to in Article 18."* [emphasis added]

The Workgroup member highlighted that when the RfG was first drafted by ENTSOE (noting that the proposer of GC0100, National Grid, was an active member of the RfG drafting team for ENTSOE) they had included an Article 7, which was subsequently deleted by the Commission on 14th January 2014.

That old Article 7 said the following:

> *"This Network Code shall be* ***without prejudice to the rights of Member States to maintain or introduce measures that contain*** *more detailed or* ***more stringent provisions than those set out***

[10] Held on 6th July 2017
[11] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:211:0015:0035:EN:PDF

***herein**, provided that these measures are compatible with the principles set forth in this Network Code."* [emphasis added]

The Workgroup member noted that the wording of particular relevance to the current discussion are the parts emphasised in bold.

The Workgroup member stated that in their opinion it was clear, by their drafting, that ENTSOE intended to be able to maintain (or introduce later) requirements contained in the existing national network codes[12] where those requirements were (or could be in the future) more stringent than the provisions set out in the EU Network Codes.

The Commission explicitly removed this proposed wording by ENTSOE.

Shortly after the Commission's deletion of the old Article 7 in January 2014, and at the prompting of GB stakeholders (including the Workgroup member who raised this potential alternative) Ofgem enquired of the Commission as to why that article had been deleted.

In their response dated 28th February 2014, the Commission wrote to Ofgem in the following terms:

> *"1. that Article 21 of Regulation (EC) No 714/2009 already provided for the possibility for Member States to adopt **more detailed** measures and that there was thus no need to reiterate this possibility in the ENC RfG"* [emphasis added]
>
> *"2. **the adoption by Member States of measures more stringent than the ones of the ENC RfG** (to the extent of measures with cross-border trade effect) **would not be in line with Article 21 of Regulation (EC) No 714/2009**, i.e. if the Member states were to adopt more stringent measures then it should be proved that there is no cross border trade effect of doing so"* [emphasis added]

This response was shared by Ofgem with GB stakeholders shortly after.

Over a year later, on 26th June 2015, the RfG (and later the DCC and HVDC) Network Code was approved via the Comitology procedure, noting that in doing so, it:

> *"…**provide[s] a clear legal framework for grid connections**, facilitate Union-wide trade in electricity, ensure system security, facilitate the integration of renewable electricity sources, increase competition and allow more efficient use of the network and resources, for the benefit of consumers*"[13] [emphasis added]

As part of that approval process an arrangement was put in place by DECC (later BEIS) and Ofgem to canvass GB stakeholder views on any 'red line' items that the stakeholder(s) believed that DECC and Ofgem should seek to change in each of the respective EU Network Code prior to its approval. The Workgroup member could not recall National Grid

[12] Such as, but not limited to, the Grid Code, the Distribution Code, the Engineering Requirements, the CUSC etc., in GB

[13] RfG, 14th April 2016, Recital 3

identifying, as one of its 'red line' items, the need to allow for more stringent obligations (to those set out in the EU Network Codes) being placed on future connecting parties in GB.

The Workgroup member was also unaware of any other TSO in other Member States having, likewise, raised any similar concerns in respect of more stringent obligations in the intervening seventeen month period (from mid January 2014 to late June 2015) as the RfG Network Code was proceeding though the approvals process.

The Workgroup member stated that in the intervening seventeen month period TSOs could , if they believed this issue to be important, have put forward 'more stringent' obligations if they were required; such as those, for example, needed for maintaining the security of the electrical system; for inclusion in the EU Network Codes. If this had been done at the time then, as such, they would not, in law, be 'more stringent' in terms of Article 8(7) or Article 21 as any obligation(s) would not be in the national network codes (but rather in the EU Network Codes). However, this was not done by the TSOs, despite there being time for them to do so if they wished.

The Workgroup member went on to explain that as s part of the implementation of the EU Network Codes arrangements have been put in place for stakeholder involvement going forward (this is, for example, set out in Article 11 of the RfG, Article 10 of the DCC and Article 11 of the HVDC).

As a result a (‘combined’) stakeholder committee for the three connections codes[14] (RfG, DCC and HVDC) was established in 2016. Chaired by ACER, with secretariat support from ENTSOE it brings together pan European trade associations etc., of stakeholders with interest in the three EU Network Codes relating to connections.

The Workgroup member stated that one of the questions that arose early on in the life of the connections codes stakeholder committee was around applying more stringent requirements within the national network codes.

This question was posed to the Commission in the following terms:

> *“Can a Member State impose more stringent requirements by a separate legislation than imposed by the network code Requirements for Generators (RfGNC)?”*

The Commission's answer to the question was provided in its presentation to the stakeholder committee on 8th September 2016 (which was subsequently repeated at the 9th December 2016 and 7th June 2017 meetings). The answer is as follows:

> “•**In general, no – not outside of the values provided for in the code**. [emphasis added]

[14] Further details, including papers / minutes etc., can be found at https://www.entsoe.eu/major-projects/network-code-implementation/stakeholder-committees/Pages/default.aspx

•But: "*the relevant system operator, in coordination with the relevant TSO, and the power-generating facility owner* ***may agree*** *on wider frequency ranges, longer minimum times for operation or specific requirements for combined frequency and voltage deviations to ensure the best use of the technical capabilities of a power-generating module, if it is required to preserve or to restore system security." Article 13.* [emphasis added]

•*"The network codes shall be developed for cross-border network issues and market integration issues and shall be without prejudice to the Member States' right to establish national network codes* ***which do not affect cross-border trade****." Article 8, Regulation 714.*" [emphasis added]

This issue had also been brought to the attention of GB stakeholders in the spring of 2014 via a presentation which was given to meetings of the three relevant GB stakeholder bodies at that time (ECCAFF, JESG and the joint DECC/Ofgem Stakeholder Group).

That spring 2014 presentation was also shared with the GC0100 Workgroup prior to meeting 3[15] and can be found at Annex 5. The Workgroup member highlighted a number of points in that presentation (some of which have been set out already in the above few paragraphs so are not repeated here), including:

– Firstly: burden of proof to say a particular "more stringent" national measure (over and above the ones of the ENCs) does not affect cross border trade resides with the Member State (not stakeholders)

– Secondly: the presumption for all "more stringent" national measures (over and above the ones of the ENCs) is that they are not legally binding unless and ***until the Member State*** *(not stakeholders)* ***has "proved*** *that there is no cross border trade effect"* [16][emphasis added]

"• In terms of Art 8 and Art 21 what do "...which do not affect cross-border trade..." and "... no cross border trade effect..."mean?

• Important to be mindful of very strong ENTSOe arguments about Type A generators – individually an 800W generator will not affect cross border trade but, cumulatively, they will have an affect on cross border trade" [17]

"• Single GB code requirement:*
– on one generator, maybe a case of there being no cross border affect?
– cumulatively on multiple generators, a case that there is an affect?

[15] Held on 3rd August 2017
[16] Slide titled 'Another point of view (3)'
[17] Slide titled 'Another point of view (4)'

• Multiple GB code requirements:*
– cumulatively on one generator, some cross border affect?
– cumulatively on multiple generators, a clear affect?

• All GB code requirements:*
– cumulatively on one generator, some cross border affect?
– cumulatively on multiple generators, a clear affect?

** document(s) where national requirements are set out - such as GC, DC, DCUSA, BSC, CUSC, Engineering Recommendations (G59 / G83) etc."* [18]

In respect of the affect on cross border trade of obligating future connecting parties in GB, such as generators[19], to meet more stringent requirements than those set out in the respective EU Network Code, the Workgroup member highlighted to the Workgroup twelve examples of additional costs etc., which, in that scenario, a generator could (would?) face.

These examples were:

1) *"pay for the extra obligations to be assessed and the solutions identified;*

2) pay for the extra equipment or pay for the extra procedures to be developed to meet the extra obligations;

3) pay for the operation and maintenance of the extra equipment;

4) pay for the extra operational costs of the procedures (including extra staff);

5) pay for the extra equipment and procedures to be internally(*) tested (prior to the network operator compliance testing);

6) pay for the network operator's compliance testing of the extra equipment and procedures;

7) have to include a risk premium for items (5) and (6) in terms of if the tests are failed or delayed and either (a) remedial actions / costs are incurred to put this right and / or (b) the delay results in the plant not commissioning on time (delaying the revenue income being received);

8) in respect of (7) if the tests under items (5) and (6) fail, then pay for the extra equipment/ procedures changes plus the (re) testing of these elements (or the full rerun of the testing);

9) pay for the replacement costs of the extra equipment either at the end of its design life or if the equipment fails during its operational lifetime;

[18] Slide titled 'Another point of view (5)'
[19] But not limited to generators - the DCC Network Code concerns demand connections and the HVDC Network Code deals with the connection of HVDC systems.

10) have to include a risk premium for the failure of the extra equipment resulting in the plant being non-compliant and the plant being placed off line till the repairs or replacement can be undertaken;

11) in terms of (10) pay for the (re) testing (internal and / or compliance) of the repaired / replaced extra equipment; and (last, but not least)

12) pay the capital cost for all these extra items above, noting that last time we look as an industry at this, the WACC of GB generators was over twice and in some cases more than quadruple that of network operators.

(*) the test is undertaken for the internal purposes of the generator, although the actual testing itself maybe undertake by an external provider, such as the equipment supplier."[20]

The Workgroup member noted that this list is not comprehensive and that other generators may identify additional items that have, inadvertently, been omitted. (e.g. costs associated with compliance with other codes such as mandatory participation in the balancing mechanism for 132 kV connected generators in Scotland > 10 MW) (?)

In the view of the Workgroup member it was clear that the cumulative effect, of all these additional costs[21], on multiple generators in GB, could affect cross border trade; although the Workgroup member acknowledged, as per the Commission's statement[22] of 28th February 2014 to Ofgem, that it was not for the stakeholder, such as a generator, to prove that there was a cross border trade affect, but rather for *those who wish to apply more stringent requirements* (than those in the EU Network Codes) to prove that there is no cross border trade effect of doing so.

The Workgroup member was mindful that the GC0100 proposals would, in due course, be presented to the National Regulatory Authority (Ofgem) for determination. In this context, the Workgroup member was alive to the duty placed upon Ofgem (as the NRA for GB) "to ensure compliance with European Union Law". This was summarised under duties of the regulatory authority; in the Commission's interpretive note on Directive 2009/72 concerning the common rules for the internal market in Electricity (and the Gas equivalent) dated 22nd January 2010[23]; in the following terms:

"Article 37(1)(b) of the Electricity Directive and Article 41(1)(b) of the Gas Directive state that the NRA has the duty of '*ensuring*

[20] Shared with the Workgroup by email on 3rd August 2017

[21] Arising from having to comply with the more stringent national network code obligations which go beyond what is required by the EU Network Code(s)

[22] *"if the Member states were to adopt more stringent measures then it should be proved that there is no cross border trade effect of doing so"*

[23] https://ec.europa.eu/energy/sites/ener/files/documents/2010_01_21_the_regulatory_authorities.pdf

compliance of transmission and distribution system operators, and where relevant, system owners, as well as of any electricity and natural gas undertakings, with their obligations under this Directive and other relevant Community legislation, including as regards cross border issues'.

It follows from this provision that, without prejudice to the rights of the European Commission as guardian of the Treaty on the functioning of the European Union, the NRA is granted a general competence — and the resulting obligation — as regards ensuring general compliance with European Union law. The Commission's services are of the opinion that Article 37(1)(b) of the Electricity Directive, and Article 41(1)(b) of the Gas Directive, are to be seen as a provision guaranteeing that the NRA has the power to ensure compliance with the entire sector specific regulatory '*acquis communautaire*' relevant to the energy market, and this vis-à-vis not only the TSOs but any electricity or gas undertaking."[24]

In light of the above, and given the statement from the GC0100 Proposer noted at the start of this item; together with the presentations (and associated discussions of the 'more stringent' point in terms of compliance) at the 24th July 2017 'Compliance with the RfG' hosted at the ENA; the Workgroup member believed that the original proposal was applying 'more stringent' requirements by applying those additional GB national network codes requirements (outlined above) to future GB connecting parties).

In conclusion, the workgroup member believed it would be <u>incompatible with EU law</u> for the reasons set out above[25] and would thus also not better facilitate Grid Code Applicable Objective (d)[26]:

"To efficiently discharge the obligations imposed upon the licensee by this license and to comply with the Electricity Regulation and any relevant legally binding decisions of the European Commission and/or the Agency"

Therefore, the Workgroup member proposed to bring forward an alternative proposal to the GC0100 original proposal which would be to ensure that more stringent obligations contained within the GB national network codes would not be applicable to future connecting parties who fall within the scope of the RfG, DCC and HVDC Network Codes respectively; although, for the avoidance of doubt, those (GB) national network code obligations would continue to be applicable to 'existing' connected parties (as defined in the RfG, DCC and HVDC Network Codes respectively) unless and until they fall within the scope of the EU Network Codes for connection.

[24] Found at pages 14-15 of the Commission's interpretive note.

[25] As well as, potentially, with respect to Competition Law for the reasons outlined under Section 2 'Governance – Legal Requirements' in the GC0103 proposal: http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/Modifications/GC0103/

[26] Or the Distribution Code equivalent Applicable Objective (iv).

To set this in context the Workgroup member was mindful of the presentation given by the Proposer at the second Workgroup meeting setting out (in a tabular form) the items covered, in the case of generation, with the RfG Network Code for the four types of generation (A-D).

This table is shown below:

Technical Requirements	Type A	Type B	Type C	Type D
Operation across range of frequencies	•	•	•	•
Rate of change of System Frequency (ROCOF)	•	•	•	•
Limited Frequency Sensitive Mode Over Frequency (LFSM-O)	•	•	•	•
Output Power with falling Frequency	•	•	•	•
Logic Interface (input port) to cease active power production	•	•	•	•
Conditions for automatic reconnection	•	•	•	•
Operation across range of frequencies	•	•	•	•
Ability to reduce Active Power on instruction		•	•	•
Fault Ride Through and Fast Fault Current Injection		•	•	•
Conditions for automatic reconnection following disconnection		•	•	•
Protection and Control		•	•	•
Operational Metering		•	•	•
Reactive Capability		•	•	•
Active Power Controlability			•	•
Frequency Response including LFSM-U			•	•
Monitoring			•	•
Robustness			•	•
System Restoration / Black Start			•	•
Simulation Models			•	•
Rates of Change of Active Power			•	•
Earthing			•	•
Enhanced Reactive Capability and control			•	•
Voltage Ranges				•
Enhanced Fault Ride Through				•
Synchronisation				•
Excitation Performance				•

Using this summary table, the Workgroup member identified that with the potential alternative that Type A generators would only be obligated, in terms of their connection to the grid, to those items shown in the table (and so on for Types B, C and D). All other items would be considered more stringent unless it could be proven that there was no cross border trade affect of obligating generators to comply with further obligations over and above those in the RfG (and likewise in terms of the DCC for Demand and the HVDC for HCDV connecting parties).

The proposer, whilst not agreeing with the workgroup member's 'more stringent' interpretation set out above, or indeed that their own solution is 'more stringent', is satisfied that the GC0100 workgroup, the wider industry (through this consultation), the respective Code Panels, and in due course, the National Regulatory Authority, are capable of considering the merits of the respective proposals and that this was fully discussed during the workgroup development of the proposal.

The proposer does however note that whilst various European treaties give the EU competence in the area of energy and creation of the internal energy market, competence on these matters is shared with the Member State. As a general principle therefore, the EU regulations do not encompass everything to do with energy; or mean that everything has to be, or should be, mandated at an EU level.

EU regulation 714/2009 and the Connection Codes themselves address this principle. Article 7 of RfG sets out ‘Regulatory Aspects’, including a provision in clause 3 that when applying the Regulation, Member States, competent entities and system operators shall: “(d) respect the responsibility assigned to the relevant TSO in order to ensure system security, including as required by national legislation;”

The proposer is therefore of the view that a test for stringency should solely be in respect of implementing the specific provisions in the Connection Codes. Other aspects subject to national legislation should not be subject to this test.

Alternative request Proposal form

Grid Code

Modification potential alternative submitted to: *(complete modification number this alternative is being submitted to)*

GC0100

Mod Title: As per original (Banding)

Purpose of alternative Proposal:
As per the Original.

Date submitted to Code Administrator: xxxx

You are: A Workgroup member

Workgroup vote outcome: Formal alternative/not alternative

(Should your potential alternative become a formal alternative it will be allocated a reference)

What stage is this document at?

01	Proposed alternative
02	Formal Workgroup alternative

Any Questions?

Contact:
First Last
Code Administrator

First.Last
@nationalgrid.com

00000 000 000

Alternative Proposer(s):
First Last
Company

First.Last
@xxxxx.com

00000 000 000

Contents

Should you require any guidance or assistance with this form and how to complete it please contact the Code Administrator at grid.code@nationalgrid.com

1 Alternative proposed solution for workgroup review

Workgroup members noted that during the GC0048 Workgroup deliberations three options for the GB banding levels for generation had been developed by that

Workgroup and subsequently consulted upon with stakeholders[1]. The option with the most support at that time was one that mirrored the maximum values shown in Table 1 (Article 5) of the RfG.

The reasons given for this option are set out in the previous GC0048 consultation and responses, a number of Workgroup members were supportive of a potential alternative to the GC0100 original proposal that would set the GB generator banding levels at the maximum level set in the RfG.

2 Difference between this proposal and Original

This proposal will use the RfG maximum values shown in Table 1 (Article 5) of the RfG.

3 Justification for alternative proposal against Grid Code objectives

As per original.

Impact of the modification on the Relevant Objectives:	
Relevant Objective	**Identified impact**
To permit the development, maintenance and operation of an efficient, coordinated and economical system for the transmission of electricity	**Positive**
To facilitate competition in the generation and supply of electricity (and without limiting the foregoing, to facilitate the national electricity transmission system being made available to persons authorised to supply or generate electricity on terms which neither prevent nor restrict competition in the supply or generation of electricity)	**Positive**
Subject to sub-paragraphs (i) and (ii), to promote the security and efficiency of the electricity generation, transmission and distribution systems in the national electricity transmission system operator area taken as a whole	**Positive**
To efficiently discharge the obligations imposed upon the licensee by this license and to comply with the Electricity Regulation and any relevant legally binding decisions of the European Commission and/or the Agency; and	**Positive**
To promote efficiency in the implementation and administration of the Grid Code arrangements	**Neutral**

[1] See, for example, "GC0048: Requirements for Generators – GB Banding Thresholds" consultation dated 4th April 2016 http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/Modifications/GC0048/

In broad term the reasons why this proposal better meet the Applicable Objectives are as per the Original whilst, in addition, also being better in terms of competition in generation by not unduly burdening GB generators with connection obligations that are not commensurate with their plant size.

4 Impacts and Other Considerations

As per the Original.

Consumer Impacts

As per the Original.

5 Implementation

As per the Original.

6 Legal Text

As per the Original, not yet agreed.

Alternative request Proposal form

Grid Code

Modification potential alternative submitted to: *(complete modification number this alternative is being submitted to)*

What stage is this document at?

01	Proposed alternative
02	Formal Workgroup alternative

GC0100

Mod Title: As per original (Removing More Stringent Requirements)

Purpose of alternative Proposal:
As per the Original.

Date submitted to Code Administrator: xxxx

You are: A Workgroup member

Workgroup vote outcome: Formal alternative/not alternative

(Should your potential alternative become a formal alternative it will be allocated a reference)

Any Questions?

Contact:

First Last

Code Administrator

First.Last @nationalgrid.com

00000 000 000

Alternative Proposer(s):

First Last

Company

First.Last @xxxxx.com

00000 000 000

Contents

Should you require any guidance or assistance with this form and how to complete it please contact the Code Administrator at grid.code@nationalgrid.com

1 Alternative proposed solution for workgroup review

Removing More Stringent Requirements

This proposed alternative was raised at the second Workgroup meeting[1] where the Proposer confirmed that it was the intention, with GC0100 (original) that all the existing obligations placed on new connecting parties within the (GB) national network codes (such as, but not limited to, the Grid Code, the Distribution Code, the Engineering Requirements, the CUSC etc.,) would continue (with the GC0100 original proposal) to be applied to future parties connecting under the RfG, DCC and HVDC Network Codes. In other words, the obligations in those EU Network Codes would be applied to future parties connecting whilst retaining all existing national network code obligations. In short, it was not intended that, in principle, any obligations for future connecting parties would be removed from the national network codes as a result of the GC0100 original proposal.

However, a Workgroup member identified that this appeared to be incompatible with the requirements of the Third Package, and in particular Articles 8(7) and 21 of Regulation 714/2009[2].

> *Article 8(7)*
> *"The network codes shall be developed for cross-border network issues and market integration issues and shall be without prejudice to the Member States' right to establish national network codes* ***which do not affect cross-border trade****."* [emphasis added]

> *Article 21*
> *"This Regulation shall be without prejudice to the rights of Member States to maintain or introduce measures that contain* ***more detailed*** *provisions than those set out herein or in the Guidelines referred to in Article 18."* [emphasis added]

The Workgroup member highlighted that when the RfG was first drafted by ENTSOE (noting that the proposer of GC0100, National Grid, was an active member of the RfG drafting team for ENTSOE) they had included an Article 7, which was subsequently deleted by the Commission on 14th January 2014.

That old Article 7 said the following:

> *"This Network Code shall be* ***without prejudice to the rights of Member States to maintain or introduce measures that contain*** *more detailed or* ***more stringent provisions than those set out herein****, provided that these measures are compatible with the principles set forth in this Network Code."* [emphasis added]

Of particular relevance to the currently discussions are the parts emphasised in bold.

It was clear, by their drafting, that ENTSOE intended to be able to maintain (or introduce later) requirements contained in the exiting national network codes[3] where those requirements were (or could be in the future) more stringent than the provisions set out in the EU Network Codes.

The Commission explicitly removed this proposed wording by ENTSOE.

Shortly after the Commission's deletion of the old Article 7 in January 2014, and at the prompting of GB stakeholders (including the Workgroup member who raised this potential alternative) Ofgem enquired of the Commission as to why that article had been deleted.

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[1] Held on 6th July 2017

[2] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:211:0015:0035:EN:PDF

[3] Such as, but not limited to, the Grid Code, the Distribution Code, the Engineering Requirements, the CUSC etc., in GB

In their response dated 28th February 2014, the Commission wrote to Ofgem in the following terms:

> *"1. that Article 21 of Regulation (EC) No 714/2009 already provided for the possibility for Member States to adopt* ***more detailed*** *measures and that there was thus no need to reiterate this possibility in the ENC RfG"* [emphasis added]
>
> *"2.* ***the adoption by Member States of measures more stringent than the ones of the ENC RfG*** *(to the extent of measures with cross-border trade effect)* ***would not be in line with Article 21 of Regulation (EC) No 714/2009****, i.e. if the Member states were to adopt more stringent measures then it should be proved that there is no cross border trade effect of doing so"* [emphasis added]

This response was shared by Ofgem with GB stakeholders (including the proposer of GC0100, National Grid) shortly after.

Over a year later, on 26th June 2015, the RfG (and later the DCC and HVDC) Network Code was approved via the Comitology procedure, noting that in doing so, it:

> *"…****provide[s] a clear legal framework for grid connections****, facilitate Union-wide trade in electricity, ensure system security, facilitate the integration of renewable electricity sources, increase competition and allow more efficient use of the network and resources, for the benefit of consumers*"[4] [emphasis added]

As part of that approval process an arrangement was put in place by DECC (later BEIS) and Ofgem to canvass GB stakeholder views (including from the proposer of GC0100, National Grid) on any 'red line' items that the stakeholder(s) believed that DECC and Ofgem should seek to change in each of the respective EU Network Code prior to its approval. The Workgroup member could not recall National Grid identifying, as one of its 'red line' items, the need to allow for more stringent obligations (to those set out in the EU Network Codes) being placed on future connecting parties in GB.

The Workgroup member was also unaware of any other TSO in other Member States having, likewise, raised any similar concerns in respect of more stringent obligations in the intervening seventeen month period (from mid January 2014 to late June 2015) as the RfG Network Code was proceeding though the approvals process.

Clearly in the intervening seventeen month period TSOs could , if they believed this issue to be important, have put forward 'more stringent' obligations if they were required; such as those, for example, needed for maintaining the security of the electrical system; for inclusion in the EU Network Codes. If this had been done at the time then, as such, they would not, in law, be 'more stringent' in terms of Article 8(7) or Article 21 as any obligation(s) would not be in the national network codes (but rather in the EU Network Codes). However, this was not done by the TSOs, despite there being time for them to do so if they wished.

As part of the implementation of the EU Network Codes arrangements have been put in place for stakeholder involvement going forward (this is, for example, set out in Article 11 of the RfG, Article 10 of the DCC and Article 11 of the HVDC).

[4] RfG, 14th April 2016, Recital 3

As a result a ('combined') stakeholder committee for the three connections codes[5] (RfG, DCC and HVDC) was established in 2016. Chaired by ACER, with secretariat support from ENTSOE it brings together pan European trade associations etc., of stakeholders with interest in the three EU Network Codes relating to connections.

One of the questions that arose early on in the life of the connections codes stakeholder committee was around applying more stringent requirements within the national network codes.

This question was posed to the Commission in the following terms:

> *"Can a Member State impose more stringent requirements by a separate legislation than imposed by the network code Requirements for Generators (RfGNC)?"*

The Commission's answer to the question was provided in its presentation to the stakeholder committee on 8th September 2016 (which was subsequently repeated at the 9th December 2016 and 7th June 2017 meetings). The answer is as follows:

> "•**In general, no – not outside of the values provided for in the code**. [emphasis added]
>
> •But: "*the relevant system operator, in coordination with the relevant TSO, and the power-generating facility owner **may <u>agree</u>** on wider frequency ranges, longer minimum times for operation or specific requirements for combined frequency and voltage deviations to ensure the best use of the technical capabilities of a power-generating module, if it is required to preserve or to restore system security." Article 13.* [emphasis added]
>
> •*"The network codes shall be developed for cross-border network issues and market integration issues and shall be without prejudice to the Member States' right to establish national network codes **which do not affect cross-border trade**." Article 8, Regulation 714.*" [emphasis added]

This issue had also been brought to the attention of GB stakeholders (including the proposer of GC0100, National Grid) in the spring of 2014 via a presentation which was given to meetings of the three relevant GB stakeholder bodies at that time (ECCAFF, JESG and the joint DECC/Ofgem Stakeholder Group).

That spring 2014 presentation was also shared with the GC0100 Workgroup prior to meeting 3[6]. The Workgroup member highlighted a number of points in that presentation (some of which have been set out already in the above few paragraphs so are not repeated here), including:

> *– Firstly: burden of proof to say a particular "more stringent" national measure (over and above the ones of the ENCs) does not affect cross border trade resides with the Member State (not stakeholders)*
>
> *– Secondly: the presumption for all "more stringent" national measures (over and above the ones of the ENCs) is that they are not legally binding*

[5] Further details, including papers / minutes etc., can be found at https://www.entsoe.eu/major-projects/network-code-implementation/stakeholder-committees/Pages/default.aspx

[6] Held on 3rd August 2017

*unless and **until the Member State** (not stakeholders) **has "proved** that there is no cross border trade effect"* [7][emphasis added]

"• In terms of Art 8 and Art 21 what do "...which do not affect cross-border trade..." and "... no cross border trade effect..."mean?

• Important to be mindful of very strong ENTSOe arguments about Type A generators – individually an 800W generator will not affect cross border trade but, cumulatively, they will have an affect on cross border trade" [8]

"• Single GB code requirement:*
– on one generator, maybe a case of there being no cross border affect?
– cumulatively on multiple generators, a case that there is an affect?

• Multiple GB code requirements:*
– cumulatively on one generator, some cross border affect?
– cumulatively on multiple generators, a clear affect?

• All GB code requirements:*
– cumulatively on one generator, some cross border affect?
– cumulatively on multiple generators, a clear affect?

** document(s) where national requirements are set out - such as GC, DC, DCUSA, BSC, CUSC, Engineering Recommendations (G59 / G83) etc."* [9]

In respect of the effect on cross border trade of obligating future connecting parties in GB, such as generators[10], to meet more stringent requirements than those set out in the respective EU Network Code, the Workgroup member highlighted to the Workgroup twelve examples of additional costs etc., which, in that scenario, a generator could (would?) face.

These examples were:

1) "pay for the extra obligations to be assessed and the solutions identified;

2) pay for the extra equipment or pay for the extra procedures to be developed to meet the extra obligations;

3) pay for the operation and maintenance of the extra equipment;

4) pay for the extra operational costs of the procedures (including extra staff);

5) pay for the extra equipment and procedures to be internally(*) tested (prior to the network operator compliance testing);

6) pay for the network operator's compliance testing of the extra equipment and procedures;

7) have to include a risk premium for items (5) and (6) in terms of if the tests are failed or delayed and either (a) remedial actions / costs are incurred to put this right and / or (b) the delay results in the plant not commissioning on time (delaying the revenue income being received);

[7] Slide titled 'Another point of view (3)'
[8] Slide titled 'Another point of view (4)'
[9] Slide titled 'Another point of view (5)'
[10] But not limited to generators - the DCC Network Code concerns demand connections and the HVDC Network Code deals with the connection of HVDC systems.

8) in respect of (7) if the tests under items (5) and (6) fail, then pay for the extra equipment/ procedures changes plus the (re) testing of these elements (or the full rerun of the testing);

9) pay for the replacement costs of the extra equipment either at the end of its design life or if the equipment fails during its operational lifetime;

10) have to include a risk premium for the failure of the extra equipment resulting in the plant being non compliant and the plant being placed off line till the repairs or replacement can be undertaken;

11) in terms of (10) pay for the (re) testing (internal and / or compliance) of the repaired / replaced extra equipment; and (last, but not least)

12) pay the capital cost for all these extra items above, noting that last time we look as an industry at this, the WACC of GB generators was over twice and in some cases more than quadruple that of network operators.

(*) the test is undertaken for the internal purposes of the generator, although the actual testing itself maybe undertake by an external provider, such as the equipment supplier."[11]

The Workgroup member noted that this list is not comprehensive and that other generators may identify additional items that have, inadvertently, been omitted. (e.g costs associated with compliance with other codes such as mandatory participation in the balancing mechanism for 132 kV connected generators in Scotland > 10 MW) (?)

In the view of the Workgroup member it was clear that the cumulative effect, of all these additional costs[12], on multiple generators in GB, would affect cross border trade; although the Workgroup member acknowledged, as per the Commission's statement[13] of 28th February 2014 to Ofgem, that it was not for the stakeholder, such as a generator, to prove that there was a cross border trade affect, but rather for *those who wish to apply more stringent requirements* (than those in the EU Network Codes) to prove that there is no cross border trade effect of doing so.

The Workgroup member was mindful that the GC0100 proposals would, in due course, be presented to the National Regulatory Authority (Ofgem) for determination. In this context, the Workgroup member was alive to the duty placed upon Ofgem (as the NRA for GB) "to ensure compliance with European Union Law". This was summarised under duties of the regulatory authority; in the Commission's interpretive note on Directive 2009/72 concerning the common rules for the internal market in Electricity (and the Gas equivalent) dated 22nd January 2010[14]; in the following terms:

> "Article 37(1)(b) of the Electricity Directive and Article 41(1)(b) of the Gas Directive state that the NRA has the duty of '*ensuring compliance of transmission and distribution system operators, and where relevant,*

[11] Shared with the Workgroup by email on 3rd August 2017

[12] Arising from having to comply with the more stringent national network code obligations which go beyond what is required by the EU Network Code(s)

[13] "*if the Member states were to adopt more stringent measures then it should be proved that there is no cross border trade effect of doing so*"

[14] https://ec.europa.eu/energy/sites/ener/files/documents/2010_01_21_the_regulatory_authorities.pdf

system owners, as well as of any electricity and natural gas undertakings, with their obligations under this Directive and other relevant Community legislation, including as regards cross border issues'.

It follows from this provision that, without prejudice to the rights of the European Commission as guardian of the Treaty on the functioning of the European Union, the NRA is granted a general competence — and the resulting obligation — as regards ensuring general compliance with European Union law. The Commission's services are of the opinion that Article 37(1)(b) of the Electricity Directive, and Article 41(1)(b) of the Gas Directive, are to be seen as a provision guaranteeing that the NRA has the power to ensure compliance with the entire sector specific regulatory '*acquis communautaire*' relevant to the energy market, and this vis-à-vis not only the TSOs but any electricity or gas undertaking."[15]

In light of the above, and given the statement from the GC0100 Proposer noted at the start of this item; together with the presentations (and associated discussions of the 'more stringent' point in terms of compliance) at the 24th July 2017 'Compliance with the RfG' hosted at the ENA; the Workgroup member believed that the original proposal (by virtue of not removing 'more stringent' requirements contained within the GB national network codes, that it was proposed to apply to future GB connecting parties) would be incompatible with EU law for the reasons set out above[16] and would thus also not better facilitate Grid Code Applicable Objective (d)[17]:

"To efficiently discharge the obligations imposed upon the licensee by this license and to comply with the Electricity Regulation and any relevant legally binding decisions of the European Commission and/or the Agency"

Therefore, the Workgroup proposed to bring forward an alternative proposal to the GC0100 original proposal which would be to ensure that more stringent obligations contained within the GB national network codes would not be applicable to future connecting parties who fall within the scope of the RfG, DCC and HVDC Network Codes respectively; although, for the avoidance of doubt, those (GB) national network code obligations would continue to be applicable to 'existing' connected parties (as defined in the RfG, DCC and HVDC Network Codes respectively) unless and until they fall within the scope of the EU Network Codes for connection.

To set this in context the Workgroup member was mindful of the presentation given by the Proposer at the second Workgroup meeting setting out (in a tabular form) the items covered, in the case of generation, with the RfG Network Code for the four types of generation (A-D).

This table is shown below:

[15] Found at pages 14-15 of the Commission's interpretive note.

[16] As well as, potentially, with respect to Competition Law for the reasons outlined under Section 2 'Governance – Legal Requirements' in the GC0103 proposal: http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/Modifications/GC0103/

[17] Or the Distribution Code equivalent Applicable Objective (iv).

Technical Requirements	Type A	Type B	Type C	Type D
Operation across range of frequencies	•	•	•	•
Rate of change of System Frequency (ROCOF)	•	•	•	•
Limited Frequency Sensitive Mode Over Frequency (LFSM-O)	•	•	•	•
Output Power with falling Frequency	•	•	•	•
Logic Interface (input port) to cease active power production	•	•	•	•
Conditions for automatic reconnection	•	•	•	•
Operation across range of frequencies	•	•	•	•
Ability to reduce Active Power on instruction		•	•	•
Fault Ride Through and Fast Fault Current Injection		•	•	•
Conditions for automatic reconnection following disconnection		•	•	•
Protection and Control		•	•	•
Operational Metering		•	•	•
Reactive Capability		•	•	•
Active Power Controlability			•	•
Frequency Response including LFSM-U			•	•
Monitoring			•	•
Robustness			•	•
System Restoration / Black Start			•	•
Simulation Models			•	•
Rates of Change of Active Power			•	•
Earthing			•	•
Enhanced Reactive Capability and control			•	•
Voltage Ranges				•
Enhanced Fault Ride Through				•
Synchronisation				•
Excitation Performance				•

Using this summary table, the Workgroup member identified that with the potential alternative that Type A generators would only be obligated, in terms of their connection to the grid, to those items shown in the table (and so on for Types B, C and D). All other items would be considered more stringent unless it could be proven that there was no cross border trade affect of obligating generators to comply with further obligations over and above those in the RfG (and likewise in terms of the DCC for Demand and the HVDC for HCDV connecting parties).

2 Difference between this proposal and Original

This proposal will ensure that the GB code changes set out in GC0100 are not more stringent than the requirements set out in the RfG.

3 Justification for alternative proposal against Grid Code objectives

As per original.

Impact of the modification on the Relevant Objectives:	
Relevant Objective	**Identified impact**
To permit the development, maintenance and operation of an efficient, coordinated and economical system for the transmission of electricity	**Positive**
To facilitate competition in the generation and supply of electricity (and without limiting the foregoing, to facilitate the national electricity transmission system being made available to persons authorised to supply or generate electricity on terms which neither prevent nor restrict competition in the supply or generation of electricity)	**Positive**
Subject to sub-paragraphs (i) and (ii), to promote the security and efficiency of the electricity generation, transmission and distribution systems in the national electricity transmission system operator area taken as a whole	**Positive**
To efficiently discharge the obligations imposed upon the licensee by this license and to comply with the Electricity Regulation and any relevant legally binding decisions of the European Commission and/or the Agency; and	**Positive**
To promote efficiency in the implementation and administration of the Grid Code arrangements	**Positive**

In broad term the reasons why this proposal better meet the Applicable Objectives are as per the Original whilst, in addition, ensuring that the proposal is compliant with the Electricity Regulation and the EU Network (connection) Codes as the original proposal; in applying more stringent requirements on connecting generators, demand facilities and HVDC system than permitted by the EU Network (connection) Codes; is incompatible with the Electricity Regulation and the EU Network (connection) Codes.

Furthermore, when compared with the original, this alternative also better facilitates efficiency in the implementation and administration of the Code arrangements as it ensure that the solution to the Original defect is approvable and implementable.

4 Impacts and Other Considerations

As per the Original.

Consumer Impacts

As per the Original.

5 Implementation

As per the Original.

6 Legal Text

As per the Original, not yet agreed.

Impact and Assessment

Impact on the Grid Code

This modification is necessary to ensure the Grid Code is consistent with the applicable European Network Code requirements identified for this modification.

To apply these requirements, a new section to the Grid Code Connection Conditions specific to EU requirements will be introduced. Users bound by these EU requirements (as determined in the Network Codes themselves) will need to comply with this new section. Existing Grid Code Users will not be bound by this a new section to the Grid Code Connection Conditions specific to EU requirements (unless and until they fall within the scope of those EU Network Codes).

Impact on the Distribution Code

A similar approach will be taken with the Distribution Code. Existing generating equipment will continue to be bound by G59 and G83 (as appropriate to the equipment's size) which will remain unchanged. New generating equipment will be required to be compliant with two new documents, G99 and G98 (again as appropriate to size and/or compliance arrangements)

Impact on Greenhouse Gas Emissions

The proposed modification should better facilitate connection of renewable low-carbon generation schemes in GB, thus having a positive impact on greenhouse gas emissions.

Impact on Core Industry Documents

Minor consequential changes are anticipated subsequent to this Grid Code modification in the STC and the Relevant Electrical Standards, to align them with the proposed changes.

Impact on EU Network Codes

This modification has been raised solely to implement EU Network Codes into the existing GB regulatory frameworks in a way that is not more stringent than required by those Network Codes. It is therefore fundamental in ensuring the (GB) Member State compliance with the EU Connection Codes specifically.

Impact on Consumers

This modification facilitates the implementation of consistent technical standards across the EU for the connection of new Generation or HVDC equipment. This should reduce development costs for new projects which should result in cost savings passed on to end consumers. Further consideration of compliance costs to these proposals is considered in the 'Costs of implementation' section below

Does this modification impact a Significant Code Review (SCR) or other significant industry change projects, if so, how?

The EU Network Code implementation is being undertaken as a significant programme of work within the GB industry. This mod forms part of that programme, but is not part of an on-going SCR.

6 Relevant Objectives – Initial assessment by Proposer

Impact of the modification on the Applicable Grid Code Objectives:	
Relevant Objective	Identified impact (Positive/negative/neutral)
(a) To permit the development, maintenance and operation of an efficient, coordinated and economical system for the transmission of electricity;	Positive
(b) To facilitate competition in the generation and supply of electricity (and without limiting the foregoing, to facilitate the national electricity Transmission system being made available to persons authorised to supply or generate electricity on terms which neither prevent nor restrict competition in the supply or generation of electricity);	Positive
(c) Subject to sub-paragraphs (i) and (ii), to promote the security and efficiency of the electricity generation, transmission and Distribution systems in the national electricity Transmission system operator area taken as a whole;	Positive
(d) To efficiently discharge the obligations imposed upon the licensee by this license and to comply with the Electricity Regulation and any relevant legally binding decisions of the European Commission and/or the Agency; and	Positive
(e) To promote efficiency in the implementation and administration of the Grid Code arrangements	Neutral

Impact of the modification on the Applicable Distribution Code Objectives:	
Relevant Objective	Identified impact (Positive/negative/neutral)
(i) To permit the development, maintenance and operation of an efficient, coordinated and economical system for the distribution of electricity	Positive
(ii) To facilitate competition in the generation and supply of electricity	Positive
(iii) efficiently discharge the obligations imposed upon distribution licensees by the distribution licences and comply with the Regulation and any relevant legally binding decision of the European Commission and/or the Agency for the Co-operation of Energy Regulators; ; and	Positive
(iv) promote efficiency in the implementation and administration of the Distribution Code	Positive

The EU Connection Codes derive from the Third Energy Package legislation which is focused on delivering security of supply; supporting the connection of new renewable plant; and increasing competition to lower end consumer costs. It therefore directly supports the first three Grid Code objectives.

Furthermore, this modification is to ensure GB compliance of EU legislation in a timely manner, which positively supports the fourth Grid Code applicable objective.

7 Implementation

This modification must be in place to ensure the requirements of the EU Connection Codes are set out in the GB codes by two years from the respective Entry Into Force dates (set out earlier in this Consultation).

It is therefore crucial that this work is concluded swiftly to allow the industry the maximum amount of time to consider what they need to do to arrange compliance.

This modification is required to be implemented onto the Grid Code on 16 May 2018.

8 Workgroup Consultation questions

The GC0100 Workgroup is seeking the views of Grid Code Users and other interested parties in relation to the issues noted in this document and specifically in response to the questions highlighted in the report and summarised below:

Standard Workgroup Consultation questions:

1. Do you believe that GC0100 original proposal better facilitate the Applicable Grid Code Objectives?
2. Do you support the proposed implementation approach?
3. Do you have any other comments?
4. Do you wish to raise a Workgroup Consultation Alternative request for the Workgroup to consider? The form to complete can be found here: http://www2.nationalgrid.com/uk/industry-information/electricity-codes/grid-code/modifications/forms-and-guidance/

Specific GC0100 Workgroup Consultations:

5. Removing More Stringent Requirements' concerns have been expressed by some Workgroup members that applying more stringent requirement on newly connecting parties (that fall within this scope of the EU Network Codes for generation, demand and HVDC systems) maybe incompatible with EU law. Do you have any views on this topic that could assist the Workgroup when they are considering the topic in due course?
6. Are you comfortable with using the EU definition of Maximum Capacity instead of the GB definition of "Registered Capacity"?

Fast Fault Current Injection

7. What are your views on options 1, 2 and 3 as set out in paragraph 4.4 for Fast Fault Current Injection and which option (if any) would you prefer?

8. Do you have any alternative fast fault current injection solutions noting that the requirement applies to the Converter not the wider Power System?
9. In considering the three Fast Fault Current Injection options 1, 2 and 3 in paragraph 4.4 do you have any comments in relation to technology readiness, cost implications, and can they be implemented date within the context of product development timescales?
10. Do you have any evidence to support your views?
11. Do you have any views on the specific costs related to the additional requirements?
12. Is the current proposed wording for the remote end HVDC and DC Connected Power park modules sufficient to facilitate future new technology?

Banding

13. What are the specific costs related to the additional requirements?
14. Do you have any views on the banding thresholds for the original and those suggest for the possible alternative?
15. Can you provide any feedback/comments on the associated legal text?

Fault Ride Through

16. Do you support the fault ride through voltage against time curves If not please state why you disagree, what alternative you would recommend and your justification for any alternative?
17. Do you have any specific views about the proposal to modify the stage 2 under voltage protection for distributed generation interface protection?

Other questions

18. Does the Legal drafting contained in annex 2 and 3 deliver the intent of the solution outlined in section 3?
19. Do you have any information based on the proposed solution in respect of implementation costs?

Please send your response using the Response Proforma which can be found on the National Grid website via the following link:

http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/Modifications/GC0100/

In accordance with Governance Rules Section 8 of the Grid Code, Any Authorised Electricity Operator; the Citizens Advice or the Citizens Advice Scotland, NGET or a Materially Affected Party may (subject to GR.20.17) raise a Workgroup Consultation Alternative Request. If you wish to raise such a request, please use the relevant form available at the weblink below:

http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/Modifications/Forms-and-guidance/

Views are invited upon the proposals outlined in this report, which should be received by **5pm** on **2 October 2017.** Your formal responses may be emailed to: grid.code@nationalgrid.com

If you wish to submit a confidential response, please note that information provided in response to this consultation will be published on National Grid's website unless the response is clearly marked "Private & Confidential", we will contact you to establish the extent of the confidentiality. A response market "Private & Confidential" will be disclosed to the Authority in full but, unless agreed otherwise, will not be shared with the Grid Code Review Panel or the industry and may therefore not influence the debate to the same extent as a non-confidential response.

Please note an automatic confidentiality disclaimer generated by your IT System will not in itself, mean that your response is treated as if it had been marked "Private and Confidential".

Please note that you can also send responses directly to the Authority.

Annex 1 – Terms of Reference

nationalgrid

Workgroup Terms of Reference and Membership

TERMS OF REFERENCE FOR GC0100 WORKGROUP

EU Connection Code Mod 1

Responsibilities

1. The Workgroup is responsible for assisting the Grid Code Review Panel in the evaluation of Grid Code Modification Proposal **GC0100, *EU Connection Code Mod 1*** tabled by National Grid at the Grid Code Review Panel meeting on 30 May 2017.

2. The proposal must be evaluated to consider whether it better facilitates achievement of the Grid Code Objectives. These can be summarised as follows:

   (i) To permit the development, maintenance and operation of an efficient, coordinated and economical system for the transmission of electricity;

   (ii) To facilitate competition in the generation and supply of electricity (and without limiting the foregoing, to facilitate the national electricity transmission system being made available to persons authorised to supply or generate electricity on terms which neither prevent nor restrict competition in the supply or generation of electricity);

   (iii) Subject to sub-paragraphs (i) and (ii), to promote the security and efficiency of the electricity generation, transmission and distribution systems in the national; and

   (iv) To efficiently discharge the obligations imposed upon the licensee by this license and to comply with the Electricity Regulation and any relevant legally binding decisions of the European Commission and/or the Agency. In conducting its business, the Workgroup will at all times endeavour to operate in a manner that is consistent with the Code Administration Code of Practice principles.

Scope

3. The Workgroup must consider the issues raised by the Modification Proposal and consider if the proposal identified better facilitates achievement of the Grid Code Objectives.

4. In addition to the overriding requirement of point 3 above, the Workgroup shall consider and report on the following specific issues:

   a) Implementation;
   b) Review draft legal text should it have been provided. If legal text is not submitted within the Grid Code Modification Proposal the Workgroup should be instructed to assist in the developing of the legal text; and
   c) Consider whether any further Industry experts or stakeholders should be invited to participate within the Workgroup to ensure that all potentially affected stakeholders have the opportunity to be represented in the Workgroup.

   Modify the Grid Code and Distribution Code to specify in GB:*
   d) the scope and applicability of the EU requirements under RfG, HVDC and DCC, including to heavily modified 'existing' users;

e) *the four Type (A-D) banding levels under RfG for the GB synchronous area, plus set out the process for any future reviews;*
f) *the Fault Ride Through requirements under RfG and HVDC;*
g) *the Fast Fault Current Injection requirements under RfG;*

5. As per Grid Code GR20.8 (a) and (b) the Workgroup should seek clarification and guidance from the Grid Code Review Panel when appropriate and required.

6. The Workgroup is responsible for the formulation and evaluation of any Workgroup Alternative Grid Code Modifications arising from Group discussions which would, as compared with the Modification Proposal or the current version of the Grid Code, better facilitate achieving the Grid Code Objectives in relation to the issue or defect identified.

7. The Workgroup should become conversant with the definition of Workgroup Alternative Grid Code Modification which appears in the Governance Rules of the Grid Code. The definition entitles the Group and/or an individual member of the Workgroup to put forward a Workgroup Alternative Code Modification proposal if the member(s) genuinely believes the alternative proposal compared with the Modification Proposal or the current version of the Grid Code better facilitates the Grid Code objectives The extent of the support for the Modification Proposal or any Workgroup Alternative Modification (WACM) proposal WACM arising from the Workgroup's discussions should be clearly described in the final Workgroup Report to the Grid Code Review Panel.

8. Workgroup members should be mindful of efficiency and propose the fewest number of WACM proposals as possible. All new alternative proposals need to be proposed using the Alternative request Proposal form ensuring a reliable source of information for the Workgroup, Panel, Industry participants and the Authority.

9. All WACM proposals should include the Proposer(s)'s details within the final Workgroup report, for the avoidance of doubt this includes WACM proposals which are proposed by the entire Workgroup or subset of members.

10. There is an option for the Workgroup to undertake a period of Consultation in accordance with Grid Code GR. 20.11, if defined within the timetable agreed by the Grid Code Panel. Should the Workgroup determine that they see the benefit in a Workgroup Consultation being issued they can recommend this to the Grid Code Review Panel to consider.

11. Following the Consultation period the Workgroup is required to consider all responses including any Workgroup Consultation Alternative Requests. In undertaking an assessment of any Workgroup Consultation Alternative Request, the Workgroup should consider whether it better facilitates the Grid Code Objectives than the current version of the Grid Code.

12. As appropriate, the Workgroup will be required to undertake any further analysis and update the appropriate sections of the original Modification Proposal and/or WACM proposals (Workgroup members cannot amend the original text submitted by the Proposer of the modification) All responses including any Workgroup Consultation Alternative Requests shall be included within the final report including a summary of the Workgroup's deliberations and conclusions. The report should make it clear where and why the Workgroup chairman has exercised their right under the Grid Code to progress a Workgroup Consultation Alternative Request or a WACM proposal against the majority views of Workgroup members. It should also be explicitly stated where, under these circumstances, the Workgroup chairman is employed by the same organisation who submitted the Workgroup Consultation Alternative Request.

13. The Workgroup is to submit its final report to the Modifications Panel Secretary on 7 November 2017 for circulation to Panel Members. The final report conclusions will be presented to the Grid Code Review Panel meeting on 15 November 2017.

Membership

It is recommended that the Workgroup has the following members:

Role	Name	Representing (User nominated)
Chair	John Martin	Code Administrator
Technical Secretary	Chrissie Brown	Code Administrator
National Grid Representative*	Richard Woodward	National Grid Electricity Transmission
Industry Representative*	Isaac Gutierrez	Scottish Power Renewables
	Gregory Middleton	Deep Sea Plc
	David Spillet	Energy Networks Association
	Alastair Frew/ Rui Rui	Scottish Power
	Paul Youngman	Drax Power
	Graeme Vincent	Scottish Power Energy Networks
	Sridhar Sahukari	DONG
	Andrew Vaudin	EDF Energy
	Alan Creighton	Northern Power Grid
	John Gleadow	NorthConnect KS
	Marko Grizelj/ Chandu Bapatu	Siemens
	Hayden Scott-Dye	Tidal Lagoon Power
	Paul Graham	UK Power Reserve
	Peter Bolitho	Waterswye
	Mick Barlow	S & C
	Tim Ellingham/ Peter Woodcock	RWE
	Damian Jackman/Garth Graham	SSE Generation Ltd
	John Parsons	Beama
	Alan Creighton	Northern Powergrid
	Ushe Mupambireyi/ Erwann Mauxion	GE
	Mike Kay	ENA(Electricity North West)
	Awais Lodhi	Centrica
	Dave Draper	Horizon Nuclear Power
	Konstantinos Pierros	ENERCON GmbH
	Christopher Smith	National Grid Ventures
	Chris Marsland	Trade body representative
Authority Representative	Stephen Perry	Ofgem
Observer	Nicholas Rubin	Elexon
	Frank Martin	Siemens
	Sarah Carter	Ricardo Energy

14. A (*) Workgroup must comprise at least xx members (who may be Panel Members). The roles identified with an asterisk(*) in the table above contribute toward the required quorum, determined in accordance with paragraph 15 below.

15. The Grid Code Review Panel must agree a number that will be quorum for each Workgroup meeting. The agreed figure for GC0100 is that at least 5 Workgroup members must participate in a meeting for quorum to be met.

16. A vote is to take place by all eligible Workgroup members on the Modification Proposal and each WACM proposal and Workgroup Consultation Alternative Request based on their assessment of the Proposal(s) against the Grid Code objectives when compared against the current Grid Code baseline.

    - Do you support the Original or any of the alternative Proposals?
    - Which of the Proposals best facilitates the Grid Code Objectives?

    The Workgroup chairman shall not have a vote, casting or otherwise.

    The results from the vote and the reasons for such voting shall be recorded in the Workgroup report in as much detail as practicable.

17. It is expected that Workgroup members would only abstain from voting under limited circumstances, for example where a member feels that a proposal has been insufficiently developed. Where a member has such concerns, they should raise these with the Workgroup chairman at the earliest possible opportunity and certainly before the Workgroup vote takes place. Where abstention occurs, the reason should be recorded in the Workgroup report.

18. Workgroup members or their appointed alternate are required to attend a minimum of 50% of the Workgroup meetings to be eligible to participate in the Workgroup vote.

19. The Technical Secretary shall keep an Attendance Record for the Workgroup meetings and circulate the Attendance Record with the Action Notes after each meeting. This will be attached to the final Workgroup report.

20. The Workgroup membership can be amended from time to time by the Grid Code Review Panel and the Chairman of the Workgroup.

Appendix 1 – Indicative Workgroup Timetable

The following timetable is indicative for GC0100:

Date	Meeting
Workgroup Meeting 1	7 June 2017
Workgroup Meeting 2	6 July 2017
Workgroup Meeting 3	3 August 2017
Workgroup Consultation issued (15 Working days)	TBC August 2017 (Close: September 2017)
Workgroup meeting	September 2017
Workgroup meeting (WACMs and vote)	October 2017
Workgroup Report presented to Panel	7 November 2017 (Panel: 15 November 2017)

Post Workgroup modification process:

Date	Meeting
Code Administration Consultation Report issued to the Industry (15 Working Days)	17 November 2017 (Close: 8 December 2017)
Draft Modification Report issued to Industry and GCRP Panel (5WDs)	11 December 2017 (Close: 18 December 2017)
Draft Final Modification Report presented to Panel	12 December 2017
Modification Panel Recommendation Vote (5	20 December 2017

WDs for Panel comment)	
Final Modification Report submitted to the Authority	10 January 2018
Authority Decision (25WDs)	14 February 2018
Implementation	1 March 2018

Annex 2 – GC0100 Draft Grid Code Legal Text

Given their size, the proposed legal text is provided in separate files.

Annex 3 - G99 Distribution Code draft legal text

Given their size, the proposed legal text is provided in separate files.

Annex 4- References

[1] GC0062 Fault ride through Consultation available at:- http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=45284

[2] H/04- Changes to Incorporate New Generation Technologies and DC Inter-connectors (Generic Provisions):- available at:- http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=13419

[3] ENTSO-E- Frequently asked questions document :- available at:_ https://www.entsoe.eu/fileadmin/user_upload/_library/consultations/Network_Code_RfG/120626_-_NC_RfG_-_Frequently_Asked_Questions.pdf

[4] RTE Documentation technique de reference, Article 4.3 – Stabilité, Installation raccordée au réseau d'interconnexion: http://clients.rte france.com/htm/fr/mediatheque/telecharge/reftech/01-09-14_complet.pdf available at:-https://clients.rte-france.com/htm/fr/mediatheque/telecharge/reftech/01-09-14_complet.pdf

[5] GC0035 - Frequency Changes during Large Disturbances and their effect on the total system - Phase – available at:- 1http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/Modifications/GC0035-GC0079/

Annex 5 - System Study Results in Slide format

Insert Slide Presentation – June Meeting (.pdf)

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GC0100 - Fast Fault Current Injection, Fault Ride Through and Banding

Antony Johnson

July 2017

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Summary

- Overview - why are Fast Fault Current Injection, Fault Ride Through and Banding related
- Proposals
  - Fast Fault Current Injection
  - Fault ride Through
  - Banding
- Conclusions

Why are Fast Fault Current Injection, Fault Ride Through and Banding related

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- The amount of fault current injected is a function of the volume of Generation at a specific location
- The retained voltage during the period of the fault is a function of the amount of reactive current injected - The lower the fault infeed, the lower the retained voltage seen across the system
- Fault ride performance is the ability of Generation to remain connected and stable under fault conditions. Its assessment is based on the retained voltage at the connection point which is directly related to the fault infeed.
- All Generation needs to play its part in supporting the System under fault conditions.
- A higher fault current infeed will enable a higher retained voltage to be specified as part of the fault ride through requirements.
- RfG specifies Generators are split into Bands. The fault ride through requirements are different between Synchronous and Asynchronous Plant with different parameters permitted between different bands

System Voltage profile under fault conditions – High / Low Synchronous Generation Background

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Figure 31
Current Network Effect of 3-phase Earth Fault at Walpole 400kV

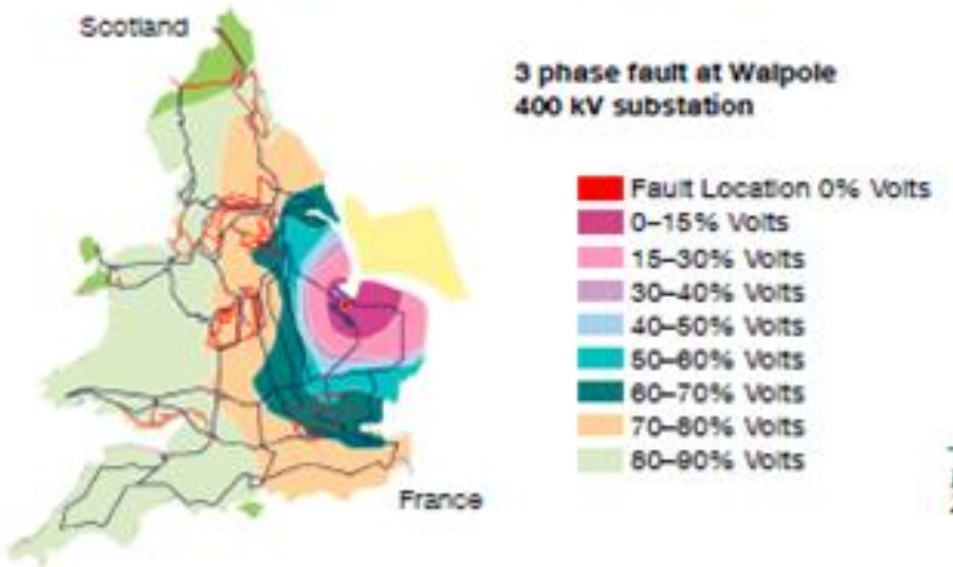
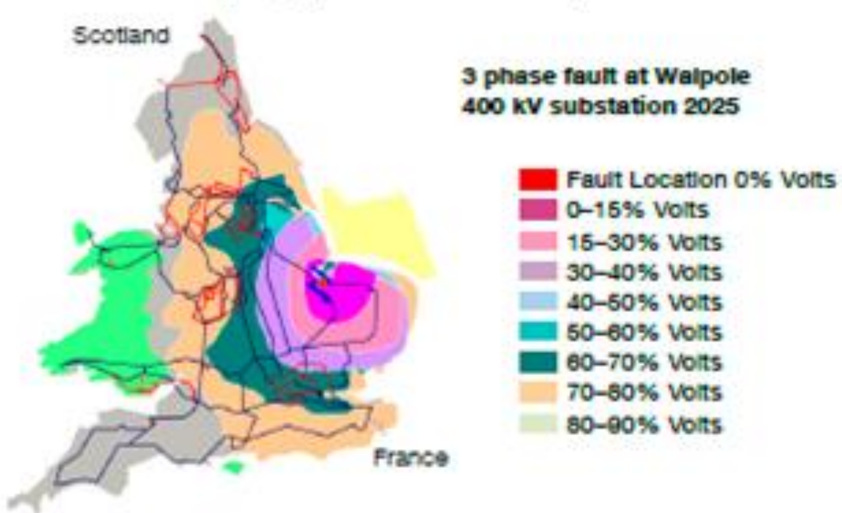


Figure 32
2025 Gone Green Effect of 3-phase Earth Fault at Walpole 400kV



The effect of connecting higher volumes of Converter based plant without FFCI

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- The Transmission System is changing - Large directly connected Synchronous Plant is rapidly being replaced by renewable technologies (eg wind, wave, solar and storage) – many of which utilise Converter based technologies
- Under fault conditions a Synchronous Generator will contribute 5 – 7pu current
- Converter based plant has a limited ability to supply fault current, (1 - 1.25pu current max),
- These effects significantly affect the design and operational characteristics of the System including the ability to maintain resilience and correctly detect and isolate a fault condition.
- At National Grid we want to promote the use of different generation technologies to ensure they grow whilst ensuring the safe, secure and efficient operation of the System.
- The System Operability Framework (SOF) published over the last few years have started to show the impacts on the System of high penetrations of converter based plant

High Converter Penetrations - Options

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- With current technology/models, the system can become unstable when more than 65% of generation is Non-Synchronous
- For the FES 2Degrees, Consumer Power and Slow Progression scenarios it is currently forecast, this level could be exceed by 9.2% -21,3% p.a. in 2023/24 and by 24.6% - 31.6% p.a.in 2026/27.

Key

No	Doesn't Resolve Issue
P	Potential
I	Improves
Yes	Resolves Issue

Solution	Estimated Cost	RoCoF	Sync Torque/Power (Voltage Stability/Ref)	Prevent Voltage Collapse	Prevent Sub-Sync Osc. / SG Compitable	Hi Freq Stability	RMS Modelling	Fault Level	Post Fault Over Volts	Harmonic & Imbalance	System Level Maturity	Notes
Constrain Asyncronous Generation	Hgh	I	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Proven	These technologies are or have the potential to be Grid Forming / Option 1
Syncronous Compensation	High	I	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Proven	
VSM	Medium	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	P	Modelled	
VSM0H	Low	No	Yes	Yes	No	P	P	P	Yes	P	Modelled	Has the potential to contribute but relies on the above Solutions
Synthetic Inertia	Medium	Yes	No	No	P	No	No	No	No	No	Modelled	
Other NG Projects	Low	Yes	P	Yes	No	No	No	P	P	No	Theoretical	

Timescale (Based on work by SOF team)	RoCoF	Sync Torque/Power (Voltage Stability/Ref)	Prevent Voltage Collapse	Prevent Sub-Sync Osc. / SG Compitable	Hi Freq Stability	RMS Modelling	Fault Level	Post Fault Over Volts	Harmonic & Imbalance
	Now	2019	2019	Now	2020	Now	Now	2025	2025

Fast Fault Current Injection – Power Park Modules and Converter based Plant

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- In the first quarter of 2017 extensive studies were run to understand the implications and control functions of converter based plant.
- These studies and results were presented to the GC0048 Workgroup in April 2017 available at:-
  - http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=8589940887
  - http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=8589940886
- These studies demonstrated the considerable variation in System behaviour as a result of changing the Converter control system. The following key conclusions were drawn from this work
  - The fault current needs to be injected in phase with the System during the fault otherwise both Transmission and Distribution performance is de-graded
  - Higher volumes of Generation connected to the Distribution System have a significant effect on the performance of the System even for Transmission System faults
  - If there is no fault current injection from the converter or it is injected out of phase with the system it places much more onerous requirements on the fault ride through requirements (U_{ret}).
  - Before 2021 there is still a reasonable contribution from Synchronous Generation connected to the System. Post 2021 these levels start to fall away very quickly

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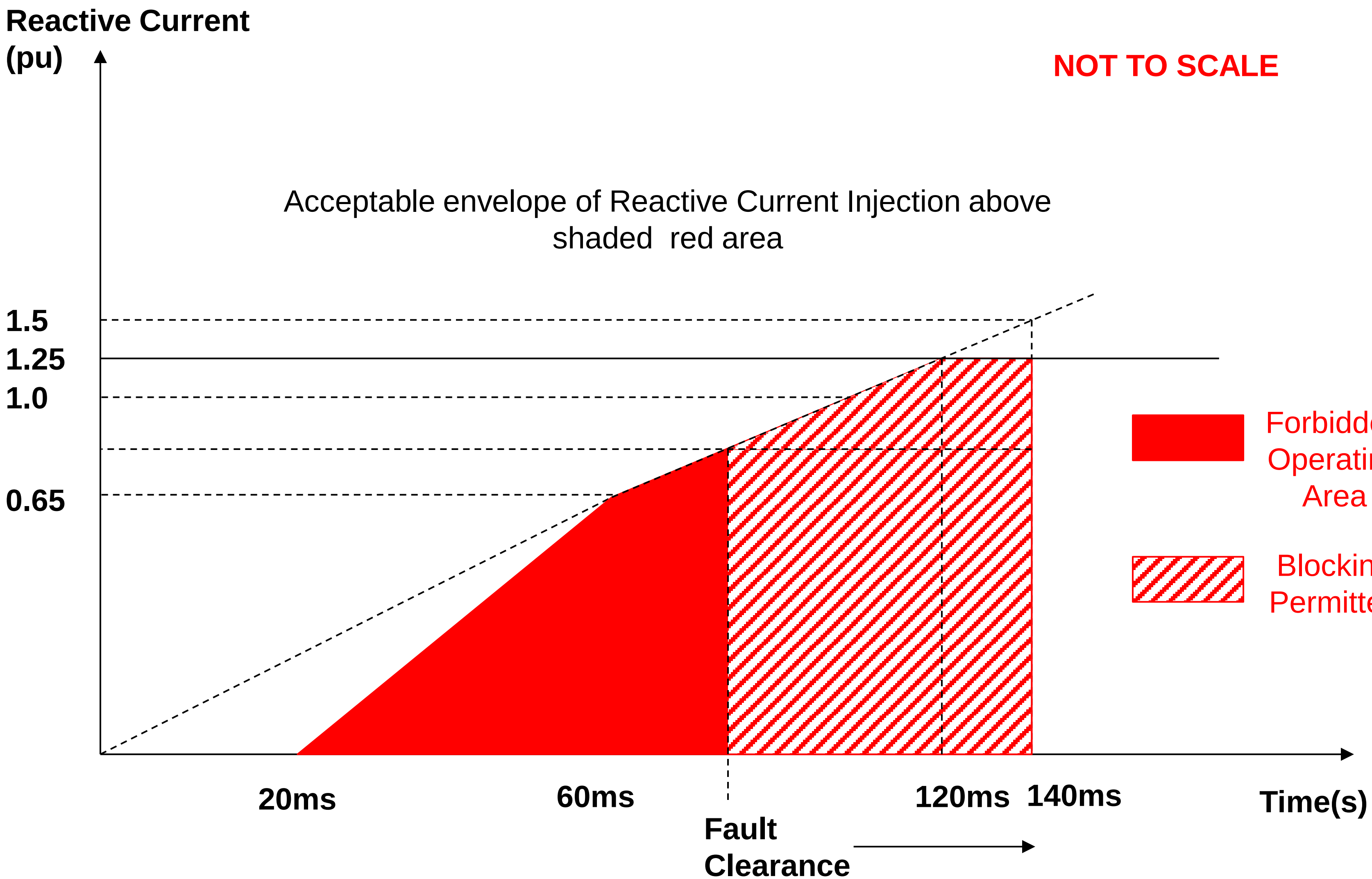
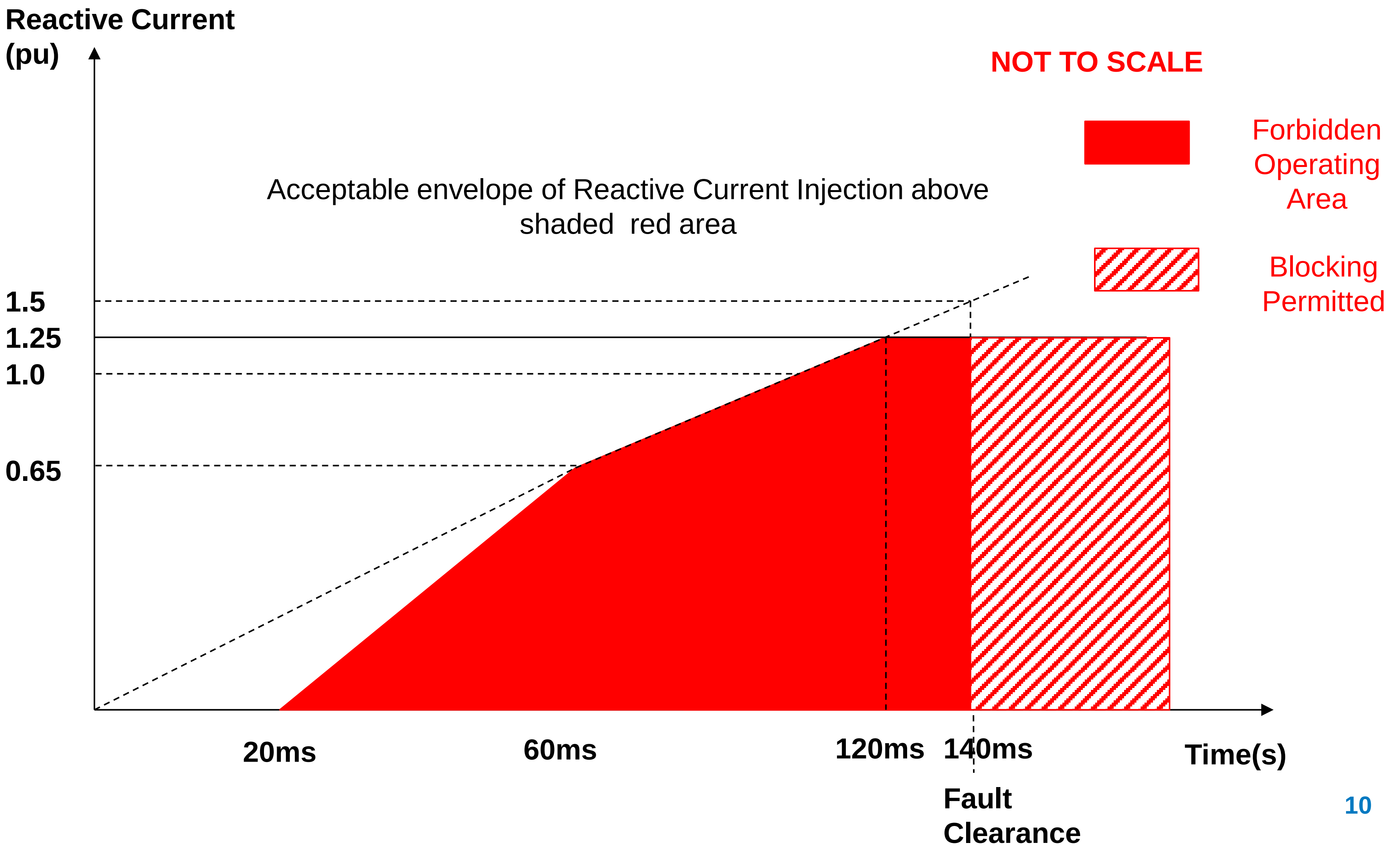
Proposals for Fast Fault Current Injection

- Two Options have been proposed
  - Option 1 – The Converter controller behaves in the same way as a synchronous machine (see attached presentation)
  - Option 2 – Conventional Converter – required to meet a minimum fault current injection requirement – option available only until 1 January 2021
- Option 1 is not new and similar technologies have been employed in the marine industry for several years in addition to a number of detailed studies
- Option 2 has also been employed previously as an option in areas of high converter penetration
- 2021 indicates FFCI (Option 1) as essential in studies presented to GC0048 in April
- The longer it takes for the technology to be implemented, the more onerous the requirements on new plant
- A European working group are investigating the implications of Grid Forming Converters

FFCI Option 2



FFCI Option 2



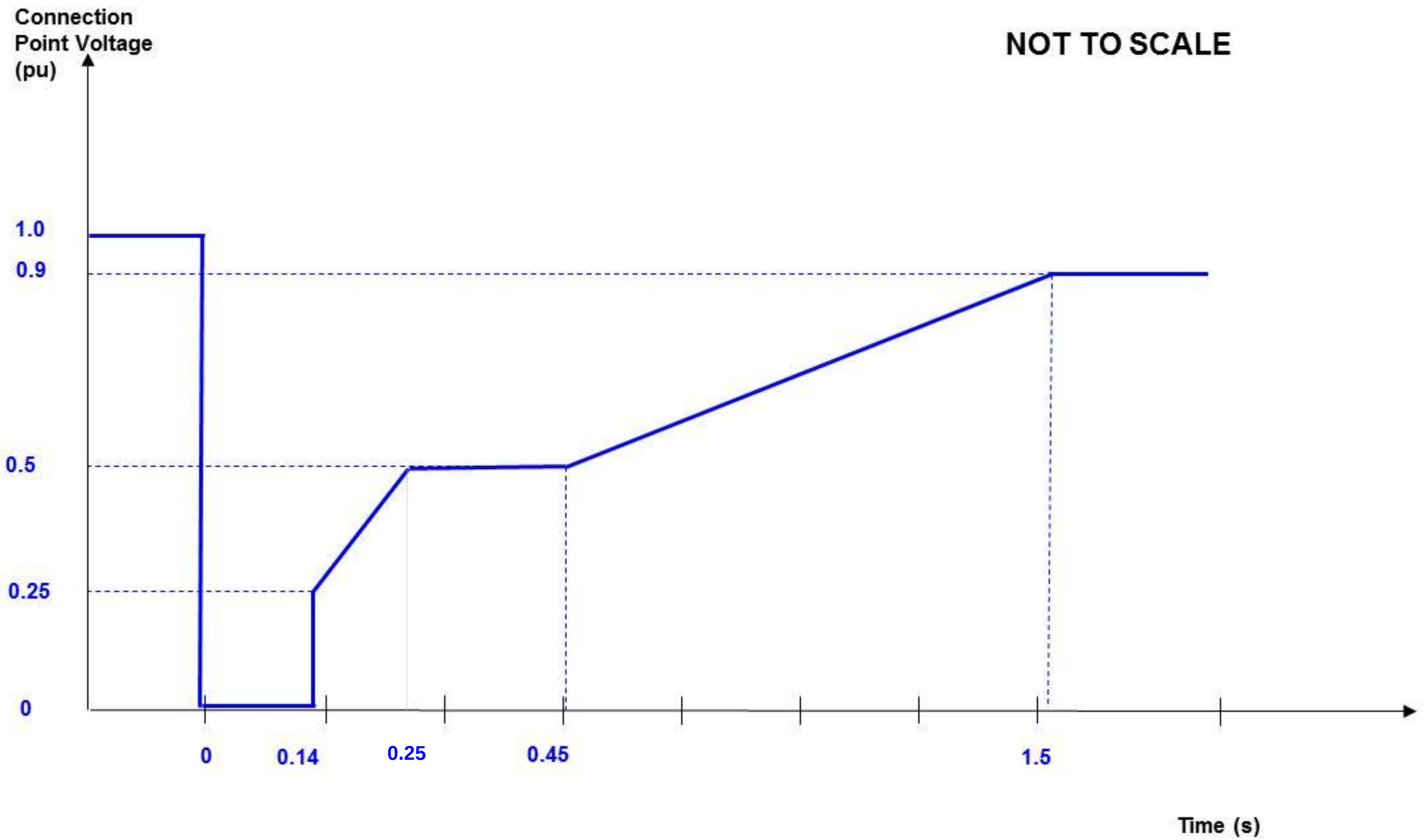
Fault Ride Through (1)

- The retained voltage at the connection point under faulted conditions is a function of the volume of fast fault current injected at the connection point
- For a solid three phase Transmission System fault, zero voltage will be observed at the point of the fault for the duration of the fault.
- For Type D plant connected at 110kV or above, the retained voltage (U_{ret}) would need to be set at zero volts (a mandated requirement under RfG)
- For Type B – D Embedded Plant (excluding Type B Synchronous) system studies (April 2017 GC0048 meeting) indicate requirements for a retained voltage (U_{ret}) of 10% if the assumptions on fast fault current injection are made.
- If Fast Fault Current Injection is not delivered in line with the proposals on slide 8, then the retained voltage (U_{ret}) delivered would need to be reduced to a value in the order of 5%.

Fault Ride Through (2)

- For Type B Synchronous Plant, the value of U_{ret} would need to be set to 30%. This is on the basis that small scale reciprocating plant (ie reciprocating gas and diesel engines) would struggle to meet a lower retained voltage for which there is no known technical solution. It is however recognised that Synchronous Generation is capable of supply high volumes of reactive current under fault conditions.
- The actual shape of the voltage against time curves have been documented and discussed at previous GC0048 Workgroup Meetings – The cost implications of these decisions are covered later in this presentation

GB Type D Voltage Against Time Curve



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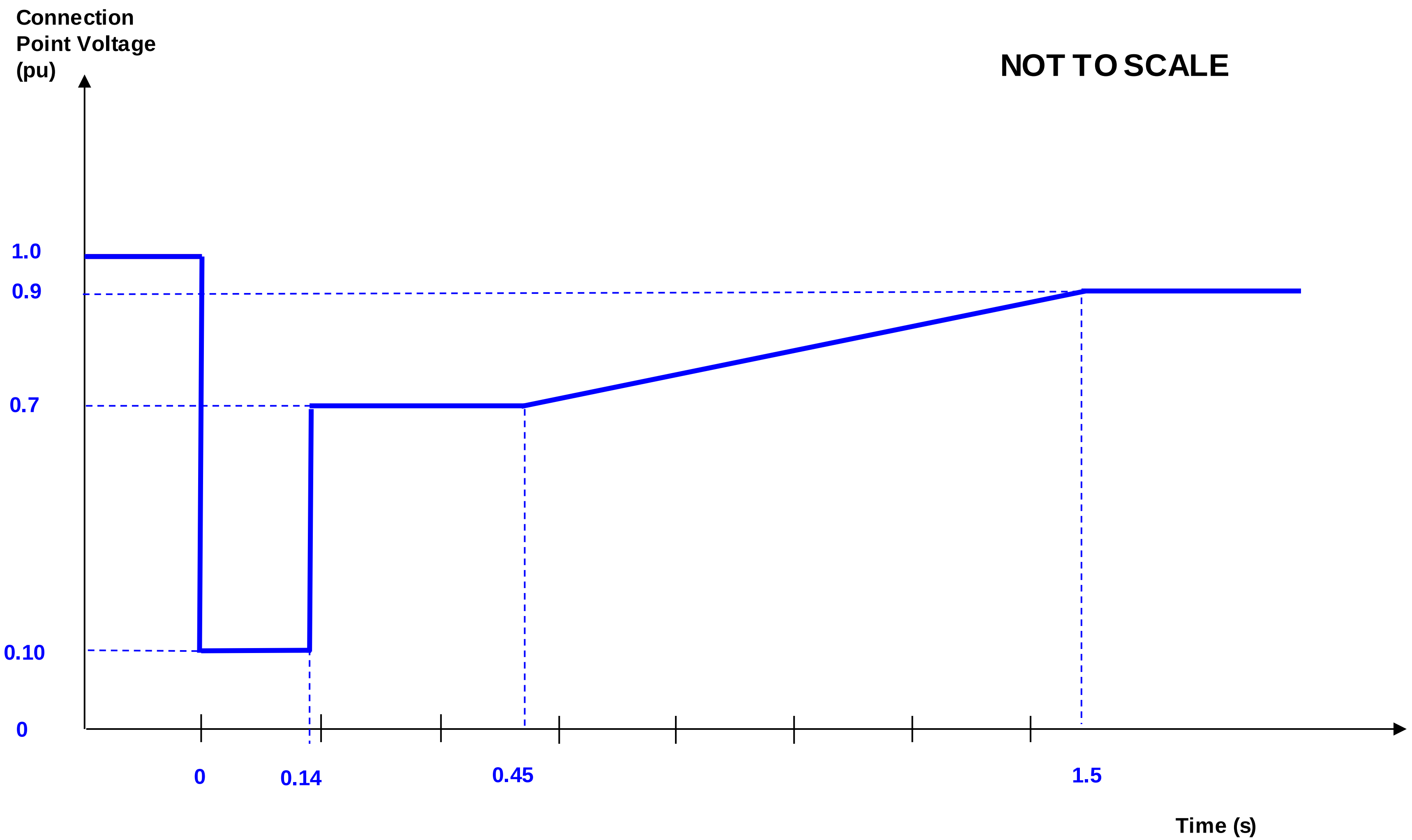
Voltage Against Time Parameters

Voltage parameters [pu]		Time parameters [seconds]	
U_{ret}	0	t_{clear}	0.14
U_{clear}	0.25	t_{rec1}	0.25
U_{rec1}	0.5	t_{rec2}	0.45
U_{rec2}	0.9	t_{rec3}	1.5

Table 7.1 – Fault Ride Through Capability of Synchronous Power Generating Modules

Suggested Voltage Against Time Profile – Type C and D



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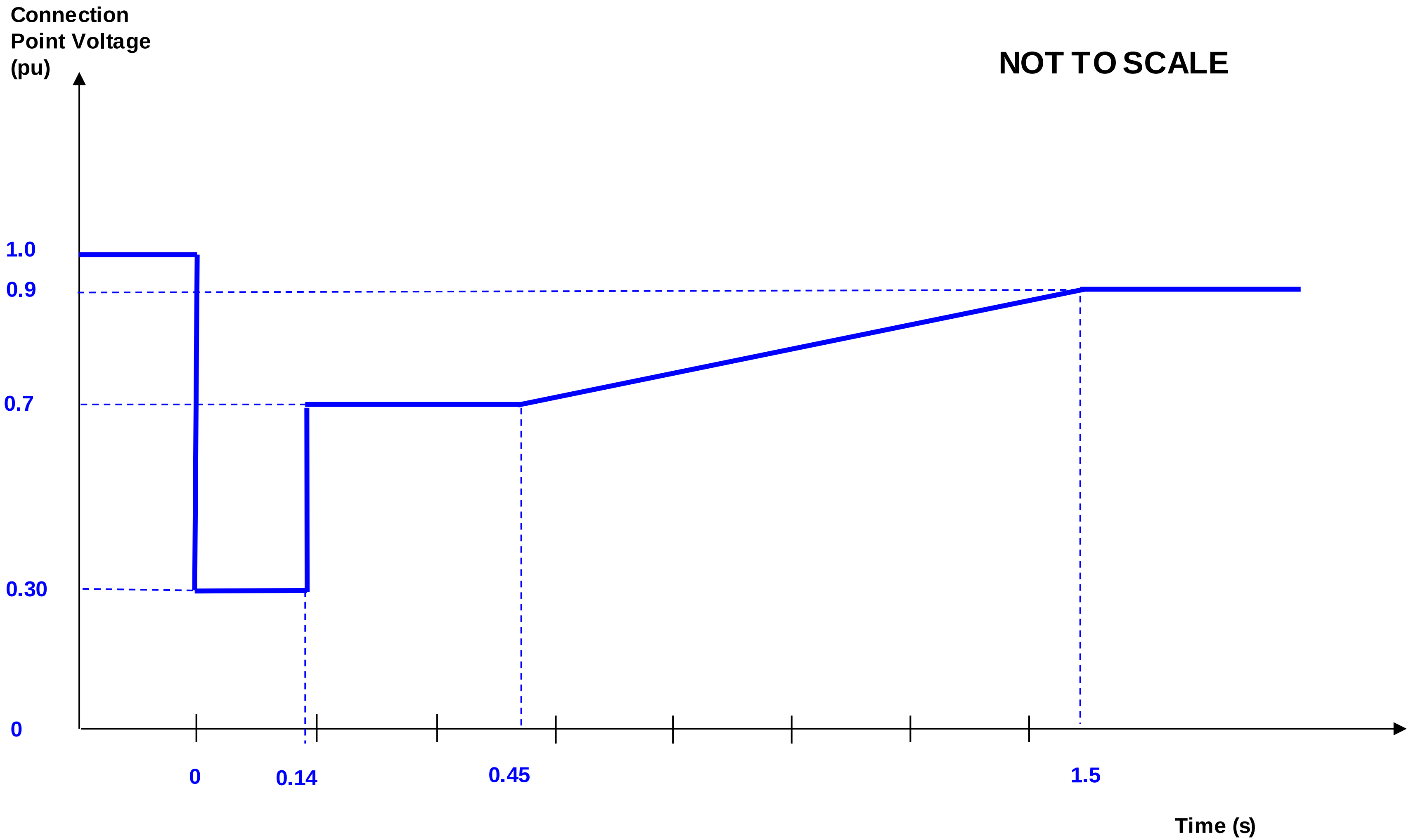
Voltage Against Time Parameter Ranges

Voltage parameters [pu]		Time parameters [seconds]	
U_{ret}	0.1	t_{clear}	0.14
U_{clear}	0.7	t_{rec1}	0.14
U_{rec1}	0.7	t_{rec2}	0.45
U_{rec2}	0.9	t_{rec3}	1.5

Table 3.1 – Fault Ride Through Capability of Synchronous Power Generating Modules

Type B Synchronous Power Generating Modules Connected <110kV

GB Voltage Against Time Profile – Type B



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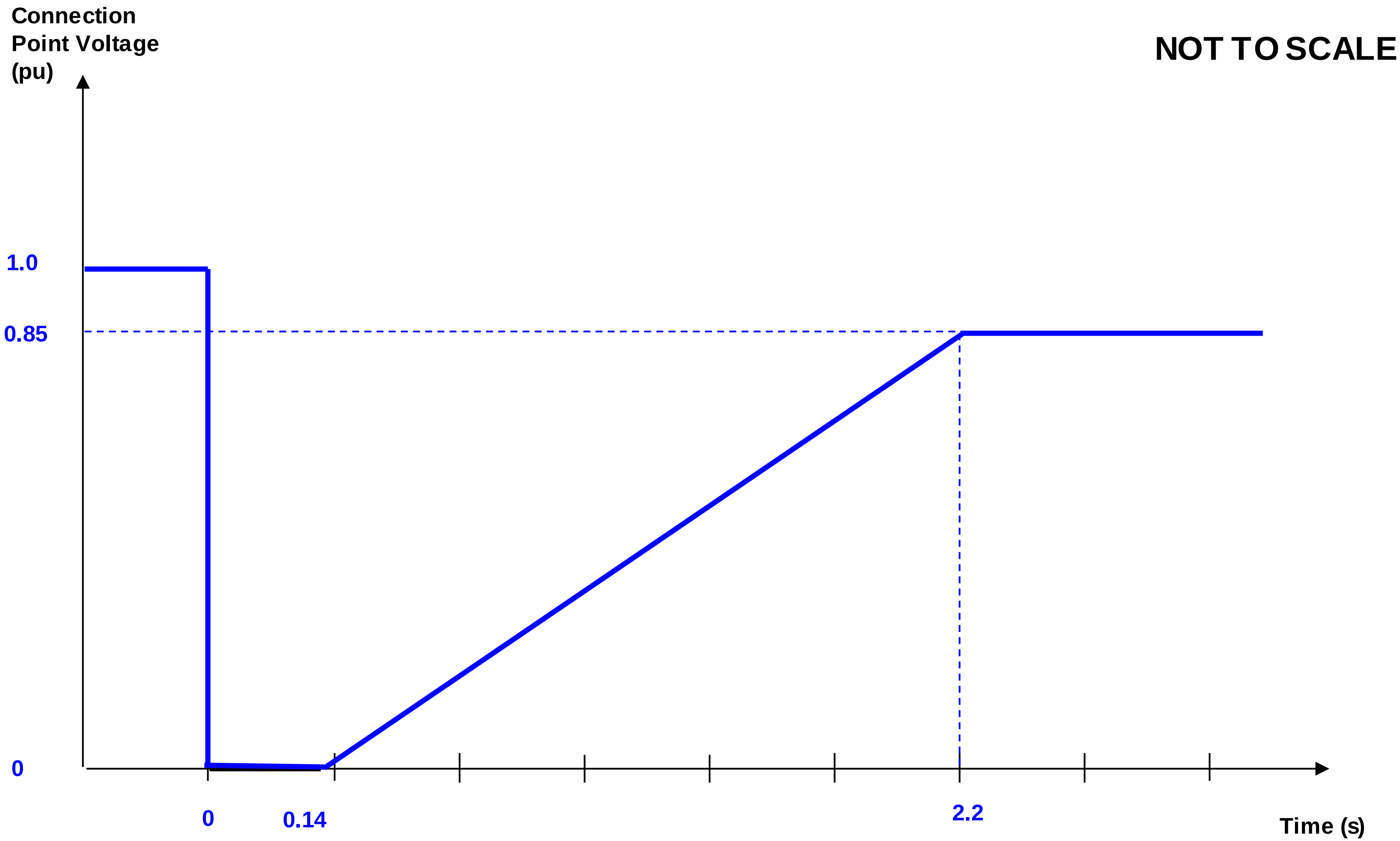
Voltage Against Time Parameter Ranges

Voltage parameters [pu]		Time parameters [seconds]	
U_{ret}	0.3	t_{clear}	0.14
U_{clear}	0.7	t_{rec1}	0.14
U_{rec1}	0.7	t_{rec2}	0.45
U_{rec2}	0.9	t_{rec3}	1.5

Table 3.1 – Fault Ride Through Capability of Synchronous Power Generating Modules

Type D Power Park Modules connected ≥110kV

GB Voltage Against Time Profile – Type D



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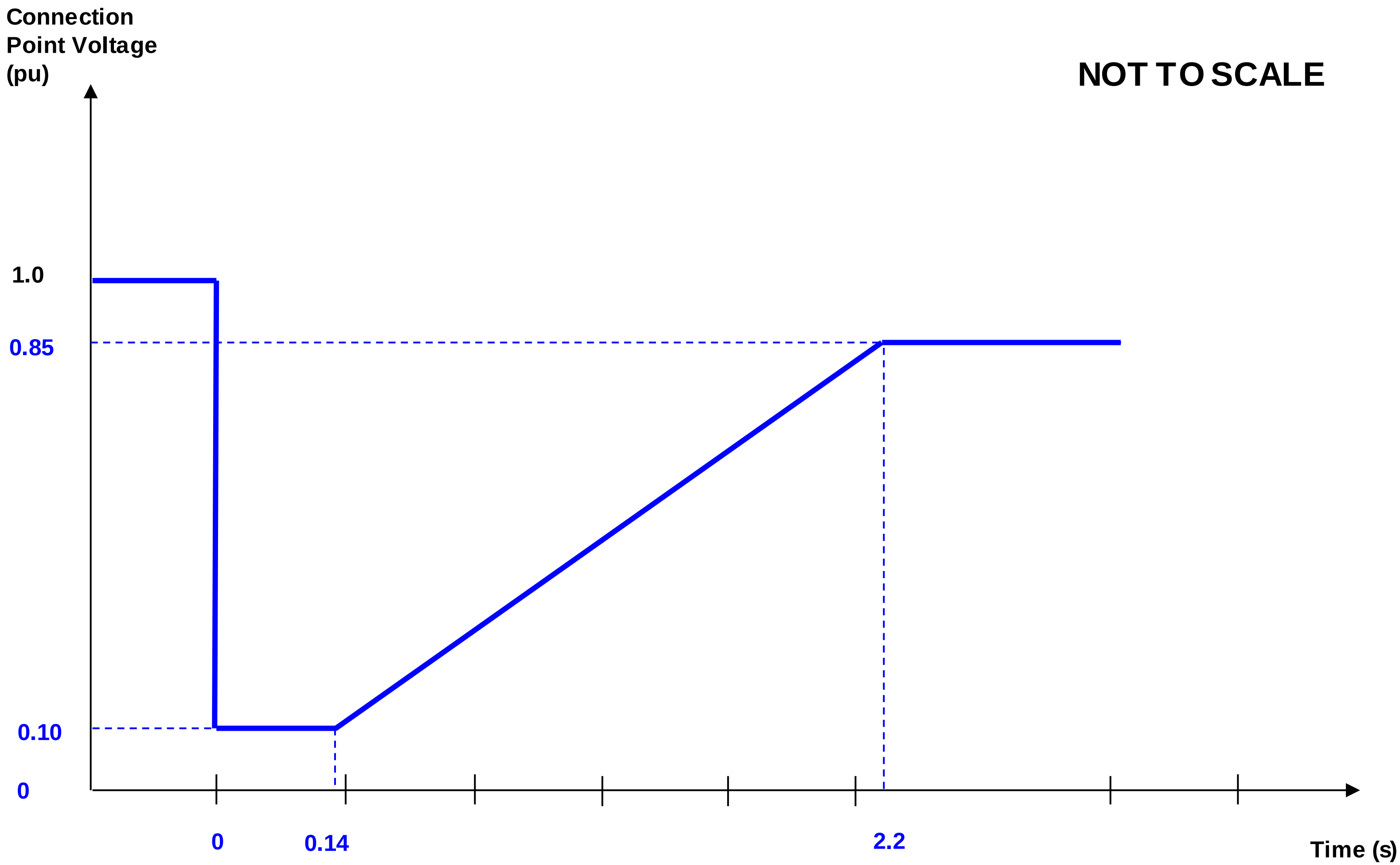
Voltage Against Time Parameters

Voltage parameters [pu]		Time parameters [seconds]	
U_{ret}	0	t_{clear}	0.14
U_{clear}	0	t_{rec1}	0.14
U_{rec1}	0	t_{rec2}	0.14
U_{rec2}	0.85	t_{rec3}	2.2

Table 7.2 – Fault Ride Through Capability of Power Park Modules

Type B, C and D Power Park Modules connected <110kV

GB Voltage Against Time Profile - Type B, C and D



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Voltage Against Time Parameters

Voltage parameters [pu]		Time parameters [seconds]	
U_{ret}	0.1	t_{clear}	0.14
U_{clear}	0.1	t_{rec1}	0.14
U_{rec1}	0.1	t_{rec2}	0.14
U_{rec2}	0.85	t_{rec3}	2.2

Table 7.2 – Fault Ride Through Capability of Power Park Modules

Banding Introduction

- Three banding options (high/mid/low) were discussed during GC0048
- Under RfG, NGET has to propose a set of Banding Thresholds for the GB Synchronous Area
- The banding values have a close relationship with fast fault current injection and fault ride through requirements
- ***Fast Fault Current Injection and Fault Ride Through apply to Type B and above.***

RfG Requirements / Band At A Glance

Technical Requirements	Type A	Type B	Type C	Type D
Operation across range of frequencies	•	•	•	•
Rate of change of System Frequency (ROCOF)	•	•	•	•
Limited Frequency Sensitive Mode Over Frequency (LFSM-O)	•	•	•	•
Output Power with falling Frequency	•	•	•	•
Logic Interface (input port) to cease active power production	•	•	•	•
Conditions for automatic reconnection	•	•	•	•
Operation across range of frequencies	•	•	•	•
Ability to reduce Active Power on instruction		•	•	•
Fault Ride Through and Fast Fault Current Injection		•	•	•
Conditions for automatic reconnection following disconnection		•	•	•
Protection and Control		•	•	•
Operational Metering		•	•	•
Reactive Capability		•	•	•
Active Power Controlability			•	•
Frequency Response including LFSM-U			•	•
Monitoring			•	•
Robustness			•	•
System Restoration / Black Start			•	•
Simulation Models			•	•
Rates of Change of Active Power			•	•
Earthing			•	•
Enhanced Reactive Capability and control			•	•
Voltage Ranges				•
Enhanced Fault Ride Through				•
Synchronisation				•
Excitation Performance				•

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National Grid Proposal for GB Banding

Band	MW Threshold/Connection Voltage
Band A	800W – 0.99MW and connected at or below 110kV
Band B	1MW – 9.99MW and connected at or below 110KV
Band C	10MW – 49.99MW and connected at or below 110kV
Band D	50MW plus or connected at 110kV or above

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Banding - Implications

- For Fault Ride Through, the value of U_{ret} proposed for all Type B – D plant connected below 110kV (excluding Type B Synchronous Plant) has been set to 10%.
  - This has been based on System Studies and assumes a minimum fault infeed as per the FFCI proposals
- For Type B Synchronous Plant the value of U_{ret} has been set to 30%. Note that they will be capable of supplying a reasonable degree of fault current
- Guidance from ENTSO-E has indicated that the voltage against time parameters must be defined for each Band

Banding - Comparison with Proposals of other EU TSOs

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Country	Band A*	Band B*	Band C*	Band D'
Belgium	800W – 250kW	0.25MW – 25MW	25MW – 75MW	75MW plus
France	800W – 1MW	1MW – 18MW	18MW – 36 MW	36MW plus
Netherlands	800W – 1MW	1MW – 50MW	50MW – 60MW	60MW plus
German TSO's	800W – 135kW	0.135MW – 36MW	36 MW – 45MW	45MW plus
Spain	800W – 100kW	0.1 MW – 5MW	5MW – 50MW	50MW plus
Ireland	800W – 100kW	0.1MW – 5MW	5MW – 10MW	10MW plus
GB	800W – 0.99MW	1MW – 9.99MW	10MW – 49.9MW	50MW plus

* Applicable MW threshold and connected below 110kV

' Applicable MW threshold or connected at or above 110kV

Justification for NGET's GC0100 Proposals

- The intention of the EU proposals is based on the principles of non-discrimination and transparency as well as on the principles of optimisation between the highest overall efficiency and lowest total cost for all involved parties.
- Through Stakeholder engagement we have understood technical limitations in setting retained voltage at 30% for Band B Synchronous Reciprocating Plant)
- If Converter based plant does supply reactive current in line with the FFCI proposals, the study run in the South West has indicated that approximately 550MW of Embedded Generation would see voltage drops of below 10% and hence trip. This would equate to approximately £240million/ annum in additional reserve costs alone.
- Without the assumed level of FFC I, lower values of U_{ret} would be required (0.05pu rather than 0.1pu) and it would also place more Band B Synchronous generation at risk from tripping at an estimated cost of £9.2million/annum in reserve costs alone.
- The Studies run in the South West are believed to be representative of the wider System – see next slide

How the South West compares to other areas of GB

Area		GC048 study			Future Of Energy documents					
		SCL studied 2025 (kA)	DG installed 2025 (MW)	DG studied 2025 (MW)	FES2025 max DG output (MW)	FES2025 min DG output (MW)	SOF regional SCL min (kA)	SOF regional SCL 95% confidencemin (kA)	SOF regional SCL 95% confidence max (kA)	SOF regional SCL max (kA)
1	North Scotland	N/A	N/A	N/A	1839.5	1167.6	6.8	11.9	16.5	18.6
2	South Scotland	N/A	N/A	N/A	2941.8	2024.4	9.5	13.1	20	21
3	North East England	N/A	N/A	N/A	1360.6	885.4	10.8	14.4	29.3	34.1
4	North West and West Midlands	N/A	N/A	N/A	3338.1	1990.1	0.7	5.7	21.1	22
5	East Midlands	N/A	N/A	N/A	3540.8	2029.3	2.7	7.1	24.4	28.4
6	North Wales	N/A	N/A	N/A	740.1	594.3	13.3	21.6	36.1	38
7	South Wales and West england	N/A	N/A	N/A	3677.3	2300.5	6.4	9.8	26.2	30.4
8	South West England	16.3	2522.4	2411	**3213**	**1999.7**	**2.4**	**7.3**	**22.1**	**25.9**
9	East England	N/A	N/A	N/A	3934.5	2543.1	9.1	17.4	41.5	45.6
10	Greater London	N/A	N/A	N/A	1716	1104.4	6.2	14.2	32.4	35.7
11	South East England	23.95345696	N/A	N/A	2059	1268.2	7.6	15.1	27.9	31.7

Justification for NGET's GC0100 Proposals

- Larger Synchronous Generators, eg those derived from steam, gas or hydro turbines are not believed to suffer from these issues
- A questionnaire released to GB Stakeholders in 2016 revealed there would be no additional significant costs from a technical perspective if the lower threshold was applied.
- RfG enforces a consistent banding requirement across GB. The proposed Banding applies capabilities currently demonstrated in the North of Scotland across the whole GB System
- The majority of European TSO's are proposing Banding lower than the maximum permitted under RfG
- The Continental Power System is of the order of 10 times larger than the GB System

Conclusions
FFCI / Fault Ride Through

- Based on the study work and analysis completed National Grid recommend the FFCI issues proposed. It is believed that the adoption of this option will result in a saving of approximately £240million / annum in reserve costs alone not including the wider significant benefits of contribution to synchronising torque, fault infeed and inertia.
- The Fault Ride Through voltage against time curves are recommended on the basis of minimum system need. These are based on the assumption of the delivery of FFCI. Without the proposed level of FFC I, lower values of U_{ret} in FRT would be required (0.05pu rather than 0.1pu)
- These measures would not be retrospective and would apply to new plant going forward.

Conclusions
Banding

nationalgrid

- National Grid has lodged its proposal for the GB banding (slide 24)
  - The relationship between FFCI / Fault Ride Through and cost has been demonstrated
  - Without FFCI as proposed we will need to lower the value of U_{ret} (from 0.1pu to 0.05pu). There is also a cost of tripping synchronous generation in a higher band (10MW – 50MW) which would result in reserve costs alone of £9 million / annum.
  - Following public Stakeholder discussions U_{ret} of 0.3pu for Band B Synchronous Plant is proposed
  - The costs to which Generators are exposed for these thresholds was identified to be negligible following the responses to the Stakeholder questionnaire held in 2016, excluding market costs (ie BM participation costs).
  - Parity with European TSO proposals, particularly with regard to cross boarder trade
  - The proposals would apply the same technical requirements across the whole of GB
  - A Band B/C Threshold of 10MW would provide a greater proportion of Generation being capable of contributing to frequency response which drives competition and reduces net cost
  - System Operators will need to continue to operate a safe, secure and economic System against a rapidly changing Generation background
  - RFG Mandates TSO's to propose banding thresholds

Annex 6 - Fast Fault Current Injection supporting documents

Outline of the RfG FFCI and FRT proposals:

GC0048 – FFCI FRT Reading.pdf

Background on the Fast Fault Current Injection requirement:

Background on Fast Fault Current Injectio

FFCI Option 1 Concepts.pdf

FFCI Study Presentation_GC0048

Fast Fault Current Injection: GB context of case study:

Fast Fault Current Injection C...

Annex 7 – Industry Responses to GC0048 consultation on potential GB banding levels

GC0048 Banding Consultation Responses.zip