Modification	At what stage is this document in the process?
DCRP/MO/19/05 Report to Authority DCode EREC G99 Fast Fault Current Injection Modifications Modifications to The Distribution Code and EREC G99 of the requirements for Fast Fault Current Injection.	01 Modification 02 DCRP report 03 Public Consultation 04 Final Modification Report

The purpose of this document is to assist the Authority in its decision to implement the proposed modification to Engineering Recommendations G99. The proposed modification aims to clarify (but not change) the requirements for fast fault current injection with which Power Park Modules of Type B, C and D need to comply with.

Date of publication: 20 June 2019

Recommendation

The DNOs recommend that the proposed modifications are made to Engineering Recommendation G99 and the Distribution Code.

✔	The DNOs and DCRP recommend that this modification should be: Submitted to the Authority for approval
!	High Impact: None
!	Medium Impact: None
!	Low Impact: Manufacturers and developers of embedded power park modules

Contents

Timetable

Workgroup Report presented to Panel	9 April 2019
Draft Modification Report issued for consultation	12 April 2019
Consultation Closed	10 May 2019
Final Modification Report available for Panel	5 June 2019
Final Modification Report submitted to Authority	20 June 2019

Any questions?

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Purpose of the Modification

Ofgem approved the implementation of the EU Network Code "Requirements for Generators" (RfG) on 15 May 2018 (with compliance required from 27 April 2019). The implementation consisted of parallel changes to the Grid and Distribution Codes, and the introduction of ERECs G98 and G99.

The modification which was implemented in GC0100 (EU Connection Codes GB Implementation Mod 1) recast the long-standing Grid Code fast fault current injection (FFCI) requirements in a way that was intended to be phrased so as to be compatible with the Requirements for Generators (RfG). Identical wording was used in both the Grid Code and EREC G99 to describe the FFCI requirements. However, the wording chosen by the GC01000 workgroup has proven to be open to misinterpretation and has induced some confusion amongst a number of stakeholders, particularly manufacturers.

Manufacturers of Power Park Modules need clarity on the FFCI requirements so that then can ensure compliance at the point of manufacture. It is not possible to test for compliance with the FFCI requirements on site, so it is crucially important that the requirements are specified with complete clarity and freedom from ambiguity.

Details of the Proposal

Shortly after the GC0100 proposal had been submitted to the Authority, a number of comments were received in relation to the clarity over the interpretation of fast fault current injection. These mainly related to the plant rating and how the injected current may vary in phase and magnitude with respect to both voltage deviation and time.

Following identification of this issue, the Grid Code Review Panel and the Distribution Code Review Panel agreed to jointly review the issue and to look for a solution that would resolve the issues for both transmission and distribution connected generation. This was agreed at the Distribution Code Review Panel meeting on 5 April 2018 and the Grid Code Review Panel meeting of 26 April 2018.

The joint GC0111 working group (WG) convened on four occasions between July 2018 and February 2019 to discuss how the legal text could be amended to make the intention fully clear and avoid ambiguity in interpretation.

The full details of the proposals and workgroup discussions are included in National Grid Electricity System Operator's GC0111 consultation document:

https://www.nationalgrideso.com/codes/grid-code/modifications/gc0111-fast-fault-current-injection-specification-text

The proposals were consulted upon by both the Grid Code and Distribution Code review panels (05 April to 08 May for the Grid Code modifications and 12 April 2019 to 03 May 2019 for the EREC G99 modifications).

Three responses were received from stakeholders. One response was simply fully supportive. The other two responses suggested a number of minor wording changes. The editorial ones have been accepted, but there are a few which suggest changes that do not seem appropriate given the careful development of the text in the joint working group. The full details of these responses is included in Appendix 1.

The proposals and workgroup discussions from the above consultation document is copied here as Appendix 2.

The proposed revised formulation of the FFCI requirements in G99 have been drafted alongside the equivalent Grid Code text and are essentially identical, accepting the slightly different drafting context of the Grid Code and G99. The proposed amendments to G99 are included here as Appendix 3.

Note that GC0111 is being progressed by NGESO under the self-governance provisions of the Transmission Licence so will not be submitted to Ofgem for approval.

Impacts on Total System and the DNOs' Systems

There is no impact on the Total System nor on DNOs' systems. Implementing these proposed modifications should remove ambiguity and ease the compliance process for both manufacturers and DNOs.

Impacts on the Users of DNOs' Systems

There are no new impacts on Users of DNOs' systems.

Assessment against Distribution Code Objectives

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

The proposal has a positive impact on this objective by reducing uncertainty and ambiguity.

(ii) To facilitate competition in the generation and supply of electricity

The proposal has a positive impact on this objective as it makes it more straightforward for new generation to demonstrate compliance.

(iii) Efficiently discharge the obligations imposed upon DNOs by the Distribution Licence and comply with the Regulation (where Regulation has the meaning defined in the Distribution Licence) and any relevant legally binding decision of the European Commission and/or Agency for the Co-operation of Energy Regulators.

The proposal has a positive impact on this objective by reducing uncertainty and ambiguity.

(iv) Promote efficiency in the implementation and administration of the Distribution Code.

The proposal has a neutral impact on this objective.

Impact on other Industry documents

There are no impacts on other industry documents.

Environmental Impact Assessment

There are no environmental impacts associated with this proposed modification.

Distribution Code Review Panel Recommendation

The responses to the consultation were discussed at the DCRP meeting on 06 June 2019 and the Panel agreed that the changes should be submitted to Ofgem.

Recommendation

The Licenced Distribution Network Operators and the DCRP recommend that this modification report should;

- be submitted to the Authority for approval; and
- subject to the agreement of the Authority the modification should be implemented from the date the revised Distribution Code and associated documents are published. This date is recommended as 22 July 2018 or such other date as the Authority directs.

Appendices

Appendix 1 – Responses to the consultation

Appendix 2 – Work Group Discussions

Appendix 3 – Legal text for G99

Appendix 1 – Responses to the Consultation

Northern Powergrid

Scottish Power Renewables

SMA Ltd

Appendix 2 – Workgroup Proposals and discussions:

This text is a copy of sections 3 and 4 of the GCRP Code Administrator's Consultation on GC0111, ie the commentary on the joint workgroup's discussions. The full report can be found here: https://www.nationalgrideso.com/codes/grid-code/modifications/gc0111-fast-fault-current-injection-specification-text

Existing Requirements and Issues

The requirements for FFCI as specified in [Grid Code] ECC 6.3.16.1 will need to be updated following agreement in the Workgroup as to the precise requirements that need to be complied with.

In GC0100 EU Connection Codes GB Implementation Mod 1 new requirements were introduced into the Grid Code in respect of fast fault current injection. These requirements apply only to Power Park Modules. Prior to the introduction of RfG (implemented on 16 May 2018), there was a loose requirement for fast fault current injection although this simply stated that each Power Park Module shall generate maximum reactive current without exceeding the transient rating of the Power Park Module and/or any constituent Power Park Unit. There was no requirement until G0100 for distribution connected Power Park Modules to provide FFCI.

Alternatively, RfG (Article 21(3)) specifies a much more detailed requirement with respect to the reactive current injection requirements. These issues and the approach to implementation were covered in GC0100 EU Connection Codes GB Implementation Mod 1.

Shortly after the GC0100 Code Administrator Consultation, and after the proposals had been submitted to the Authority, a number of comments were received in relation to the clarity over the interpretation of fast fault current injection. These mainly related to the plant rating, how the injected current may vary in phase and magnitude with respect to both voltage deviation and time.

Plant Rating and Upper Limitations on Reactive Current Injection

The first meeting was held in July 2018 to articulate the scope of the problem and defined that there would be no requirement for the rating of the Power Park Module to be exceeded. The slides for this first meeting are attached in Annex 2A [of the GCRP Code Administrator Consultation]. Of importance during this meeting was the introduction of a concept to specify that the rating of the Power Park Module was not expected to be exceeded.

Figure 1.0 below shows a typical wind farm comprising one Power Park Module. Under a faulted condition where the voltage at the connection point falls to zero the intention would be for the Power Park Module to supply full reactive current without exceeding the rating of the Power Park Module or HVDC System.

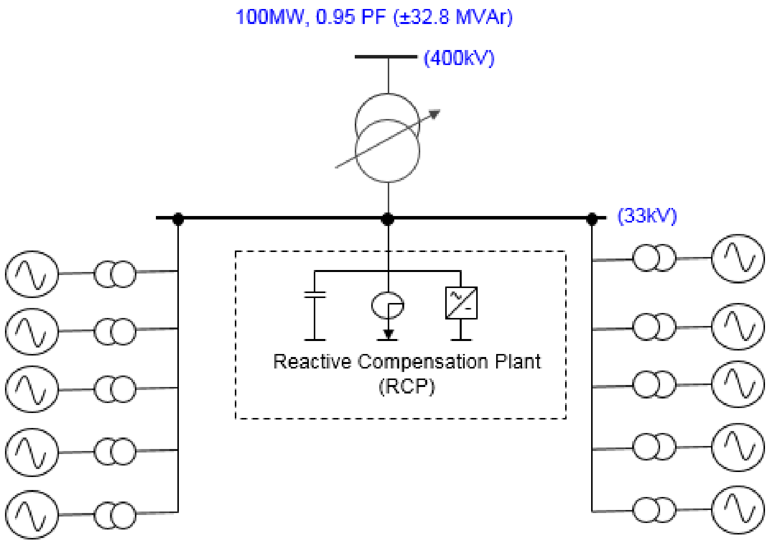

Figure 1.0

The rating of the Power Park Module or HVDC System is calculated on the basis of the rated MW output at maximum Reactive Power Output. Taking the example of the wind farm shown in Figure 1.0, if the Rated MW output was 100MW to meet the ECC.6.3.2.4 reactive capability requirement of 0.95 Power Factor lead to 0.95 Power Factor lag, this requires a reactive capability of ±32.9MVAr and hence the rating of the Power Park Module becomes 105.3 MVA (ie $\sqrt{(100^2 + 32.9^2)}$ or 1.0pu on Rated MVA (ie 105.3/105.3).

Under a faulted condition, the reduction in system voltage will result in a consequential increase in reactive current to the point where at zero voltage at the connection point the full reactive current injection. As noted above, the reactive current injection would not be required to exceed the rating of the Power Park Module or HVDC System.

Figure 2.0 below shows how the real and reactive current varies. The locus (ie the circle) being the rating of the Power Park Module or HVDC Converter which in this example is 1.0pu on the MVA base of the Power Park Module or 105MVA.

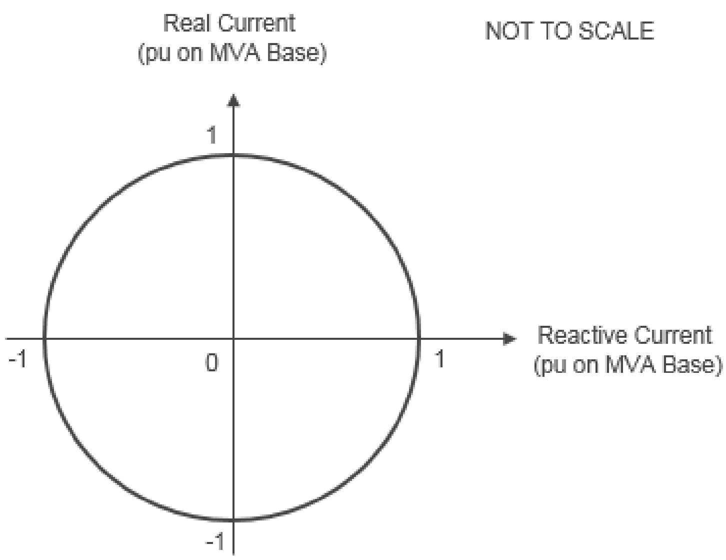

Figure 2.0

In the event of a fault, Figure 3.0 shows the blue vector and blue dashed vector moving towards the x axis (ie an increase in reactive current supply as compared to the red and green vector which forms the boundary between when the Power Park Module is operating in a steady state condition (ie operation between 0.95 lead and 0.95 lag).

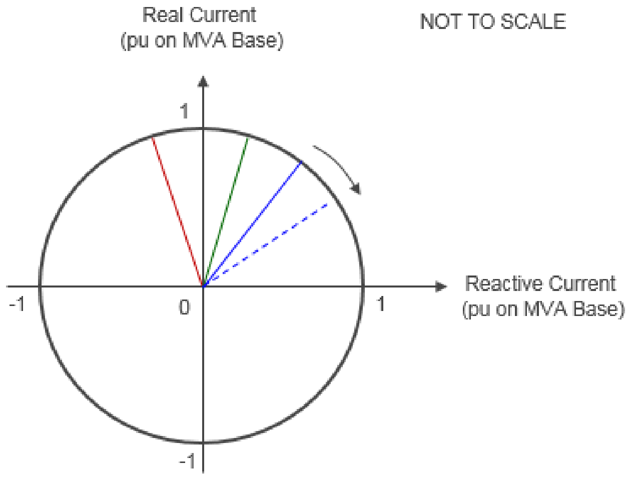

Figure 3.0

Whilst the current version of ECC.6.3.16 does not make the upper limitations on requirements clear, this has now been covered in more detail in the proposed new sections ECC.6.3.16.1.7 based on the explanation above.

<u>Required Reactive Current Injection in Response to Voltage Variation and Time</u>

The second deficiency is that in the current version of ECC [and G99] it is not clear how the reactive current should vary with depressed voltage.

At its highest level, National Grid has a number of fundamental requirements when it comes to ensuring the robustness of the system under fault conditions. These are summarised as follows:-

Criteria	**Requirement**
Fault Ride Through	Power Generating Modules to remain connected and stable for up to 140ms in duration for both balanced and unbalanced faults which would include a close up solid three phase short circuit adjacent to the Connection Point
	Power Generating Modules to remain connected and stable for any balanced fault in excess of 140ms so long as the retained voltage is above the heavy black line specified in ECC.6.3.15.9.

Fast Fault Current Injection	Reactive current injection required each time the voltage falls below the nominal voltage levels in ECC.6.1.4. The reactive current injected should progressive increase as the voltage drop increases with any residual current being supplied as active current. There should be a smooth control between steady state operation and faulted conditions

These criteria are important. The requirements for fault ride through are well documented in numerous texts and the reader is encouraged not only to refer to the material included in the appendices within this report but also Grid Code Consultation GC0100 which is available from the link below.

https://www.nationalgrideso.com/sites/eso/files/documents/Final%20Workgroup%20consultation_0.pdf

In summary when a generator is exposed to a close up solid three phase short circuit fault there is a requirement to inject maximum reactive current so as to maintain System voltage and for longer duration voltage dips there is a requirement for a contribution of reactive current with the residual to be supplied as Active Current so as to contribute to Active Power, this being important criteria for the support of system frequency in the event of a voltage dip.

Initial Consideration of the German Model for Reactive Current Injection

As an initial starting point, the German model was first considered as shown in Figure 4.0 where the injected reactive current is a function of the voltage.

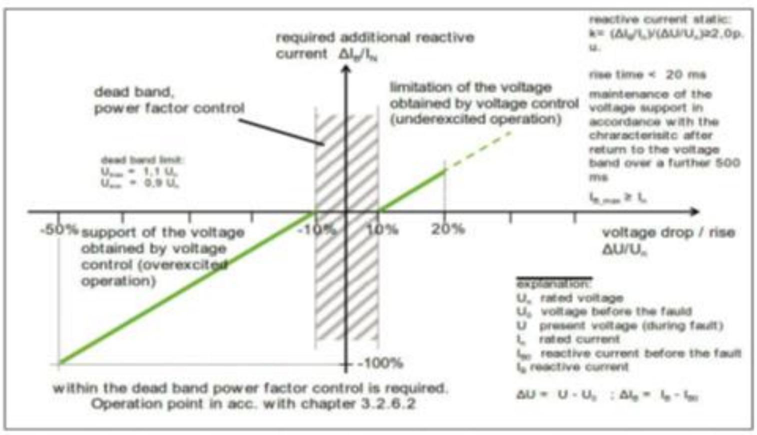

Figure 7 The principle of power factor control in normal operation and voltage support in case of disturbances

Figure 4.0

This interpretation uses the following formula's

$I_R =$ $\Delta V.k + I_{Prefault}$

I_R – The Reactive Current injected in pu during the fault in pu. This cannot exceed 1.0pu on the MVA Rating

$V =$ $V_{prefault} - V_{deadband} - V_{retained}$

$V_{prefault}$ – Is the Prefault Positive Phase Sequence voltage in pu

$V_{deadband}$ - Is the deadband either side of nominal voltage set at 0.1pu

$V_{retained}$ – Is the positive sequence voltage at the Grid Entry Point or User System Entry Point under faulted conditions

K – Is the voltage gain factor set to 1

$I_{prefault}$ – Is the prefault reactive current in pu.

These concepts were further explored and presented to the workgroup in September 2018, which resulted in the following revised voltage / reactive current diagram shown in Figure 5.0.

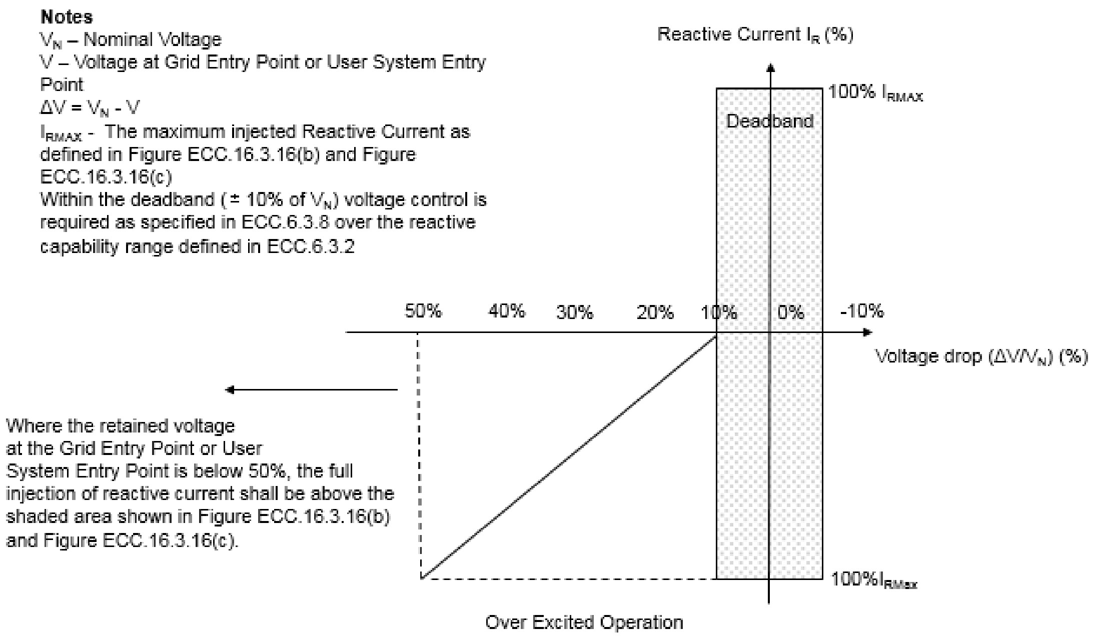

Figure 5.0

In addition, corresponding legal text was also developed. At this stage, a number of Workgroup members expressed concern over the behaviour of Power Park Modules and HVDC Systems during unbalanced faults and that the performance of plant can vary quite significantly between full converter based plant or DFIG derived equipment. A number of concerns were also expressed with regard to operation between steady state and under faulted conditions.

At this stage two options were suggested by the workgroup. One was to consider the approach adopted as discussed in September, another was to adopt an approach similar to that proposed in EN 50549. EN50549 is much more specific in its treatment of unbalanced injection and the use of positive and negative components. These issues start to become complex very quickly and whilst two versions of the legal text were drawn up (ie one drawn up based on the discussion held in September and one drawn up based on EN 50549) the general view was that the initial approach suggested in September should be the one taken forward as the EN50549 is complex with the conclusion that any form of individual phase behaviour would be outside the scope of the workgroup.

However some very useful findings came out of these discussions in which it was agreed that in adopting the September option, the deadband should be changed to insensitivity and a number of detailed examples should also be prepared outlining how a plant would be expected to respond when operating in full lead or full lag and then subsequently exposed to range of voltage dips of various degrees ranging from 85% retained voltage to 10% retained voltage.

In addition, to reflect the difference between different technologies (ie full converter or DFIG etc), a relaxation was introduced into the drafting which effectively permitted a temporary drop below the shaded area provided this was agreed with National Grid. There is some concern how this could be interpreted as such solution would be to ensure the volume of reactive current supplied exceeds the minimum requirement specified in Figures ECC.6.3.16(b) and ECC.6.3.16(c).

In light of these discussions, a further presentation (with examples) and revised legal text was presented to the workgroup in December 2018. A copy of this presentation is shown in Annex 2D which includes the examples.

The revised voltage / reactive current characteristic is shown in Figure 6.0 below.

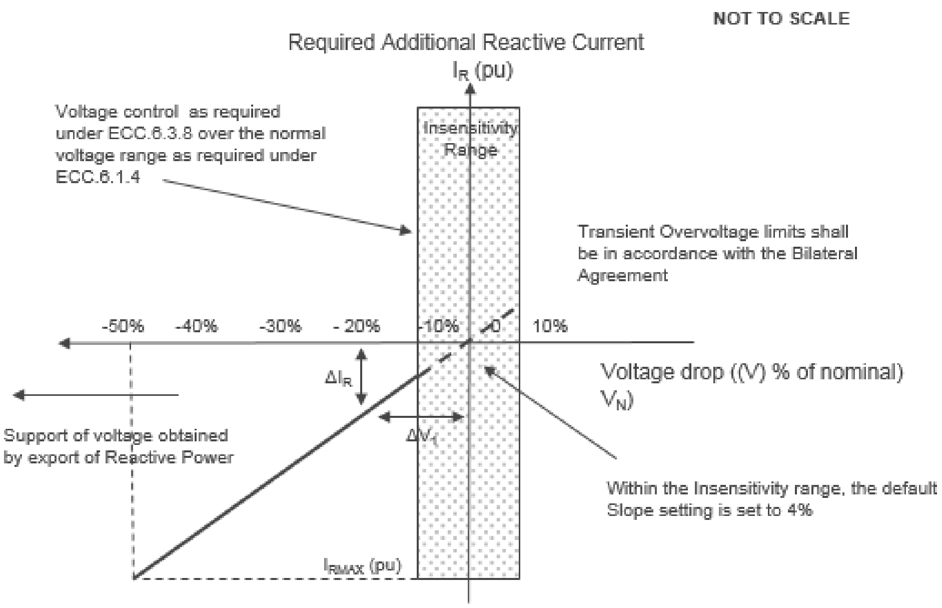

Figure 6.0

Where the corresponding formulae are:-

Where:-

V_N - Rated Voltage

V - Actual voltage at the Grid Entry Point or User System Entry Point during the fault

I_R - Additional reactive current where:_

$I_R = \Delta V_1.k + I_{Prefault}$ - (when V is between 50% and less than 90%)

$I_R = I_{RMAX}$ - (when V is less than 50% as defined by Figure ECC.16.3.16(b) or Figure ECC.16.3.16(c))

(I_R - Is the additional Reactive Current injected during the fault in per unit. This cannot exceed 1.0pu on the MVA Rating of the Power Park Module or HVDC Equipment as detailed in ECC.6.3.16.1.5)

In this approach where the voltage exceeds 50% the formula $I_R = \Delta V_1.k + I_{Prefault}$ and below 50% retained voltage, full reactive current would be required to be supplied.

At this point a number of stakeholders expressed concern over the mode change at retained voltages of 50% and at this meeting it was suggested that a formula based approach should be used over the entire voltage operating range. As a result, the following approach formula was proposed which would apply over the full voltage range.

V - Actual voltage at the Grid Entry Point or User System Entry Point during the fault

I_R - The reactive current supplied under fault conditions where:-

$I_R = \Delta V_1.k + I_{Prefault}$ (1)

I_R The Reactive Current supplied under fault conditions shall be above the shape shown in Figure ECC.16.3.16(b) and Figure ECC.16.3.16(c) with the peak steady state reactive current defined by Equation (1) above. This value is capped at a maximum of 1.0pu.

There is no requirement for I_R to exceed 1.0pu (I_{RMAX}) but this would not preclude a Power Park Module (or any constituent Power Park Unit) or HVDC Equipment from supplying more should it wish to do so.

ΔV_1 $= V_{prefault} - V_{insensitivity} - V_{retained}$

$V_{prefault}$ Is the Prefault Positive Phase Sequence RMS voltage in per unit

$V_{insensitivity}$ Is the voltage either side of nominal voltage and set at any value between 0 and 0.1 as agreed between The Company and the Generator - Default setting 0.1 unless otherwise agreed.

$V_{retained}$ Is the retained positive sequence voltage at the Grid Entry Point or User System Entry Point (under fault conditions)

k Is the gain factor (range proposed 2 – 7) – Default setting 2.5

$I_{prefault}$ is the prefault reactive current in per unit

The prefault reactive current ($I_{prefault}$) for a future fault ride through event, shall be determined when the voltage has returned above the minimum levels specified in ECC.6.1.4,

I_{RMAX} The maximum current which shall, as a minimum, be above the shaded areas defined by Figures ECC.16.3.16(b) or ECC.16.3.16(c). There is no requirement for the maximum supplied current to exceed 1.0pu.

Numerous examples of this approach at the extreme operating range (ie low and high pre-fault voltages) were prepared and these are shown in Appendix 2E [of the GC0111 Grid Code Code Administrator Consultation] and forwarded to the workgroup in January 2019.

For completeness two examples are shown below. In both cases the retained voltage is set at 50% with one case operating at a low pre-fault voltage and in another a high pre-fault voltage.

First Example –

Power Park Module operating at full MW output and full MVAr output – volt drop to 50% and $V_{insensitivity}$ set to 0.1 and K = 2.5

- Wind farm is operating at 100MW output and 0.95 PF lagging (ie 32.8MVAr or export to the System)
- $I_R = \Delta V_1.k + I_{Prefault}$
- And $\Delta V_1 = V_{prefault} - V_{insensitivity} - V_{retained}$
- If V Prefault = 0.96p.u and Q max = 0.95 PF lag on a 4% droop
- $V_{insensitivity} = 0.1$ p.u
- In this case the retained voltage ($V_{retained}$) is 0.5 pu
- $\Delta V_1 = V_{prefault} - V_{insensitivity} - V_{retained} = 0.96 - 0.1 - 0.5 = 0.36$
- $I_{prefault} = \sin(\arccos 0.95) = 0.312$pu
- $I_R = \Delta V_1.k + I_{Prefault} = 0.36 \times 2.5 + 0.312 = 1.212$ pu – *capped at 1.0pu reactive current*
- *IR at 60ms = (0.65 x* ΔV_1*.k)* + $I_{prefault} = 0.65 \times 2.5 \times 0.36 + 0.312 =$ 0.897 pu

Which when superimposed on Figure ECC.6.3.16(b) and ECC.6.3.16(c) results in Figure 7.0 and Figure 8.0

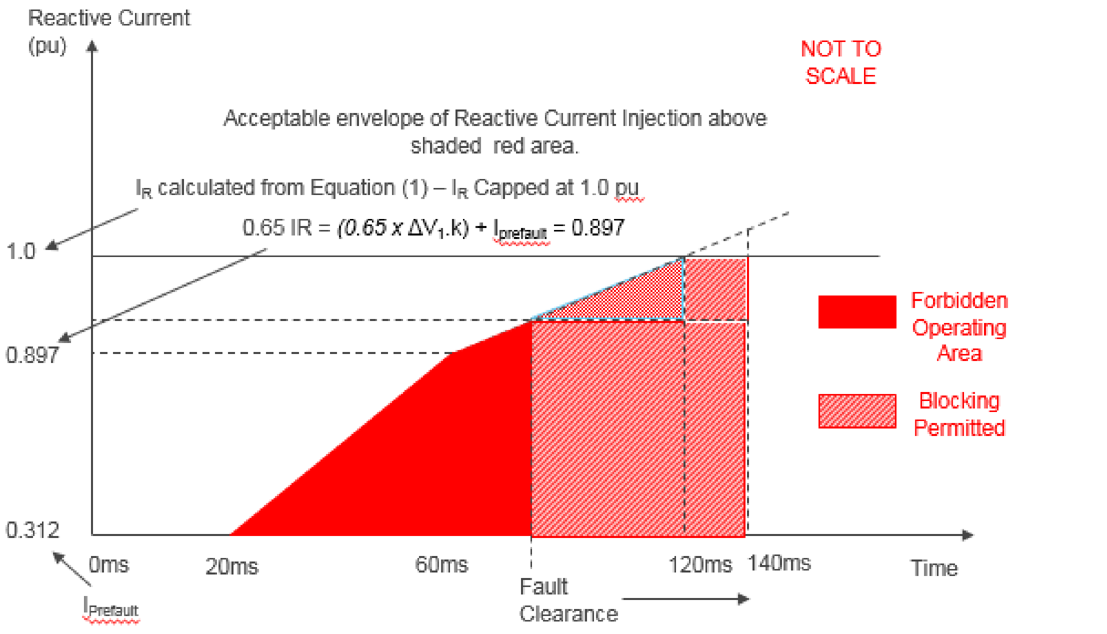

Figure 7.0

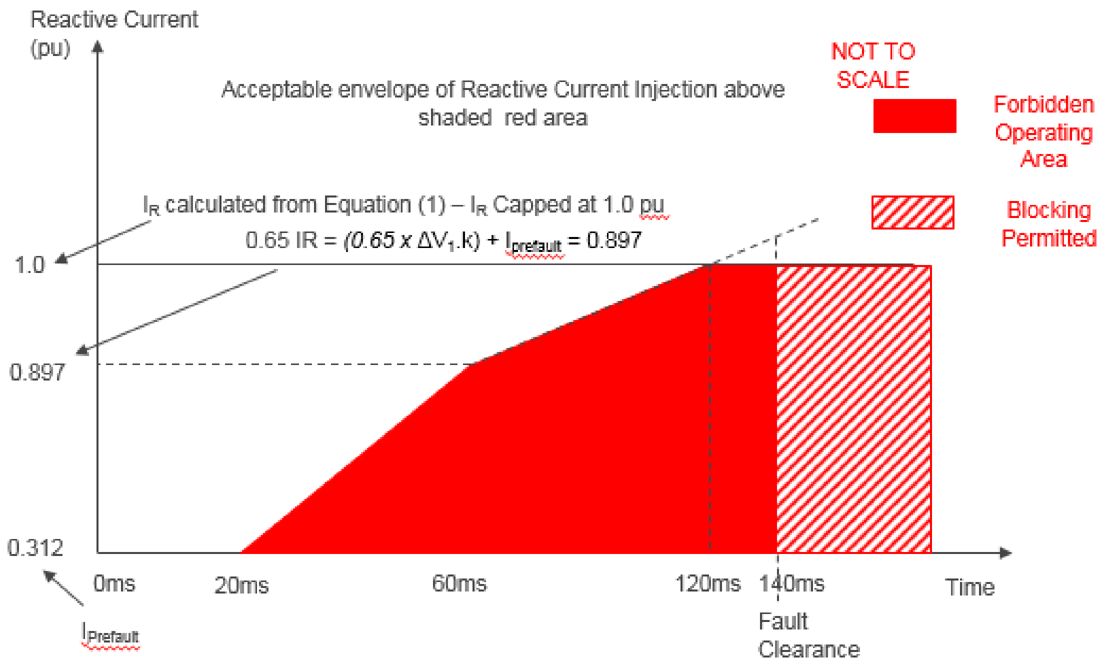

Figure 8.0

Second Example

Power Park Module operating at full MW output and full MVAr output – volt drop to 50% and $V_{insensitivity}$ set to 0.1 and K = 2.5

- Wind farm is operating at 100MW output and 0.95 PF leading (ie 32.8MVAr or import to the System)
- $I_R = \Delta V_1.k + I_{Prefault}$
- And $\Delta V_1 = V_{prefault} - V_{insensitivity} - V_{retained}$
- If V Prefault = 1.04p.u and Q max = 0.95 PF lead on a 4% droop
- $V_{insensitivity} = 0.1$ p.u
- In this case the retained voltage ($V_{retained}$) is 0.5 pu
- $\Delta V_1 = V_{prefault} - V_{insensitivity} - V_{retained} = 1.04 - 0.1 - 0.5 = 0.44$
- $I_{prefault} = \sin(\arccos 0.95) = -0.312$pu
- $I_R = \Delta V_1.k + I_{Prefault} = 0.44 \times 2.5 - 0.312 = 0.788$pu
- *IR at 60ms* = *(0.65 x* ΔV_1.k) + $I_{prefault}$ = (0.65 x 2.5 x 0.44) - 0.312 = 0.403 pu

Which when superimposed on Figure ECC.6.3.16(b) and ECC.6.3.16(c) results in Figure 9.0 and Figure 10.0

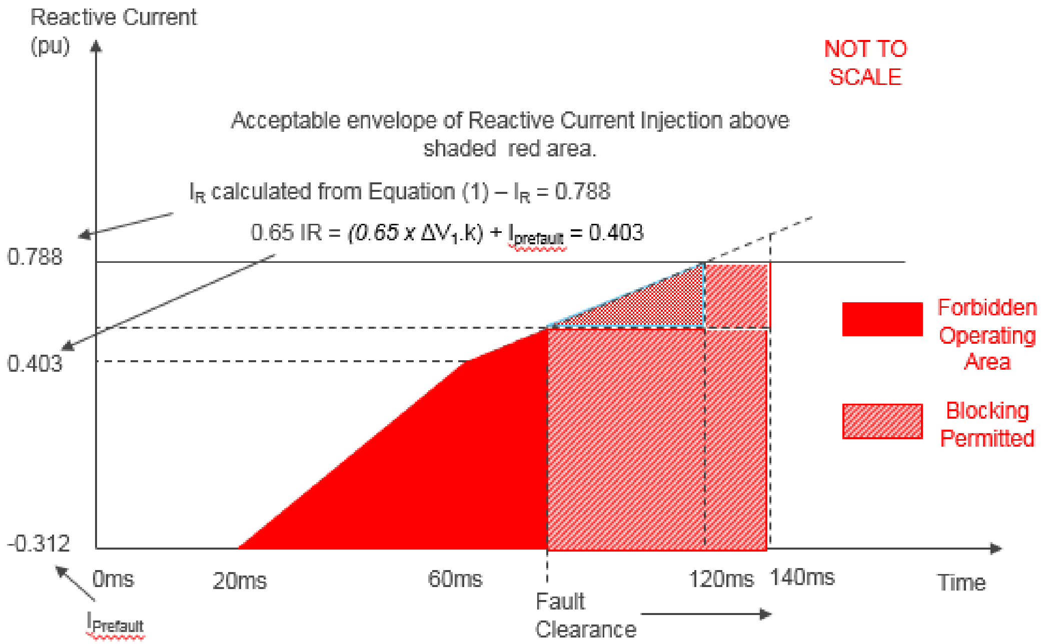

Figure 9.0

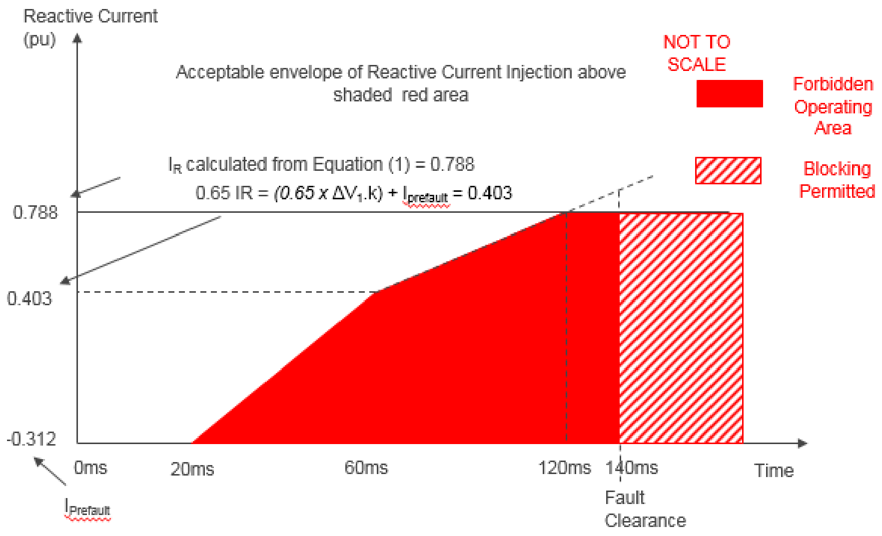

Figure 10.0

As can be seen in the leading example the injection of reactive current is lower than that in the lagging case which means that the gain factor (k) would need to be increased if full reactive current was to be achieved for a voltage drop of 50%. Whilst it is accepted that the delta (ie the reactive current swing) between the two is broadly similar, full reactive injection would be required under a faulted condition.

To address this concern, the effect can be limited by changing the formula so that the additional reactive current becomes $I_R = \Delta V_1.k + |I_{Prefault}|$ where $I_{prefault}$ becomes the modulus of $I_{prefault}$ and ΔV_1 simply becomes $V_{prefault} - V_{retained}$. Whilst there will be a slight difference between the reactive current injected between unity power factor and full lead or full lag, full reactive current would be obtained for a retained voltage of 0.5pu. This also means the k factor can be retained at 2.5 although in simplifying the formula this would require the need to make sure developers and manufacturers are comfortable with the transition from the steady state mode between the normal operational voltage of 0.9pu to 1.05pu and a faulted condition. The revised voltage drop / reactive current characteristic is shown in Figure 11.0.

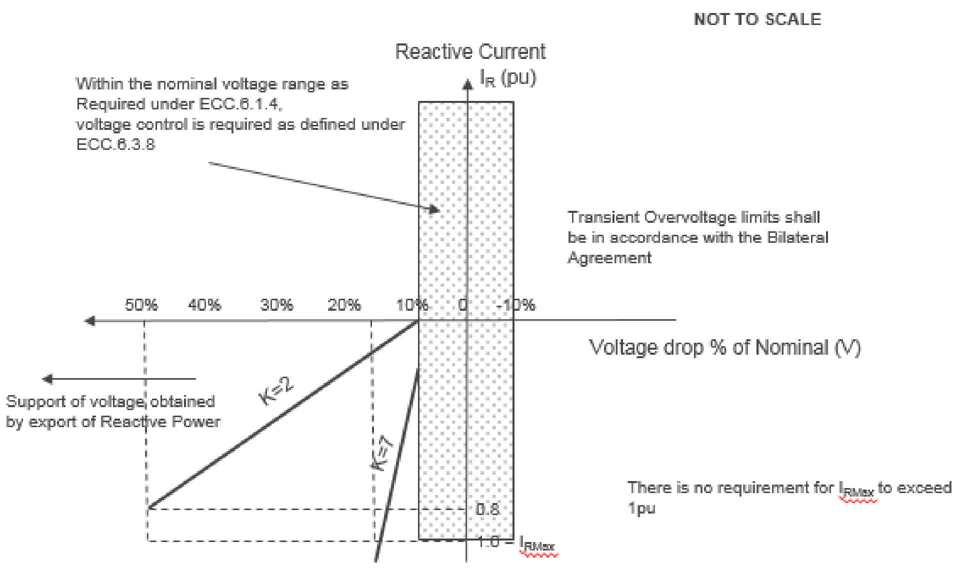

Figure 11.0

Where:-

V - Actual voltage at the Grid Entry Point or User System Entry Point during the fault

I_R - The reactive current supplied under fault conditions where:-

$I_R = \Delta V_1.k + |I_{Prefault}|$ Equation (1)

I_R - The Reactive Current supplied under fault conditions shall be above the shape shown in Figure ECC.16.3.16(b) and FigureECC.16.3.16(c) with the peak steady state reactive current defined by Equation (1) above. This value is capped at a maximum of 1.0pu.

There is no requirement for I_R to exceed 1.0pu (I_{RMAX}) but this would not preclude a Power Park Module (or any constituent Power Park Unit) or HVDC Equipment from supplying more should it wish to do so.

$|I_{prefault}|$ - is the modulus of the prefault reactive current in per unit the prefault reactive current ($I_{prefault}$) for a future fault ride through event, shall be determined when the voltage has returned above the minimum levels specified in ECC.6.1.4,

$\Delta V_1 = 0.9 - V_{retained}$

$V_{prefault}$ Is the Prefault Positive Phase Sequence RMS voltage in per unit

$V_{retained}$ Is the retained positive sequence voltage at the Grid Entry Point or User System Entry Point (under fault conditions)

k Is the gain factor (range proposed 2 – 7) – Default setting 2.5

I_{RMAX} There is no requirement for the maximum supplied reactive current to exceed 1.0pu.

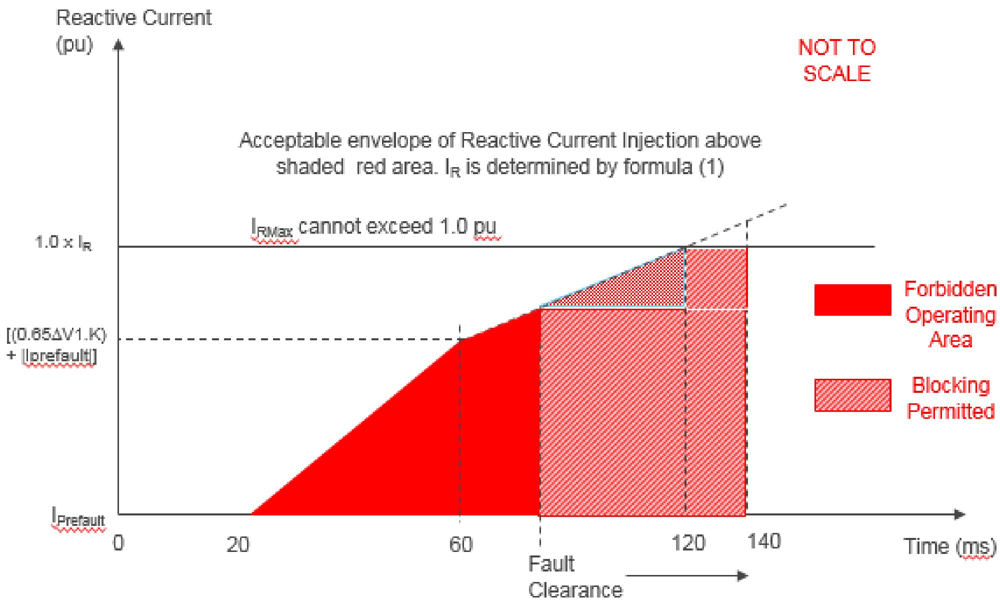

Figure 12.0

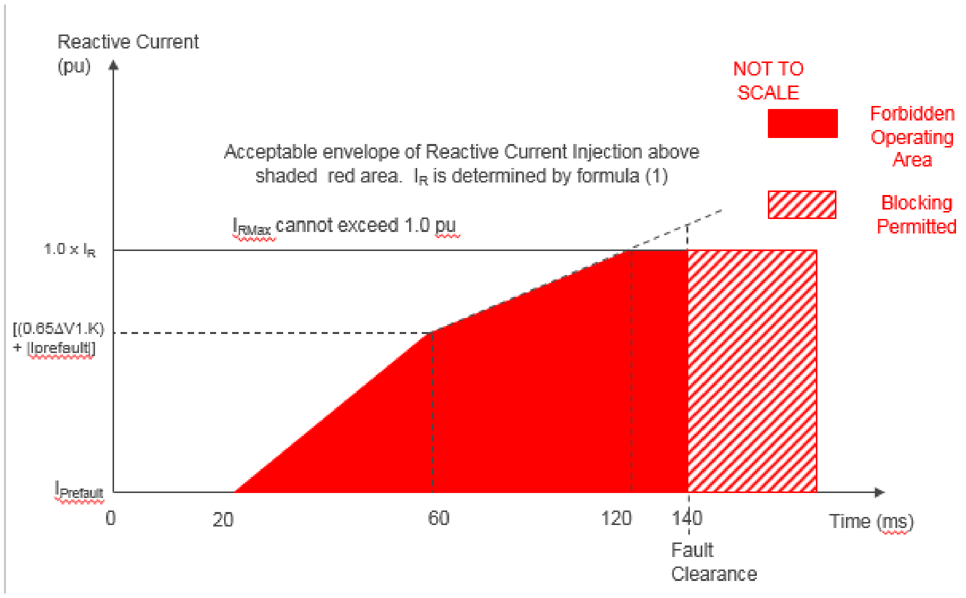

Figure 13.0

The problem with the above approach however is that there is still a difference between the reactive current injected and the pre-fault operating condition. There is also the risk of hunting between the normal voltage operating range and a fault ride through condition.

Final Proposed Reactive Current Injection Requirements

To investigate potential hunting issues figure 14.0 below shows a more detailed representation of the requirement between steady state operation and a fault ride through condition.

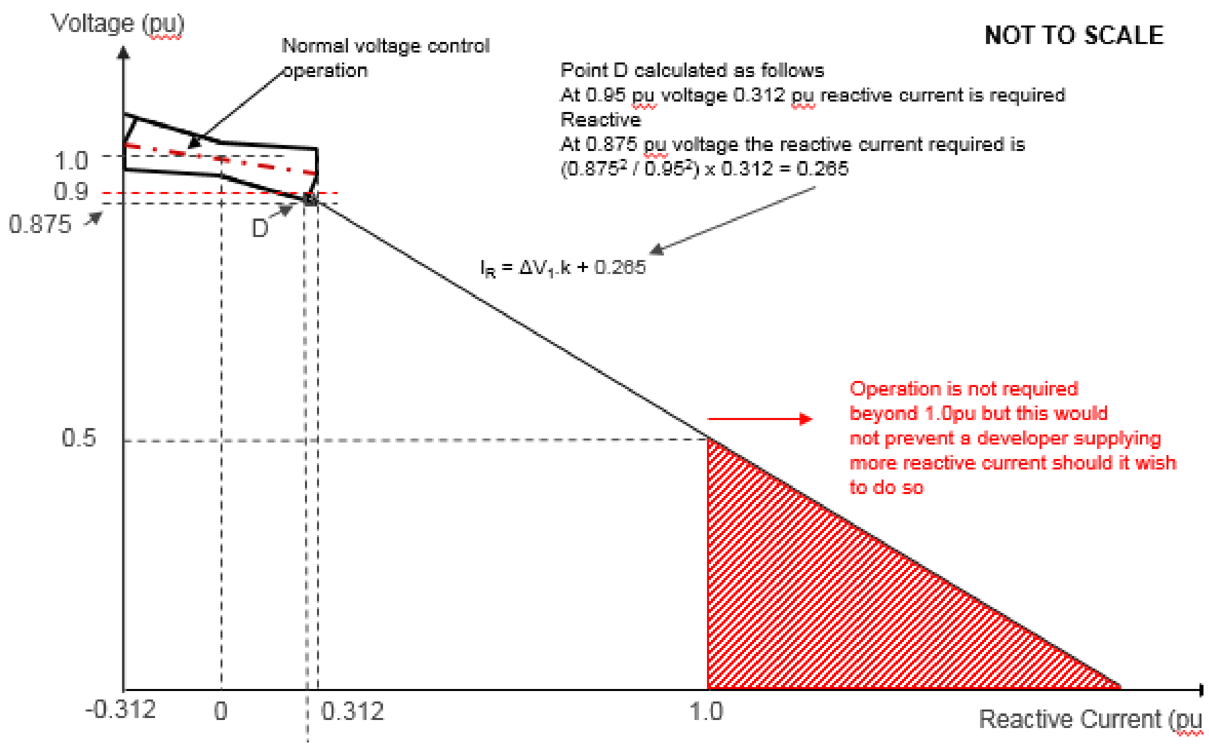

Figure 14.0

As part of this approach the proposal was for the reactive current injection to be defined by the following formula.

$$I_R = \Delta V_1.k + 0.265$$

and

$$\Delta V_1 = 0.9 - V_{retained}$$

In this case the gain factor K was set at 2.5 but can be varied between 2 and 7.

The advantage of this approach is that the reactive current injection will be the same irrespective of the pre fault operating point. In addition, as soon as the voltage drops to 0.5pu with a gain factor of 2.5, a reactive current injection of 1.0pu will be delivered.

The problem with this approach is that some developers and manufacturers could struggle with the requirement especially in the common case for distribution connected modules if the plant was operating in power factor control mode or reactive power control mode and the Connection Point Voltage remained at 0.9pu and the generator was operating under full import – although such an operating point itself is not likely. To address this issue, it was suggested at the February 2019 Workgroup meeting that the normal voltage operating envelope should be retained and an envelope of operation defined between the two black lines (ie starting at the extreme ends of the voltage operating range at 0.9pu and 1.1pu voltage and ending at the intersection of the 0.5 pu voltage and 1pu reactive current point). This characteristic is shown in Figure 15.0 below but would at least ensure a progressive injection of reactive current between 0.9pu and 0.5 pu voltage whilst ensuring below 0.5pu voltage the full 1.0pu reactive current would be delivered.

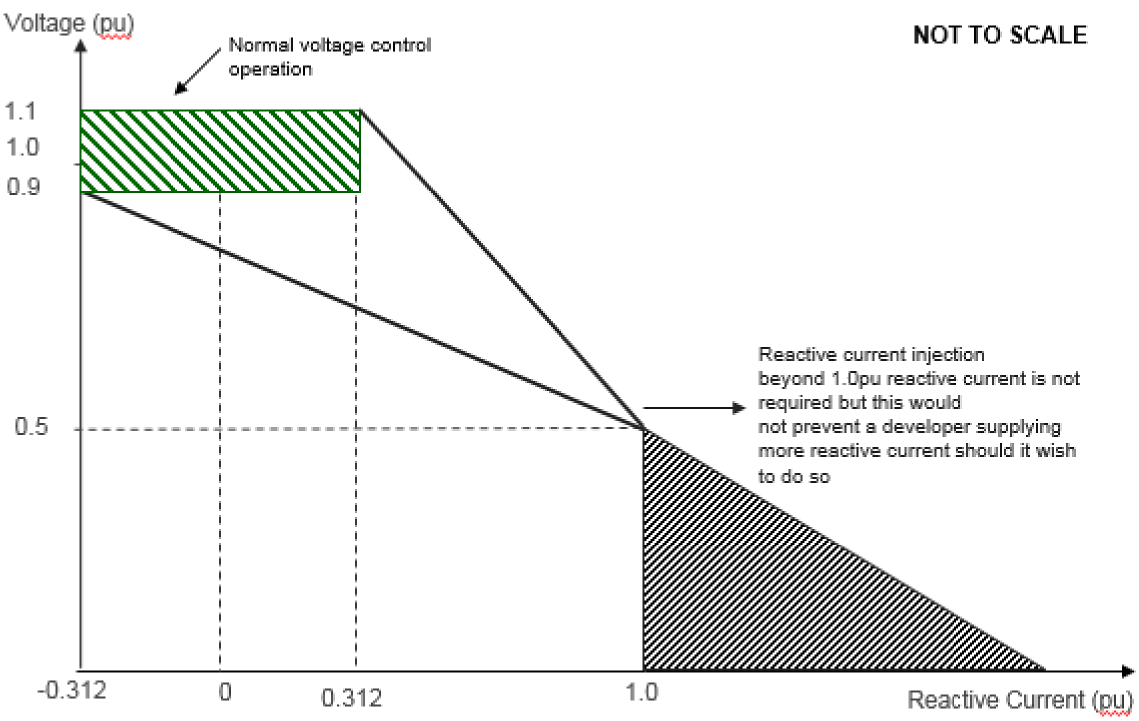

Figure 15.0

In this case, the point was raised that a plant could be operating at 0.9 power factor in a leading mode of operation at 0.9 pu voltage which could only apply in a power factor or reactive power mode of operation and even then in the unlikely event this were to occur, the voltage would have to drop for a small amount even to get zero injection of reactive current although there would be a delta change (i.e. the difference between the final reactive current injection and the pre-fault reactive current injection) in transiting from a fully leading power factor to unity.

To address this concern, two points were raised. The first, that irrespective of the operating point within the normal voltage operating range, the locus of I_R should converge to the 0.5pu voltage / 1.0pu reactive current coordinate so as not solely to give a minimum performance requirement. Secondly, some concern was expressed as to how this requirement would interface with Figures ECC.6.3.16(b) and ECC.6.3.16(c). A comment was also noted that the upper boundary would not be required.

To illustrate the concept of this approach, two examples are shown below. It should be noted that the diagrams associated with these examples are for illustration purposes only and not to scale.

Figure 16 shows an illustrative requirement of the behaviour expected from a plant operating in the leading mode of operation and the I_R value required when subject to a voltage dip of 0.7pu at the connection point.

In this case, the pre-fault operating condition is assumed to be arbitrarily operating at 1.07pu voltage and the reactive current is -0.3pu. This is shown by the blue circle in the green shaded area. The reactive current injection can take any shape being linear or non-linear but would need to be on or above the blue dashed line shown in Figure 16 constructed between points A and B.

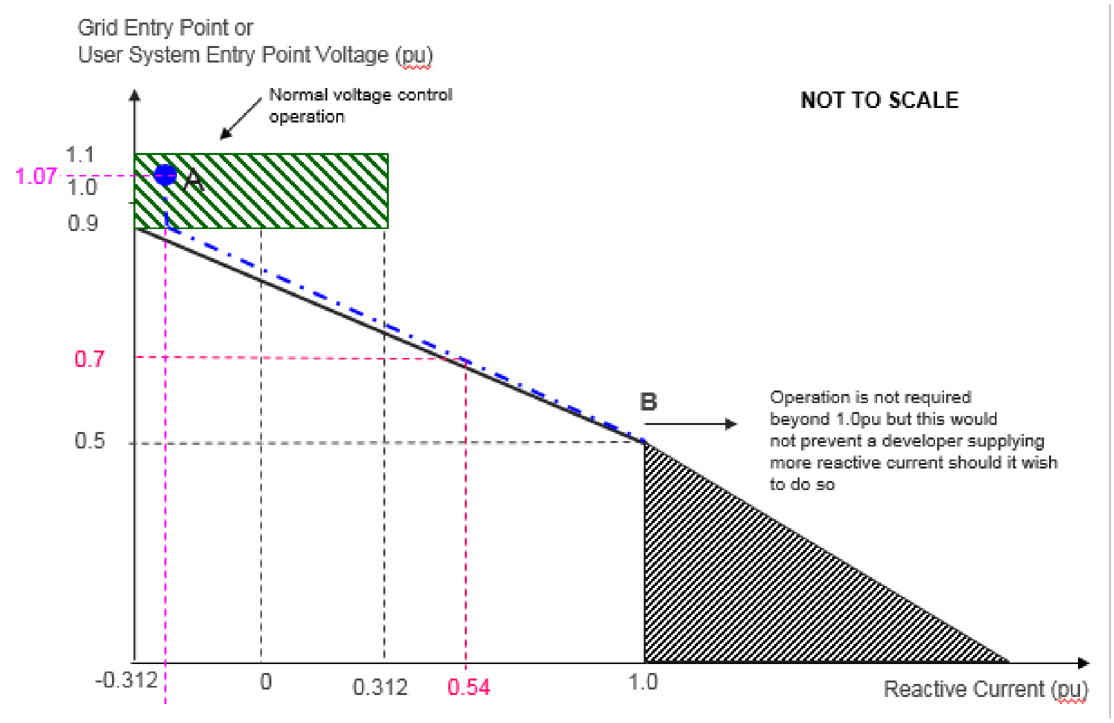

Figure 16.0

For the purposes of this example we are assuming the Power Park Module is exposed to a voltage dip of 0.7 pu. At 0.7pu voltage this corresponds to I_R of 0.54 pu reactive current as shown by the purple dashed line and where it intersects with the blue dashed line. I_R would need to be greater than or equal to 0.54.

In terms of time frames and reactive current injection and the minimum performance requirement that would be expected is shown in Figures 17 and 18. In summary the reactive current injection would need to be 0.54pu or above by 120ms after fault inception, with any residual current (ie taking into account the converter rating) being supplied as active current. There is no real difference between these two figures other than in respect of the fault clearance time.

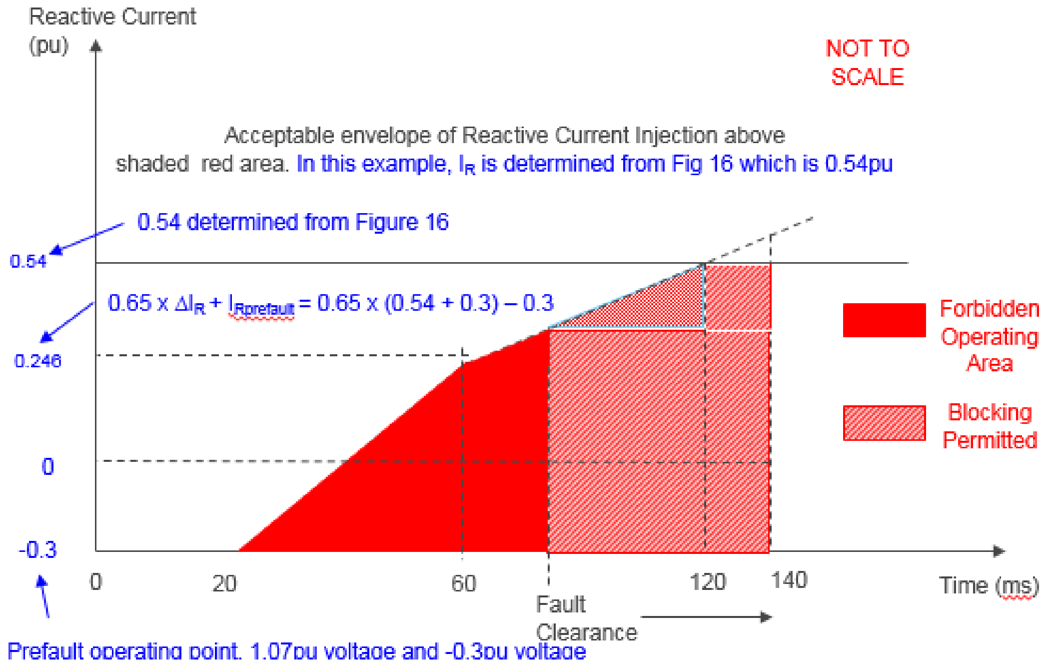

Figure 17

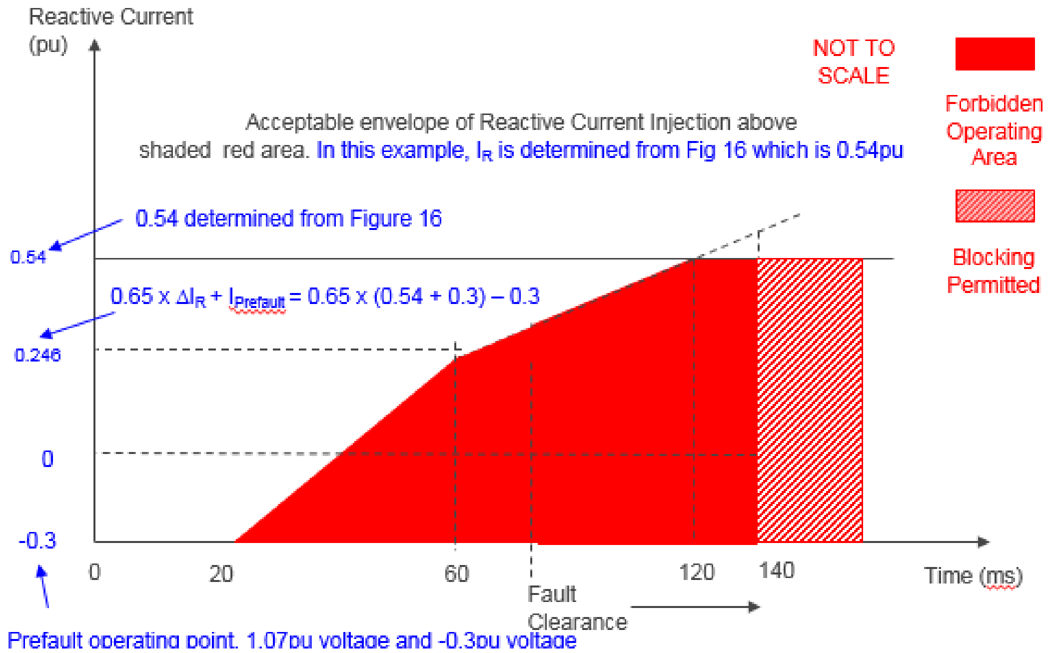

Figure 18

Example 2 is shown in Figure 19 which shows an illustrative requirement of the behaviour expected from a plant operating in the lagging mode of operation and the resultant I_R required when subject to a voltage dip of 0.7pu at the connection point.

In this case, the pre-fault operating condition is assumed to be arbitrarily operating at 0.96pu voltage and the reactive current is 0.312pu. This is shown by the brown circle in the green shaded area. Applying the same approach as in example 1, the brown dotted line constructed between points A and B of Figure 19 indicates the I_R required as a function of the retained voltage. However we need to ensure that the rating of the plant is not exceeded and therefore an additional pink line at point C is drawn. This reduction is permitted as the Grid Code requires full reactive capability to be provided over a voltage range of 1.05pu to 0.95pu. Below 0.95pu voltage, a drop in the reactive power export is permitted as it is possible a number of developers may choose to use fixed capacitors to contribute to voltage control in which case the reactive power falls off with the square of the voltage. This characteristic showing the allowed fall in reactive power is shown in Figures ECC.A.7.2.2b and ECC.A.7.2.2c of Appendix 7 of the Grid Code European Connection Conditions.

For the purposes of this example, we are assuming the Power Park Module is exposed to a voltage dip of 0.7 pu. At 0.7 pu voltage this corresponds to a I_R of 0.64 pu reactive current as shown by the purple dashed line and where it intersects with the pink dashed line at 0.7pu voltage.

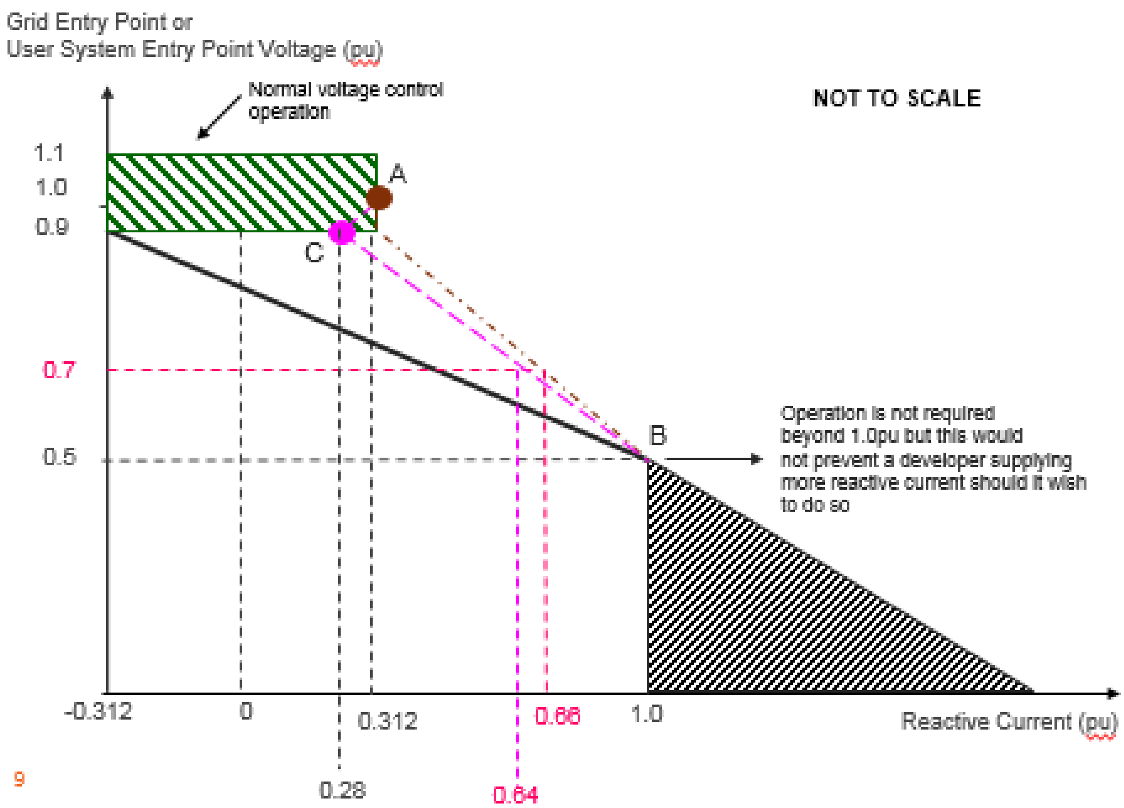

Figure 19.0

In terms of time frames and reactive current injection the minimum performance requirement that would be expected is shown in Figures 20 and 21. There is no real difference between these two figures other than in respect of the fault clearance time. In this example the green hashed area is showing the effect of the pre-fault operating condition of the Power Park Module.

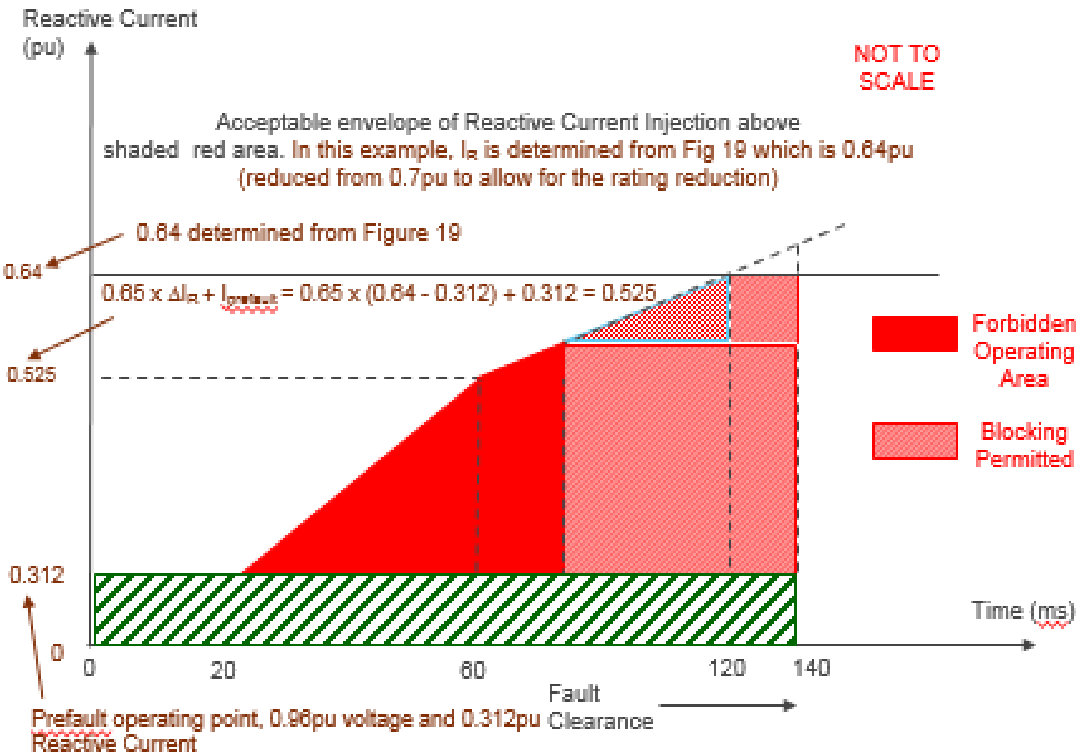

Figure 20.0

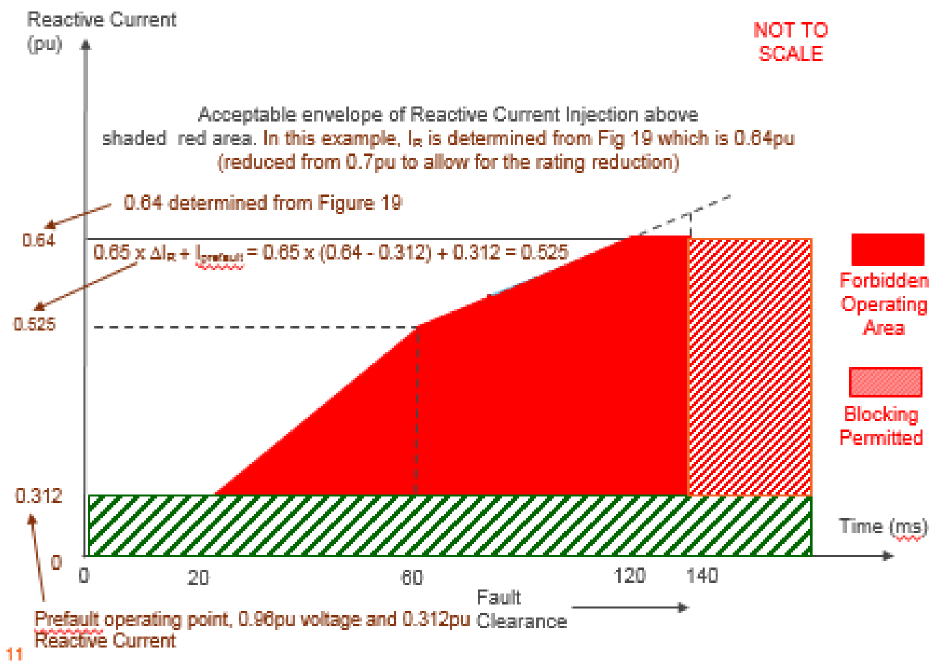

Figure 21

The above approach was discussed amongst the workgroup at the meeting on 7 February 2019 and re-discussed at a later meeting on 13 February 2019. To fix the second deficiency that the current Grid Code text is not clear how the reactive current should vary with depressed voltage, changes to Grid Code sections ECC.6.3.16.1.1 to ECC.6.3.16.1.5 has been modified based on the above discussion text.

Also as part of the proposal following workgroup discussion it was agreed to separate out the requirements for balanced and unbalanced faults, as RfG leaves the behaviour of unbalanced faults and fast fault current injection performance to the TSO, by removing the word “unbalanced” from ECC.6.3.16.1.2.

Workgroup Discussions

The Workgroup convened four times between July 2018 and February 2019 to discuss the perceived issue, detail the scope of the proposed defect, devise potential solutions and assess the proposal in terms of the Applicable Grid Code Objectives.

The Workgroup discussed a number of the key attributes under GC0111 and these discussions are described below.

Workgroup 1 – 4 July 2018

The slides presented by National Grid as Electricity System Operator are attached in Annex 2A [in the Grid Code Code Administrator’s Consultation]. In summary, this concentrated on the background to the issue, the defect and the key clarification that during a fault there is no requirement for the Power Park Module to exceed its rating. In addition, the point was also raised with regard to the defect in ECC.6.3.16.1.4 which states “the reactive current injected from each Power Park Module or HVDC Equipment shall be injected in proportion and remain in phase to the change in System voltage at the Connection Point or User System Entry Point during the period of the fault.

At the workgroup meeting it was advised that some form of specification would be required to detail how the reactive current should vary with depressed voltage and address the linkage between the fault ride through requirements in ECC.6.3.15 and the fast fault current requirements in ECC.6.3.16.

Workgroup 2 – 10 September 2018

A presentation was provided by the National Grid Electricity System Operator (NGESO) representative to the Workgroup which is attached in Annex 2B [in the Grid Code Code Administrator’s Consultation]. The NGESO representative advised that the aim of the legal text would be to keep the requirements as generic but robust as possible. The following is the discussion on the proposed draft legal text as of 10 September 2018.

A Workgroup member stated that he found it difficult to follow all of the proposed graphs and therefore suggesting to only keep the graphs for Transmission connections but it may be useful to specify a description which would be equally effective.

A Workgroup member stated that in Figure ECC.16.3.16(a), a statement on what the maximum voltage and proportionality criteria needed to be clarified. It was agreed that this is what the graph was trying to achieve.

A Workgroup member queried whether the figures in ECC.16.3.16(a) are absolute figures. The NGESO representative tried to address this issue but further thought and clarity was needed for the legal text.

The NGESO representative referred to Figure ECC.3.16(b) and stated that the Workgroup needs to consider whether this would be a rise time or a settlement time. He explained that the reactive current has to be above the red section on the figure. The control performance should be adequately damped.

Another Workgroup member stated that their comments had already been addressed and they will forward some comments by E Mail to aid the drafting of the legal text.

A Workgroup member queried how the changes on RfG were going to be taken forward. The NGESO representative confirmed that the RfG requirements were captured in GC0100 EU Connection Codes GB Implementation Mod 1 and these have now been implemented into the Grid Code. However, it did not capture faults greater than 140 ms which have been retained as part of the existing GB Code drafting.

A Workgroup member stated that it is common for type tests to be completed for fault ride through. There may not be clear testing requirements, so this will need some clarity.

The NGESO representative informed the Workgroup that it was discussed that it is not possible to demonstrate on a module basis but you can do so on individual turbines basis. There is a challenge in articulating this in the Grid Code legal text as the Grid Code is based around a performance requirement for the module rather than the turbine. Although the text is written with respect to Power Park Module performance, the proposed text does provide a clause for assessment at a unit level.

A Workgroup member queried what would happen if the voltage drops below 1 per unit ie what would be the consequences as the Power Park Module could include various combinations as there is a phase between operation within the normal voltage operating range (ie ±10%) and under fault ride through conditions. The NGESO representative stated that they would review this when looking at the legal text.

The NGESO representative clarified that in relation to slide 11 that below 50% is a priority for reactive current injection and above 50% there should be a minimum requirement to supply reactive current with any residual being supplied as active current. It was agreed that it needs to clarified which of these are the priority and this needs to be clearly articulated. A Workgroup member queried whether there needed to be an example around where the voltage drops below 50%. The NGESO representative stated that where the voltage drops below 50% the reactive current should be prioritised.

A Workgroup member queried whether the proposal was asking for absolute levels of current. The NGESO representative stated that he would review whether these are absolute values or delta values.

A Workgroup member raised in relation to ECC.6.3.16.1.4 that if this is a requirement, then this should be in the compliance section of the Grid Code as opposed to the European Connection Code. The NGESO representative agreed to discuss this with the National Grid Compliance Team before updating the legal text.

A Workgroup member queried where the items specified in Article 20 are reflected in the draft legal text? The NGESO representative stated that as part of the mapping exercise that was completed as part of the GC0100 consultation.

The NGESO representative confirmed that he would take the Workgroup feedback on board, amend the legal text and recirculate it around the Workgroup for comment. Part of this analysis would be to ensure there is consistency between the proposed legal text and the European Connection Codes.

Workgroup 3 – 7 November 2018

A presentation was presented by the National Grid Electricity System Operator (NGESO) representative to the Workgroup which is attached in Annex 2C [in the Grid Code Code Administrator's Consultation].

Following discussions and emails in between the Workgroups, the NGESO representative drafted and presented to the Workgroup two draft versions of legal text – 1A and 1B. As noted above version 1A was based on the draft text discussed at the September meeting and version 1B incorporates elements from the fast fault current injection requirements of EN50549.

A Workgroup member stated that they would suggest not using pre-fault in the formula on slide 7 of the slide pack. In addition, some practical examples would be helpful to understand the requirements better.

A Workgroup member observed that the changes to voltage would have a minimal impact on Distribution Network Operators.

In relation to the legal text – version 1A, the NGESO representative stated that the diagram on slide 10 is in relation to the sum of all the turbines.

In relation to legal text – version 1B, the NGESO representative stated that incorporating EN50549 means that it becomes very complex very quickly but does more easily address the issue of unbalanced faults. Based on discussions prior to the Workgroup, the NGESO representative stated that it seemed that the majority of the Workgroup were in favour of legal text -version 1A although it was recognised that it needed further work including agreeing a recommendation for implementation. Legal text 1A will result in minimal impact on the industry when devising the solution.

A Workgroup member queried whether the EN50549 requirements link to HVDC equipment and queried whether any Workgroup members manufacture that kind of equipment to ensure their view is reflected. The NGESO representative confirmed that this did relate to HDVC Equipment and that there are Workgroup members from Siemens who manufacture HVDC equipment.

The Workgroup unanimously agreed that the Workgroup should proceed with version 1A of the legal text for the solution.

The Workgroup reviewed the legal text by exception to allow the legal text to be further developed.

A Workgroup discussed the timeline, and agreed that they wanted to talk through some worked examples before deciding whether to proceed to a Workgroup consultation.

The Workgroup discussed the terms of reference set by the Grid Code Review Panel:

a. Implementation and costs

   In terms of costs, the NGESO representative stated that the implementation will be linked to contracts and that the aim is to minimise any costs as the changes to the legal text are for clarification purposes only and should not result in additional cost.

b. Develop draft the legal text

   This is currently in progress and will be completed to be submitted with the Workgroup Report to the Grid Code Review Panel.

c. Consider whether any further industry experts or stakeholders should be invited to participate in the Workgroup

   This has been done on an ongoing basis. The Workgroup is comprised of industry experts. The NGESO representative expressed his gratitude for the participation and help given so far in developing the solution.

d. Consider the materiality of the change

   The materiality of the change is low as the purpose of the modification is to provide clarity to industry.

e. Requirement for a Workgroup Consultation

   This is unknown until the Workgroup has seen some worked examples. At that point the Workgroup can decide whether to proceed to a Workgroup consultation.

f. Review the trigger voltage and Fault Ride Through requirements and whether the changes are compatible

   The NGESO representative stated that this is a National Grid issue and he believes this is minimal. He will continue to consider this as the solution is developed.

One Workgroup member provided a spreadsheet showing plant performance, which was circulated to the Workgroup.

Workgroup 4 – 6 December 2018

A presentation was presented by the National Grid Electricity System Operator (NGESO) representative to the Workgroup which is attached in Annex 2D [in the Grid Code Code Administrator's Consultation].

The NGESO representative presented to the Workgroup a presentation which included a number of worked examples to demonstrate how the proposed solution would work in practice.

The Workgroup discussed compliance and agreed there needed to be section on compliance legal text included in the solution to complete the modification.

A Workgroup member queried whether there was a need for a further compliance modification as there are a number of issues that needed to be addressed.

The Workgroup agreed to continue to use the term "insensitivity" as opposed to dead band to provide greater clarity to Grid Code users.

A Workgroup member queried when the 20 milliseconds in example 5 starts. It was agreed that NGESO would look at this.

The Workgroup discussed the formula in example 2 of the slide pack (see Appendix 1D) and it was agreed that the NGESO representative would review the formula and re-circulate this around the Workgroup.

On slide 36, The NGESO representative stated that based on the approach set out in slide 36, it is possible to calculate the FFCI Power Park Module performance requirement at the connection point and work back to each turbine.

In terms of the implementation, it was agreed by the Workgroup that the approach should be that it runs from the signing of the contract rather than the completion date of plant installation though care needed to be exercised as the current Grid Code drafting is not that clear.

A Workgroup member asked for the implementation to be clearly set out including how long it will take manufacturers to implement this modification.

Based on the worked examples, the Workgroup agreed that a Workgroup consultation was not necessary or required to develop the solution.

<u>Workgroup 5 – 7 February 2019</u>

A presentation was presented by the National Grid Electricity System Operator (NGESO) representative to the Workgroup which is attached in Annex 2E.

At this meeting, the NGESO representative outlined the revised thinking based on the stakeholder comments received in January. At this meeting, the NGESO representative highlighted that the current drafting as prepared in December 2018 and circulated to the Workgroup in January 2019 still presented a few issues, but these mainly related to the variation in injected reactive current depending upon whether the plant was operating in a pre fault leading or lagging mode of operation. To this extent the NGESO representative suggested changing the formula as follows:-

$$I_R = \Delta V_1.k + 0.265$$

and

$$\Delta V_1 = 0.9 - V_{retained}$$

The details of this approach are summarised in section 3 [ie on page 17 of this current document] however a number of Workgroup members stated that this would cause a number of problems.

The Proposer did note at this stage that they were clear what was required which in principle required injection of reactive current in a progressive manner as the retained voltage starts to fall with the full reactive current injection of 1.0pu required at retained voltages of 0.5pu or less.

As a consequence of this, a number of options were discussed which revolved around a solution defining a criterion around a minimum requirement injection requirement between the normal steady state operating range and the need to inject 1.0pu reactive current at connection point voltages of 0.5pu or less.

A number of slides around this discussion were developed at the meeting and these are shown in Annex 2F. This approach and detailed examples are shown in Section 3 which the Proposer is comfortable with and which is believed to provide the best approach for this solution.

As part of the discussion the issue of compliance was also mentioned and it was advised that developers would be able to have the option of demonstrating compliance at the Generating Unit terminals should they so wish. This will be included in the revised legal drafting.

One Workgroup member expressed concern over the requirement for unbalanced faults. It was suggested that they may wish to raise a Workgroup Alternative to address this issue.

As a post meeting note, NGESO considers that a simple way in which this issue could be addressed is based on the fact that RfG for Fast Fault Current Injection does not apply to Unbalanced Faults and it down to the TSO to define this requirement. Put simply, and with this flexibility, it would enable the text to revert back to the GB Grid Code requirement pre RfG which simply states that in the case of unbalanced faults, the Power Park Module should inject maximum reactive current without exceeding the transient rating of the Power Park Module or HVDC Equipment whilst any such performance requirement would need to be agreed with NGESO against the control philosophy of the design. This issue was addressed and included in the updated legal text which was discussed with Stakeholders at the Webex held on 13 February. For distribution connected plant there is no pre-existing FFCI requirement and the same approach will be adopted for distribution connected Power Park Modules.

<u>Workgroup 6 Webex – 13 February 2019</u>

Following the meeting held on 7 February 2019, it was proposed to hold the workgroup vote based on an updated workgroup report and legal text which was circulated on 8 February and 11th February respectively. Following the re-issue of this text a number of comments were received and these issues were discussed at the meeting with the decision taken to delay the vote until Workgroup members had been given adequate time to re-assess the workgroup report and legal text.

The final proposal as drafted and the approach proposed is summarised in section 3 of this report. It was also agreed to treat unbalanced faults separately from balanced faults and the legal text has been updated to address this.

During the discussion, one workgroup member suggested ECC.6.3.15.9.2.1(b)(ii) be changed to refer to 0.9pu voltage rather than the minimum voltage levels specified in ECC.6.1.4. The Proposer considered this change but felt it would not be entirely correct as the voltage range varies depending on connection voltage. For example, at voltages of 275, 132 or 100kV the voltage range is ±10% whereas for connection voltages below 110kV the voltage range is ±6%. As such the proposer declined to make this change.