Stage 02: Industry Consultation

Grid Code + Distribution Code

# GC0048 Requirements for Generators EU Network Code implementation

## GB proposals for Voltage / Reactive Power Capability

What stage is this document at?

| | |
|---|---|
| 01 | Workgroup Recommendation |
| 02 | Industry Consultation |
| 03 | Report to the Authority |

This consultation sets out proposals formed by industry Workgroup GC0048 to modify the Grid Code and Distribution Code to set out the voltage / reactive power capability requirements as set out in the 'Requirements for Generators' EU Network Code. This is a requirement to ensure GB compliance with EU law

This document is open for Industry Consultation. Any interested party is able to make a response in line with the guidance set out in Section 5 of this document.

**Published on:**
**Length of Consultation:** **30 Working Days**
**Responses by:** **31st January 2017**

***GC0048 Workgroup recommends:***

***High Impact:***
Developers of Transmission or Distribution connected generation schemes of ≥1MW in capacity;

***Medium Impact:***
The GB Transmission System Operator; GB Distribution Network Operators;

***Low Impact:***

## Contents




**Any Questions?**

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## About this document

This document outlines the information required for interested parties to form an understanding of a defect within the Grid Code. It seeks the views of interested parties in relation to the proposed solution(s) for this defect and any associated Grid Code legal text changes.

## Document Control

| Version | Date | Author | Change Reference |
|---|---|---|---|
| 0.1 | December 2016 | National Grid; ENA | Draft Industry Consultation |

# 1 Executive Summary

1.1 The European Network Code 'Requirements for Generators' (RfG) applies technical requirements to new generators of 800 Watts (W) in capacity or greater, who procure their main plant items later than two years after the code 'Enters into Force'. In some cases existing power generating modules may be bound by RfG, for example, if they undertake significant modernisation which necessitates substantial revisions to their connection agreement.

1.2 The joint Distribution Code/Grid Code Workgroup GC0048 (T) has discussed the Reactive Power and Voltage control proposals at length with meetings held between May – November 2016. Stakeholders have had the opportunity to comment on the high level proposals which are being presented in this document for wider industry consultation.

1.3 This consultation is one element of the Connection Codes that are anticipated to be necessary to implement the RfG into the GB framework. It is expected that other RfG issues (e.g. Fault Ride Through, Fast Fault Current Injection, Compliance and System Management) will be consulted separately during 2017. Although legal text will be consulted, it is also expected that there will need to be a final implementation consultation in late 2017 that ties all the previous RfG consultations together in a single set of legal text for implementation in 2018.

1.4 The current GB Grid Code and Distribution Code encapsulate existing design and operational experience. As such, the approach adopted in this consultation is to apply the same GB requirements going forward with changes only necessary where there is either i) a conflict between the GB Codes and RfG (with RfG taking precedence) or ii) the effect of recent changes on the power system which may necessitate the need for alternative technical requirements, for example the significant growth of embedded generation which is starting to place a greater emphasis on the need for voltage control rather than power factor or reactive power control, whilst noting that voltage control may not be appropriate in all applications.

1.5 The Requirements for Generators (RfG) document places requirements on Generators according to four Bands (Type A, B C and D). The requirements are cumulative meaning that the requirements that apply to Type D plant also include the requirements that apply to Type A, B and C Power Generating Modules.

1.6 RfG does not specify any reactive power requirements on Type A Power Generating Modules. The reactive power capability and control performance requirements applicable to Type B to D Power Generating Modules are split between Synchronous Power generating modules and power park modules, which reflects the differences in technology.

1.7 For Type B power generating modules, the reactive power capability requirements are fairly rudimentary with the fundamental requirements being specified by the System Operator if required. In this context (as defined under RfG) the System Operator would effectively be considered to be NGET or the Relevant Distribution Network Operator.

1.8 In terms of control performance requirements, Type B Synchronous Power generating modules are required to be equipped with a permanent automatic excitation control system that can provide constant alternator terminal voltage at a selectable setpoint without instability over the entire operating range of the Synchronous Power generating module. The Workgroup acknowledged that the System Operator may require control performance requirements and a reactive power capability performance requirement at the connection point rather than at the alternator terminals. As such, the legal drafting has been prepared to provide maximum flexibility and permit Synchronous Generating Units which are installed within an industrial network or some other network to operate to a droop characteristic or otherwise as agreed with the System Operator.

1.9 In respect of Type B Power Park Modules, RfG does not mandate any form of control requirement (i.e. voltage control, reactive power control or power factor control). The Workgroup discussed this issue and proposed that the RfG requirements for Type B Power Park Modules (irrespective of being Transmission or Distribution connected) should be the same but allowing for the flexibility under RfG which permits the Relevant System Operator (i.e. the SO or DNO) to specify the control requirements in the site specific Connection Agreement.

1.10 For Type C and Type D Power Generating Modules, the requirements for reactive capability are specified in a very different way to that in the GB Grid Code. Again the requirements are split between Synchronous plant and Power Park Modules.

1.11 For Synchronous Generating Units in GB who are obligated by the Grid Code the reactive power capability range and voltage control performance requirements are specified at the terminals of the alternator. In the case of Power Park Modules, the Grid Code generally specifies the Reactive Power capability and voltage control performance requirements at the Connection Point; for Embedded Generators, caught solely by the requirements of the Distribution Code, the requirements of the Distribution Code and G59/G83 would apply.

1.12 Under RfG, the reactive power capability and voltage control performance requirements for both Synchronous Generators and Power Park Modules are defined at the Connection Point. Furthermore, these requirements are defined in terms of P/Qmax capability over a voltage operating range at the connection point; rather than a Power Factor requirement at rated MW output as per current GB practice. In general, the reactive power capability and voltage control performance requirements for Type C and D Power Generating Modules can be broadly mapped to those already in the GB Grid Code noting that for Synchronous Power Generating Modules the detailed excitation performance requirements are only covered for Type D. This issue was discussed amongst the Workgroup and it was noted that such requirements would be equally appropriate to Type C Synchronous Power Generating Modules. The only significant issue is that RfG mandates the requirement for Type D Synchronous Power Generating Modules to be fitted with a stator current limiter. This issue has been noted and included in the legal drafting but not believed to have significant implications. In terms of Power Park Modules, again the voltage control performance requirements broadly map to the existing GB requirements other than slight differences in the HV voltage operating range and response time $t_2$ (the time required to settle to a new steady state operating point following a step change in voltage). Again these changes are believed to be minor.

1.13 For Type C and D Power Generating Modules, voltage control is generally the required performance requirement. However the legal text has been drafted to permit flexibility in this area allowing System Operators to specify reactive power control or power factor control if required. Where such control capability is required, this would need to be consistent with the requirements in RfG.

1.14 RfG only specifies voltage ranges incumbent on Type D Power Generating Modules. The Workgroup discussed this issue and agreed that the voltage ranges applicable to Type A – C Power Generating Modules should adopt current GB practice. It is acknowledged that these voltage ranges are already broadly consistent with current GB requirements other than the voltage range between 132kV and 110kV. In GB voltage ranges of ±10% are permitted at 132kV or above and below 132kV voltage ranges of ±6% are permitted. Under RfG, the ±10% limit applies down to 110kV and above. The practical relaxation of this requirement in GB however is believed to have no impact.

1.15 Under RfG, only Offshore AC connected generators are within scope, with DC connected Power Park Modules being addressed under the HVDC code. RfG covers two forms of Offshore AC connection, these being a single onshore connection point between the Offshore Power Park Module and Onshore System (defined under RfG as Configuration 1) or a meshed Offshore AC connection which has two or more onshore grid connection points (defined under RfG as Configuration 2). These are covered in more detail as part of this consultation document.

1.16 GB is the only country in Europe which has an Offshore Transmission regime. Going forward, it is proposed to retain these arrangements but some amendments will be required to the requirements on Offshore Generators to ensure consistency with RfG. In terms of Offshore Power Park Modules connected via configuration 1, unity power factor (i.e. zero transfer of reactive power at the offshore connection point) is required. This is broadly equivalent to the current GB requirement although does not appear to allow for a wider reactive power capability range if agreed between the OFTO, NGET and Offshore Generator. In the case of AC connected Offshore Power Park Modules connected via configuration 2, a limited reactive power capability is permitted but this is quite narrow, broadly equating to 0.986 power factor lead to 0.986 power factor lag at rated MW output. Again there does not appear to be the opportunity to permit a wider reactive power capability if agreed between the OFTO, NGET and Offshore Generator. The voltage ranges are the same as those required Onshore and are not believed to pose a problem.

1.17 Table 1.17 below gives a high level comparison between the requirements in the GB Code, in RfG and any potential costs which could arise to developers.

| Generator Type | GB Code | RfG Requirement | Cost | Comments |
|---|---|---|---|---|
| Type A Power Generating Modules | Specified in G83/ G59 | Not applicable | Zero | RfG does not specify reactive capability or control performance requirements for Type A Power Generating Modules. |
| Type B Synchronous Power Generating Module (SPGM) | Specified by Network Operator in G59. For Large / Medium Plants which are Transmission Connected see requirements below | Reactive Capability specified by Network Operator. SPGM to be equipped with a permanent automatic excitation control system that can provide constant alternator terminal voltage control at a selectable setpoint | Negligible | Sufficient flexibility in Network Code and drafting to permit the Network Operator to define what requirement applies at the connection point. There will be a cost to implement the Generator Control Scheme via droop control but this is not believed to be significant from current practice |

| Generator Type | GB Code | RfG Requirement | Cost | Comments |
|---|---|---|---|---|
| Type B Power Park Module (PPM) | Specified by Network Operator in G59. For Large / Medium Plants which are Transmission Connected see below. | Reactive capability specified by Network Operator. RfG does not mandate voltage control, reactive power control or power factor control | Negligible | Code has sufficient flexibility for Network Operator to define requirement at Connection Point as per current requirements |
| Type C SPGM | Reactive capability is 0.85 PF lag to 0.95 PF lead at rated MW output at the Generator Unit Terminals. Each Generator to be fitted with a excitation control system and on load tap changer. Excitation System specifics defined in CC.A.6 of the Grid Code Connection Conditions. For Embedded connections the requirements are specified in G59 | Reactive Capability defined at the Connection Point as a combined voltage –Q/Pmax range rather than at the terminals. RfG silent on excitation performance requirements other than as per Type B Synchronous Power Generating Modules. | Negligible | As per current GB requirement other than the way in which the requirements are specified |
| Type C PPM | Reactive Capability of 0.95 Power Factor lead to 0.95 Power Factor lag at Rated MW output. In Scotland the reactive capability is specified at the HV side of the interconnecting Transformer. Voltage control is via a droop and setpoint characteristic | Reactive capability specified at the Connection point as a Voltage – Q/Pmax range. Voltage control, reactive power control or Power Factor Control can be specified by the Network Operator | Negligible | As per current GB requirement other than the way in which the requirements are specified. Settling time t2 will need to be changed from 1 second to 5 seconds. This change will have no material impact. |
| Type D SPGM | Reactive Capability and Voltage Control as per above entry for Type C Synchronous Power Generating Modules | Reactive Capability as per Type C SPGM's. Excitation Performance requirements specified similar to GB Grid Code other than the requirement for a Stator Current limiter | Negligible | As per current GB requirement other than the way in which the requirements are specified. There will be a requirement for Type D Power Generating Modules to provide details of their stator current limits which are currently not provided for in the Grid Code. This change is not expected to result in any significant cost. |
| Type D PPPM | As per above entry for Type C Power Park Modules. | As per above entry for Type C Power Park Modules. | Negligible | As per current GB requirement other than the way in which the requirements are specified |
| Configuration 1 AC Connected Offshore PPM | Zero transfer of reactive power at the LV side of the Offshore platform unless an alternative is agreed between NGET, the OFTO and the Generator | Zero transfer of reactive power at the Offshore Connection Point | Various – see comment section | RfG requirements do not provide for a wider reactive capability to be used at the Offshore Grid Entry Point as per current GB drafting. Potentially there could be additional costs as a result of this however it is believed that these costs could be mitigated by an appropriate commercial agreement backed up by a robust cost benefit analysis. |
| Configuration 2 AC Connected Offshore PPM | As per entry for Configuration 1 AC Connected Offshore PPM's | As per requirement for Type C and D Onshore Power Park Modules with a reduced Q/Pmax range | Not applicable | There are no projects currently planned in GB for this type of connection. Potentially there could be additional costs as a result of the restricted |

| | | | | |
|---|---|---|---|---|
| | | | | MVAr range however it is believed that these costs could be mitigated by an appropriate commercial agreement backed up by a robust cost benefit analysis. |

Table 1.17

1.18 It is acknowledged that there are two options currently being proposed for Banding. For the purposes of banding, most of the costs highlighted in the above table are believed to be negligible and therefore Banding is not believed to be significantly affected by these proposals.

1.19 In summary this report provides the following:

- Interpretation of the RfG voltage requirements including voltage range, reactive power capability and voltage control / reactive power control or power factor performance;
- The above requirements on Type B, C and D Power Generating Modules including those located Offshore;
- Proposed GB voltage related parameters;
- Differences between the current GB requirements and RfG with amendments introduced to ensure consistency with RfG;
- Additional costs that could arise from these proposals;
- Proposed legal drafting.

1.20 The key steps when forming the Grid Code legal drafting for EU requirements are:

- Duplicate full Grid Code sections where an anticipated change is required e.g. Connection Conditions – CCs);
- Mark this new section as EU-specific;
- Remove existing Grid Code text from this new section which is now superseded by the EU requirements;
- Update the new section with the newly draft EU-specific requirements.

1.21 The key steps when forming Distribution Code drafting for EU requirements are:

- The approach taken in forming the Distribution Code legal drafting is as follows;
- For new distribution connected generators it is currently proposed to replace the current ER G83 and ER G59 with two new documents of similar scope, ER G98 and ER G99. Both G98 and G99 will only apply to new connections;
- G59 and G83 will be retained as they will continue to apply to existing distribution connected generators;
- Make appropriate consequential amendments to the Distribution Code.

1.22 This consultation includes draft legal text for the application of voltage / reactive power capability requirements to Power Generating Modules which are of Type B or above – see Annex 2 – Annex 4. Annex 5 is the proposed legal text for section 9 of G99 to give stakeholders an idea of the structure of the document. It is not part of this consultation and comments are not required on this section of text. The specific technical contents of this document will be picked up as part of the other GC0048 RfG consultations.

1.23 It may be more appropriate, when the implications of all the EU Network Codes are better understood that the requirements on distribution connected generators are better incorporated into the body of the Distribution Code, rather than in the stand-alone documents G98 and G99. Stakeholder's views on this would be welcome at any time, and particularly in response to this consultation.

1.24 Linkage between the Distribution Code and Grid Code requires some co-ordination but at a high level it is envisaged that that the requirements for Type A and B Embedded Generators would reside in the Distribution Code and all other requirements (Type C – D Embedded Generators and all Transmission Connected Generators (Type A - D) would reside in the Grid Code. The linkage between Embedded Type C and Type D Power Generating Modules not caught by the requirements of the CUSC would be addressed by an approach similar to that for Licence Exempt Embedded Medium Power Stations (LEEMPS). The full details of this linkage will be developed over the coming months and introduced as part of the final implementation of RfG.

1.25 The GC0048 Workgroup believes these proposals are consistent with the RfG requirements and they provide adequate information for which Users can design their Plant and Apparatus.

1.26 The draft legal text in Annex 2 shows the proposed changes to the Grid Code Connection Conditions and the proposed format. Annex 3 highlights key points raised as part of the Grid Code legal text drafting.

1.25 The draft legal text in Annex 4 shows the proposed text to be adopted in Engineering Recommendation G99, to apply to Type B Power Generating Modules connected to distribution systems. Engineering Recommendation G99 will replace the existing Engineering Recommendation G59.

1.25 The draft legal text in Annex 5 is the proposed text for the complete G99 Section 9, "Network Connection Design and Operation", to apply to Type A and Type B Power Generating Modules connected to distribution systems. This has been provided to show the context of Annex 4 text. For the avoidance of doubt, Annex 5 is for information only and comments are not required on this section of text.

1.26 Based on the findings of the Workgroup discussions and Stakeholder engagement, the GC0048 Workgroup recommends that the Grid Code and Distribution Code (G99) are changed to include the modifications proposed in Annex 2 and 4 of this report.

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## 2 Why Change? Background to the Third Energy Package and Requirements for Generators (RfG) code

### What is ‘Requirements for Generators’?

2.1 RfG sets harmonised rules for grid connection across Europe of power generation modules of 800 Watts (W) in capacity or greater. It seeks to provide 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.

2.2 ENTSO-E web page for RfG, including code text: http://networkcodes.entsoe.eu/connection-codes/requirements-for-generators/

2.3 ENTSO-E overview of the European Network Codes: https://www.entsoe.eu/major-projects/network-code-development/Pages/default.aspx

### How did it originate?

2.4 The European Third Energy Package was adopted in July 2009, and has been law since March 2011. It is a suite of legislation for both Electricity and Gas, and is a key step forward in developing a more harmonised European energy market.

2.5 As applied to the electricity supply industry, the Third Energy Package has three key outputs: enhancing sustainability and helping the European Union (EU) meet its decarbonisation obligations; ensuring security of supply in light of a changing generation mix; and creating a single European Market for Electricity.

2.6 As is common to all EU law, regulations apply directly to the member states, whereas directives require transcription into national law. In particular, Directive 2009/72/EC (concerning common rules for the internal market in electricity) was transcribed into GB Law via The Electricity and Gas (Internal Markets) Regulations 2011.

2.7 The Third Energy Package also delivered the formation of the European Network of Transmission System Operators for Electricity and Gas; ENTSO-E/ENTSO-G. ENTSO-E led the drafting of the RfG before the text was approved by EU Member States in June 2015.

### When does it apply?

2.8 RfG ‘Entered Into Force’, the formal ratification of the legislation into the Official Journal of the European Union, on 17th May 2016. Member States then have two years to implement the code’s requirements nationally.

2.9 However, there is a point three years after Entry Into Force where new power generating modules will either be bound by existing national requirements, or the new RfG requirements. If a power generating module developer has a legally binding contract to procure their main plant items dated before two years after Entry Into Force, then they are classed as existing and current national requirements will apply. After this date, the user is classed as ‘New’ and must comply with RfG.

**Insert Heading**

Use this column in a Q&A style for explanations, in order to preserve the flow of the main text.

## What were ENTSO-E's objectives when drafting RfG?

2.10 ENTSO-E's brief when drafting these codes was to realise the broad objectives of the Third Energy Package. ENTSO-E also considered the challenges additional renewable generation would present to the way Transmission Systems are designed and managed. In a world of increasing wind and solar generation, HVDC interconnection and reliance on solid state power conversion technologies security of supply issues become an increasingly important consideration. Even if RfG was not mandating a need for change, it is expected that similar requirements would need to be introduced at a GB level alone simply to ensure the maintenance of a safe, secure, economic and flexible system.

2.11 From a systems engineering approach, ENTSO-E believe that Transmission Systems and their users (power generating modules, DSOs and demand facilities) should be considered as 'one system' comprehensively. They should co-operate closely during normal and disturbed operating conditions in order to preserve or restore system security.

## Determining significance

2.12 In particular, power generating modules are fundamental to the design and operational characteristics of the electricity system, playing an important role by providing ancillary services for system balancing/frequency control, voltage control, resilience during disturbances and to assist with system restoration after blackouts

2.13 RfG therefore specifies power generating module capabilities in this 'system operability' context, strives to be technology neutral and focuses primarily on capacity and connection requirements.

2.14 Article 2 of RfG defines power generating modules and related terms as "either a Synchronous Power-generating module or a power park module".

## Generator Banding

2.15 RfG uses four incremental types ('A' to 'D') which set a sliding scale of generator technical capabilities to support System Operators. The Transmission System Operation Guideline (TSOG) also uses the RfG banding thresholds to apply data exchange requirements on new *and* existing power generating modules (other EU codes may also refer to RfG banding too).


2.16 Each of the four RfG types has an associated connection voltage and installed unit capacity range (MW). For each European synchronous area, MW ceiling levels are set out in RfG. The code also describes the process each Member State needs to follow to set their levels (whether this is the ceiling level itself, or values below). A full cost benefit analysis is not mandated as part of this activity.

2.17 Any banding level proposals must be justified, consulted on, and finally approved by the appropriate National Regulatory Authority (NRA). In the event that Modifications to the approved levels are required in future, the same process can be re-run no sooner than 3 years later.

| | **Type A** | **Type B** | **Type C** | **Type D** |
|---|---|---|---|---|
| **Connection Voltage:** | <110kV | <110kV | <110kV | ≥110kV |
| | **MW range for Power Generating Modules** | **MW range for Power Generating Modules** | **MW range for Power Generating Modules** | **MW 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+ |

2.18 For GB, there are two proposed options for the banding level which have been formed following Industry Consultation, although it is acknowledged further dialogue continues with stakeholders in this area.

| Type | Option 1 - High | Option 2 - Medium |
|---|---|---|
| **A** | 800W – 1MW | 800W -1MW |
| **B** | 1-50MW | 1-10MW |
| **C** | 50-75MW | 10-50MW |
| **D** | 75MW | 50MW+ |

# 3 Background – Reactive Capability and Voltage Management

3.1 The power system comprises of a Transmission Network and Distribution Networks. At its most fundamental level, power stations would be connected directly to the Transmission System adjacent to their primary energy source (traditionally this being coal, gas, oil, nuclear or wind etc.) The transmission system would then transfer this bulk power across the system at high voltage (to minimise losses) for onward transfer to distribution systems to the end consumer.

3.2 It was traditionally rare for generation to connect directly to the distribution system, largely on the basis that plants and technological developments at that time sought to encourage economies of scale and that it was more economical to have a few large plants rather than a large volume of smaller plants. This was at a time before concerns over climate change and the developments of smaller and cleaner generation technologies.

3.3 At this time the majority of generation comprised of synchronous generation whose primary purpose to supply active and reactive power (MW) to the transmission system. However the need for voltage control is an essential requirement as without the maintenance of an adequate voltage profile across the system, the transfer of active power cannot take place. Traditionally, it has been the synchronous generator that has provided this capability.

3.4 A natural capability of a synchronous generator is that by varying the field voltage, the change in excitation results in a change in output of reactive power which in turn contributes to the control of network voltage. For a synchronous generator, adjustments to the excitation (i.e. the field voltage) between the under excited mode of operation (i.e. import of reactive power) to the overexcited mode of operation (export of reactive power) across all Generators, enables network voltage to be controlled within the limits of the SQSS for all system operational conditions (i.e. summer / winter – peak demand and minimum demand). To assist in controlling network voltage other facilities such as fixed reactive compensation devices such as capacitors / reactors or dynamic elements such as Static VAr Compensators or STATCOMs can be used at strategic locations. Unlike Active Power (MW), which can be transported across the network in bulk, reactive power (MVAr) transfer is limited due to the high impedance of the network. As such, the provision of reactive power support needs to be supplied locally at strategic points across the system.

3.5 Voltage support is therefore vital for the following reasons:

a) Protect plant and equipment from damaging over voltages,
b) Facilitate export and transfer of active power,
c) Maintain adequate voltage quality at the point of connection to customers,
d) Maintain voltage stability and transient stability,
e) Provide dynamic support of the system,
f) Assist in securing the system during and after grid system faults.

3.6 It is some 15 years since the first larger scale (50MW plus) wind farms started to connect to the GB Transmission and Distribution Systems. Unlike conventional thermal or hydro plant, which are based on synchronous generator technologies, wind generators are based on induction generators, often coupled with power electronic converters. The behaviour of these machines are very different to their synchronous counterparts. Notwithstanding this, the need for voltage control and reactive power support still remain a fundamental perquisite for the operation of any power system and as such the requirement for non-synchronous generation to contribute to voltage support is vital, even though these requirements are specified in a very different way to their synchronous counterparts.

3.7 These concepts are discussed in more detail later in this consultation. In general, the RfG for Type C and D Generators map to the GB requirements but the way in which these requirements are articulated is very different. It is considered that for Type C and Type D Power Generating Modules the GB requirements are simply translated into the form required under RfG.

3.8 For Type B Power Generating Modules, the requirements are largely dictated by the Network to which the Generator is connected.

3.9 RfG does not specify any requirements for Type A Power Generating Modules therefore any requirements applying to such plant would be specified only through National Governance arrangements.

# 4 Voltage Range

## Voltage Ranges

4.1 RfG Article 16(2)(a) Tables 6.1 and 6.2 (reproduced below) defines the steady state voltage operating range for Type D Power Generating Modules. CC.6.1.4 of the Grid Code however defines the steady state operating range of all Users' connected to the Transmission System and the ESQCR defines the voltage ranges for customers connected to Distribution Networks which are consistent with those values in the Grid Code.

*Table 6.1*

| Synchronous area | Voltage range | Time period for operation |
|---|---|---|
| Continental Europe | 0,85 pu-0,90 pu | 60 minutes |
| | 0,90 pu-1,118 pu | Unlimited |
| | 1,118 pu-1,15 pu | To be specified by each TSO, but not less than 20 minutes and not more than 60 minutes |
| Nordic | 0,90 pu-1,05 pu | Unlimited |
| | 1,05 pu-1,10 pu | 60 minutes |
| Great Britain | 0,90 pu-1,10 pu | Unlimited |
| Ireland and Northern Ireland | 0,90 pu-1,118 pu | Unlimited |
| Baltic | 0,85 pu-0,90 pu | 30 minutes |
| | 0,90 pu-1,118 pu | Unlimited |
| | 1,118 pu-1,15 pu | 20 minutes |

The table shows the minimum time periods during which a power-generating module must be capable of operating for voltages deviating from the reference 1 pu value at the connection point without disconnecting from the network, where the voltage base for pu values is from 110 kV to 300 kV.

*Table 6.2*

| Synchronous area | Voltage range | Time period for operation |
|---|---|---|
| Continental Europe | 0,85 pu-0,90 pu | 60 minutes |
| | 0,90 pu-1,05 pu | Unlimited |
| | 1,05 pu-1,10 pu | To be specified by each TSO, but not less than 20 minutes and not more than 60 minutes |
| Nordic | 0,90 pu-1,05 pu | Unlimited |
| | 1,05 pu-1,10 pu | To be specified by each TSO, but not more than 60 minutes |
| Great Britain | 0,90 pu-1,05 pu | Unlimited |
| | 1,05 pu-1,10 pu | 15 minutes |
| Ireland and Northern Ireland | 0,90 pu-1,05 pu | Unlimited |
| Baltic | 0,88 pu-0,90 pu | 20 minutes |
| | 0,90 pu-1,097 pu | Unlimited |
| | 1,097 pu-1,15 pu | 20 minutes |

The table shows the minimum time periods during which a power-generating module must be capable of operating for voltages deviating from the reference 1 pu value at the connection point without disconnecting from the network where the voltage base for pu values is from 300 kV to 400 kV.

4.2 Following RfG would create uncertainty between the steady state voltage requirements for a Type D Power Generating Module and Type A – C Power Generating Modules. Therefore, it seems appropriate to adopt the same approach as defined in CC.6.1.4 (which is also consistent with the requirements of the ESQCR) of the GB Grid Code accepting that CC.6.1.4 will require minor changes to ensure consistency with the European Codes. This issue is specifically raised as a Consultation question.

4.3 In general, CC.6.1.4 and RfG Article 16(a)(2) Tables 6.1 and 6.2 are the same, other than, the GB Code requires the voltage range applicable to User's connected below 132kV should be within ±6% and RfG requires Type D Power Generating Modules connected between 132kV and 110kV to remain within the limits of ±10%. It is not envisaged that this will have any significant impact on current GB practice as equipment rated at a nominal voltage of between 132kV and 110kV is generally not used.

4.4 RfG Article 16 (2)(b) does permit the relevant System Operator in co-ordination with the Generator and relevant TSO to specify wider voltage ranges or longer minimum operating times if economically and technically feasible. Under such conditions the Generator should not unreasonably without its agreement.

4.5 In addition, Article 16(2)(c) states that without prejudice to Article 16 (2)(c) the relevant System Operator in co-ordination with the Relevant TSO shall have the right to specify voltages at the connection point at which a Power Generating Module is capable of disconnection, with the terms and settings for automatic disconnection agreed between the relevant System Operator and the Generator which implies that narrower voltage ranges could be specified if agreed with the relevant System Operator with the relevant TSO.

4.6 As noted above it is worth emphasising that the Distribution Code does not specifically prescribe voltage and voltage ranges, falling back on the statutory values in ESQCR.

### Operational conditions for simultaneous overvoltage and underfrequency or simultaneous undervoltage and overfrequency

4.7 Article 16(2)(a)(ii) permits the Relevant TSO to specify shorter periods of time during which Type D Power Generating Modules shall be capable of remaining connected to the network in the event of simultaneous overvoltage and underfrequency or simultaneous undervoltage and overfrequency.

4.8 For Type C and Type D Power Generating Modules, both are subject to the same reactive capability, voltage and frequency range capability requirements. Noting also that it seems appropriate to apply the same voltage ranges (as per current GB practice) to Type A – C power generating modules. It therefore seems appropriate to apply this requirement to Type C and D Power Generating Modules.  A consultation question has therefore been raised in respect of this issue.

## 5 Summary of GB Grid Code Reactive Capability and control performance requirements for Synchronous Generating Units

5.1 Prior to consideration of the RfG reactive capability requirements it is first worth reviewing the GB Grid Code requirements. There are five primary sections of the Grid Code which are relevant to reactive power capability and control performance. For plant caught by the requirements of the Grid Code (in general, Generating Units which are either part of a Large or Medium Power Station) the following requirements apply:

CC.6.3.2 – Reactive Power Capability

CC.6.3.4 – Ability for the Reactive Power output to be fully available within the voltage range of ±5% at 400kV, 275kV and 132kV and lower voltages

CC.6.3.6 - Each Generating Unit must be capable of contributing to voltage control by continuous changes to the Reactive Power supplied to the System

CC.6.3.8 - Excitation and voltage control performance requirements

CC.A.6 – Performance requirements for continuously acting automatic excitation control systems for Onshore Synchronous Generating Units

5.2 In GB, CC.6.3.2 requires each Synchronous Generating Unit to be capable of continuous operation between the limits of 0.85 Power Factor lag to 0.95 Power Factor lead at the Generating Unit terminals when operating at Rated MW output.

5.3 CC.6.3.4 requires full reactive power capability for changes in the HV system voltage by ±5%. In other words, bearing in mind that that the reactive capability is specified at the Generating Unit terminals, this requirement is essentially defining the need for an on-load tap changer to be fitted to the generator transformer.

5.4 CC.6.3.6 defines the inherent relationship between reactive power and voltage.

5.5 CC.6.3.8 (a)(i) requires each Synchronous Generating Unit to be fitted with a continuously acting automatic excitation control system which is required to control the Synchronous Generating Unit without instability over the entire operating range. In general, it is common practice for the Automatic Voltage Regulator (AVR) to control the voltage to 1.0pu (i.e. its rated value) although CC.6.3.8(a)(v) does permit the Generator to control the terminal voltage in excess of 1.0pu where it may be desirable to do so. This may be advantageous to the Generator for example where the generator transformer has a limited number of taps, adjustment of the Generating Unit terminal voltage will permit a finer degree of MVAr import or export allowing a greater degree of control to the System voltage. Under BC2.A.2.6, Generating Units when instructed are required to achieve their target MVAr output to a tolerance of within ±25MVAr.

5.6 The corresponding performance requirements of the excitation system are covered in Grid Code CC.A.6 which covers requirements such as steady state voltage control, transient voltage control, power system stabilisers, under-excitation limiters, over excitation limitations. Site specific requirements such as ceiling voltage and rise time are currently specified in the Bilateral Agreement.

5.7 Under the Grid Code, it is common practice for all Synchronous Generating Units to operate in voltage control mode, with reactive power control or power factor control modes of operation being disabled unless otherwise specified (CC.6.3.8 (a)(vi)) in the Bilateral Connection Agreement.

5.8 All Generators who own Synchronous Generating Units will be required to submit their performance chart in accordance with the requirements of OC2.4.2.1 (a). This is effectively showing the MW and MVAr operating characteristics of the Generator at its terminals which is reproduced below in Figure 5.8.

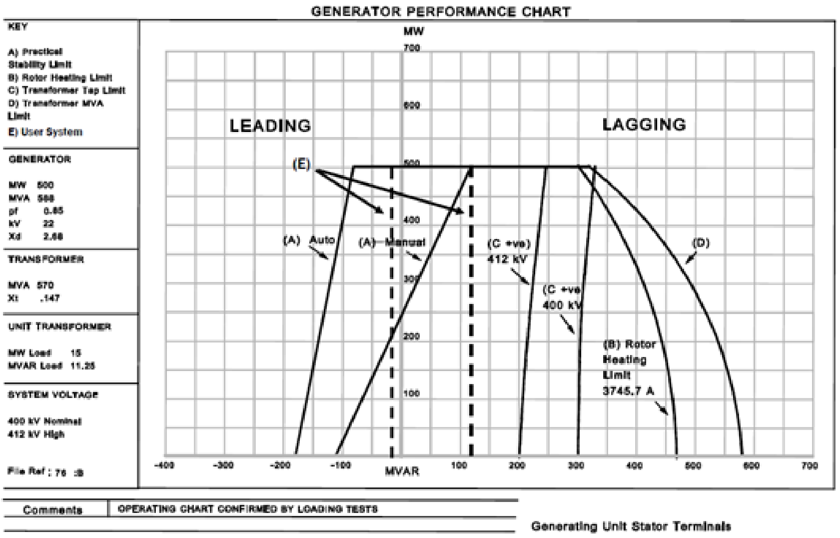


Figure 5.8 – Synchronous Generator Operating Chart

5.9 A typical connection of a Synchronous Generating Unit connected directly to the Transmission System is shown in Figure 5.9 below where Vg is the Generator voltage, Vs is the System Voltage and a is the tap ratio.

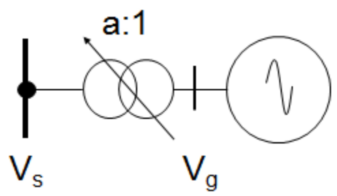


Figure 5.9 – Representation of a Synchronous Generator connected to the Transmission System

5.10 At the HV connection point the system voltage Vs is controlled by adjusting the tap position of the Generator transformer. The characteristics of the system voltage as a function of tap position are shown in Figure 5.10 below.

5.11 In practical terms control engineers at ENCC will issue MVAr instructions to the Generator. This instruction will require the Generator to change its MVAr output at the HV side of the Generator Transformer, for example change output from 0 MVAr output to 60 MVAr output. In response, the Generator will move the tap position which has the effect of changing the voltage at the terminals of the Generator; as a result, the AVR will adjust the terminal voltage back to its setpoint (e.g. 1.0pu) the effect of which is to export or import MVAr to or from the System. This effect is shown in Figure 5.11(a) and 5.11(b) below. It is important to note that without AVR action the desired effect would not be achieved.

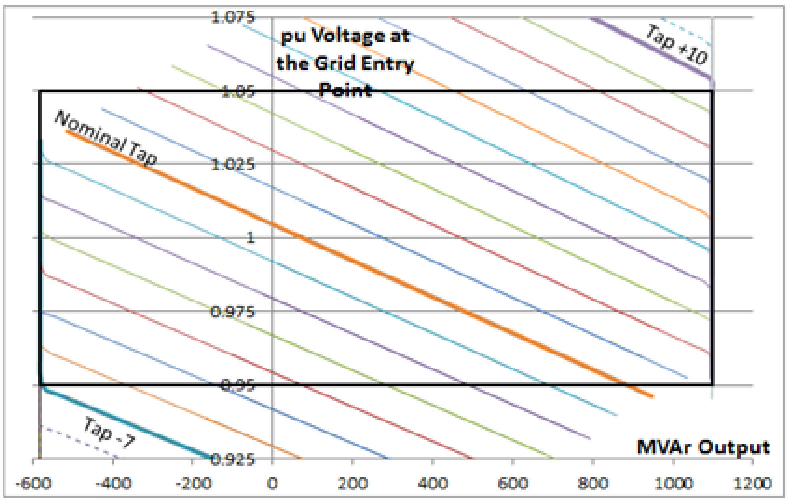


Figure 5.10 – HV Transmission System voltage variation against injected MVAr output as a function of tap position

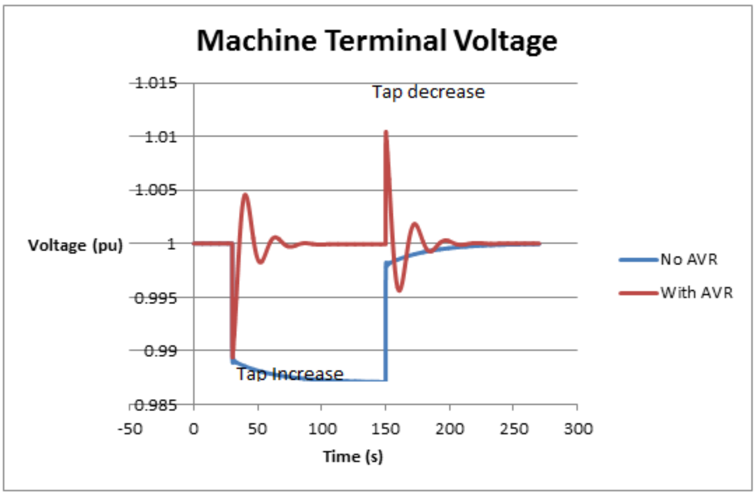


Figure 5.11(a) – Generator terminal voltage output with and without AVR action

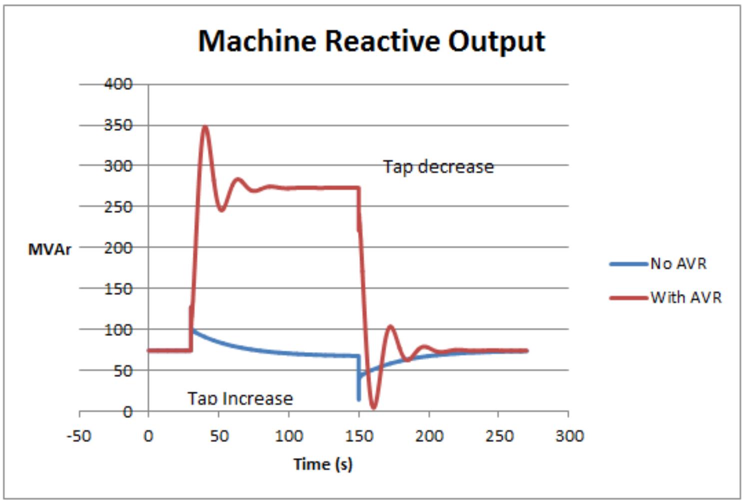


Figure 5.11(b) – Generator Reactive Power output with and without AVR action

5.11 The section above provides a high level overview of the principles of synchronous generator voltage control. If the reader is interested in more detailed information then it is recommended that reference [1] is consulted. Whilst the information above outlines the principle for voltage management for Synchronous Generating Units, an approach also used across the world is that the Generator transformer is fitted with an Offload tap and HV voltage control is managed by adjusting the terminal Setpoint Voltage of the Generating Unit.

5.12 For Embedded Synchronous Generating Units connected to the Distribution System which are caught by the requirements of the Grid Code (i.e. Large and Medium Power Stations) then the same requirements would apply as outlined above. It should however be noted Generators connected to the Distribution System would also need to satisfy the requirements of the Distribution Code and G59/3. For Large and Medium Power Stations the requirements specified in the Distribution Code and G59/3 are consistent with the Grid Code. For Small Embedded Power Stations the requirements of the Distribution Code and G59/3 and G83 would apply. In these cases, it is down to the DNO to define the requirements at the connection point, for example, CHP plants or Generation embedded in industrial networks where no onload tap changers are fitted and the desired point of voltage control is not at the terminals of the Generating Unit. In these cases, it is usual to employ droop control or line drop compensation. As an alternative, it may be preferential for the Network Operator to specify reactive power control or power factor control.

# 6 RfG Reactive Power capability and Control Performance requirements for Type C and Type D Synchronous Power Generating Modules

## Background to Reactive Power Capability and Control Performance

6.1 As summarised in section 3 above, the fundamental principles for power system voltage management are broadly the same although it is recognised that there are variations to the techniques that can be applied.

6.2 Under RfG, the reactive capability and voltage control requirements applicable to Synchronous Power Generating Modules are summarised as follows:-

| | |
|---|---|
| Article 17 (2)(b) - | Equipped with a permanent automatic excitation control system to provide constant alternator terminal voltage at a selectable setpoint without instability over the entire operating range of the synchronous power generating module. |
| Article 18(2)(a) – | Supplementary provision of Reactive Power at the connection point in respect of unusual connections. This issue is covered in section 6.9 below. |
| Article 18(2)(b) – | Reactive Power at maximum capacity |
| Article 18(2)(c) – | Reactive Power capability below maximum capacity |
| Article 19(2) – | Voltage control and excitation performance parameters. |

6.3 A full transcript of these Articles is reproduced in Annex 1 of this report, to enable the reader to compare the legal text of the RfG document with the interpretation and proposals suggested as part of this report.

6.4 Article 17 applies to Type B as well as Type C Synchronous Power Generating Modules. The issues relating to Type B Synchronous Power Generating Modules are described in more detail in section 7 of this report.

6.5 Article 18(2)(a) is a special case in point, which will be covered in section 6.19 of this report, when the general reactive capability and voltage control performance requirements have been discussed.

## Reactive Power Capability for Type C and D Synchronous Power Generating Modules

6.6 The Reactive Capability requirements for a Type C and D Synchronous Power Generating Module operating at maximum capacity are defined based on a U-Q/Pmax profile (i.e. a (voltage – reactive power)/Maximum Power Output profile) at the Connection Point. This is defined in Figure 7 of Article 18(2)(c) which is reproduced below in Figure 6.6.

6.7 In addition, Table 8 of RfG (Article 18(2)(b)) defines the parameters of the inner envelope of RfG Figure 7 for each Synchronous area. For GB, this has been set so that the maximum Q/Pmax range has been set at 0.95 and the maximum range of steady state voltage level in pu has been set at 0.225.

6.8 Under RfG it is the responsibility of the Relevant System Operator in coordination with the relevant TSO to specify the reactive power capability requirements against varying voltage when operating at maximum capacity. The U-Q/Pmax profile can take any shape but this should have regard to the potential costs of delivering the capability to provide reactive power at high voltages and reactive power consumption at low voltages.

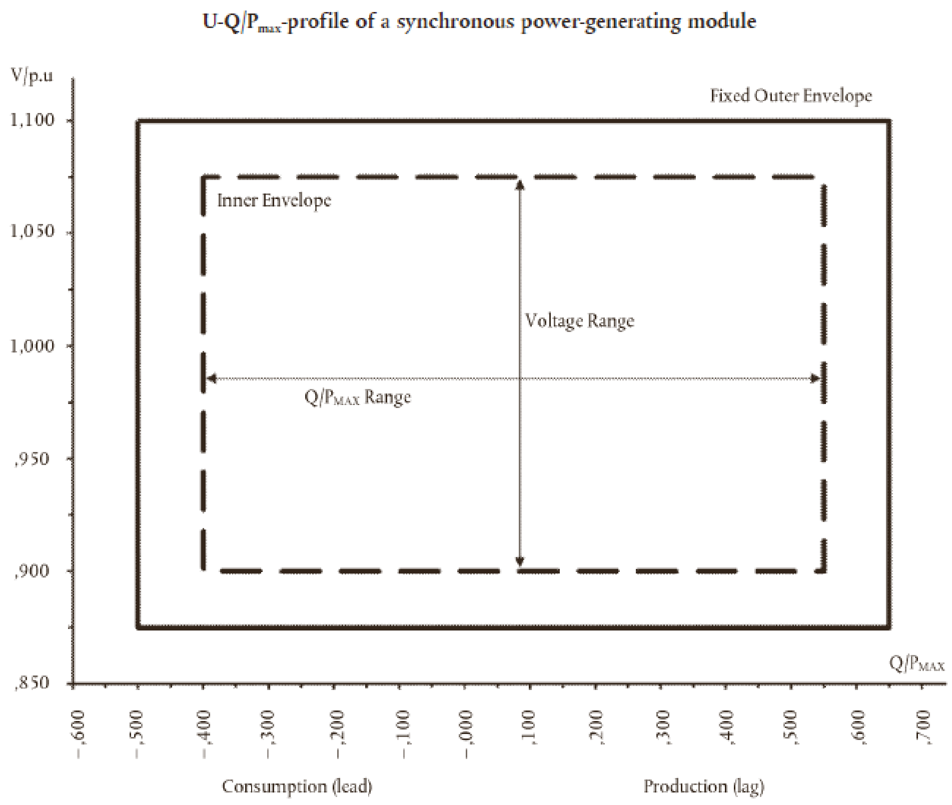


Figure 6.6 – Reproduction of Figure 7 of RfG (Article 18(2)(b))

6.8 Under RfG (Article 18(b)(2)(b)(ii)) the U-Q/Pmax profile specified by the relevant System Operator (as agreed in co-ordination with the Relevant TSO) shall not exceed the inner envelope or the maximum values specified in Table 8 (i.e. Q/Pmax of 0.95 / voltage range 0.225pu). In addition, the inner envelope can be at any position within Figure 7 so long as it does not breach the boundary of the fixed outer envelope. The inner envelope can take any shape. Where this is not rectangular, the voltage range specified by the Relevant Network Operator represents the highest and lowest values. The full reactive power range is therefore not expected to be available across the range of steady state voltages. In addition, all Type C and D Synchronous Power Generating Modules need to be capable of operating within the inner envelope to target values and timescales agreed with the relevant System Operator.

6.9 To summarise in bullet point form the general requirements are as follows;

- Reactive Capability and Voltage range are defined at the Connection Point.
- For GB the maximum Q/Pmax is set at 0.95 and voltage range is 0.225pu.
- The GB parameters specified in the RfG Table 8 cannot be exceeded.
- The inner envelope can be any shape and does not need to be rectangular. The inner envelope, nor should its position, exceed the outer envelope.
- The Synchronous Power Generating Module shall be capable of operating at any point within the inner envelope to a target value and appropriate timescales specified by the relevant System Operator.

6.10 These requirements are significantly different from the GB code which requires reactive capability to be supplied at the Generating Unit terminals. That said, the requirements applicable in GB can easily be translated into the RfG on a more or less like for like basis. The general approach adopted here is to apply the current requirements of the GB Grid Code unless there is good reason not to do so. In this case, as the RfG is applied at the connection point and it is specified as a u-Q/Pmax profile, it is a simple matter of translating the GB requirements into the format stipulated by RfG. At this point reference is made to Figure 6.10 below.

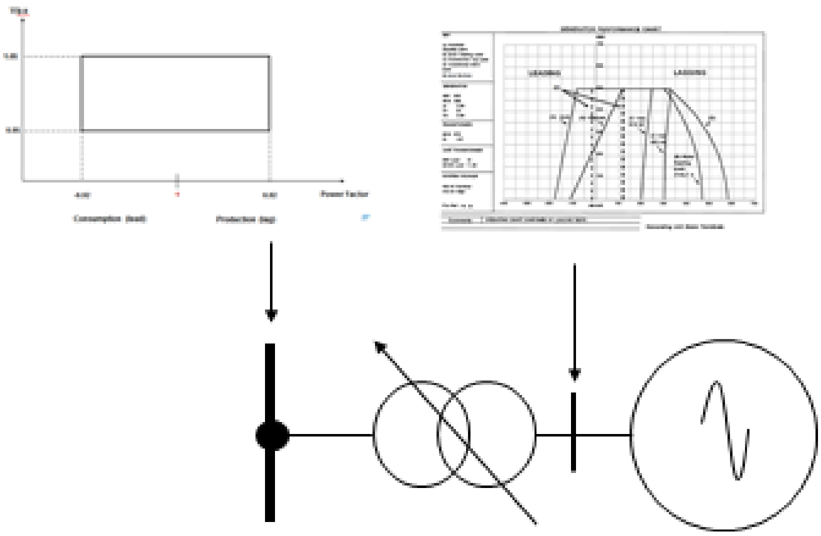

Figure 6.10 – GB Reactive Capability at the Generating Unit terminals and at the HV Connection Point

6.11 Under CC.6.3.2 of the GB Grid Code a reactive capability of 0.85 Power Factor Lag to 0.95 Power Factor Lead at the Generating Unit terminals is required at Rated MW output. In addition, CC.6.3.4 of the GB Grid Code requires the full reactive capability to be delivered by the Generating Unit at the Grid Entry Point (i.e. the HV Connection Point) for system voltage changes of ±5%.

6.12 On the other hand, RfG Article 18(2)(b) requires delivery of reactive power at the HV connection point over a specific voltage range, which in essence is simply a combination of CC.6.3.2 and CC.6.3.4. The translation of Power Factor into Q/Pmax is comparatively straight forward as shown below.

$$S = \sqrt{3}.VI$$
$$Q = \sqrt{3}\,VISin\varphi$$
$$P = \sqrt{3}\,VICos\varphi$$
$$Power\ \ Factor = \ Cos\varphi$$

$Dividing\ Q/P\ therefore\ gives\ the\ relationship\ between\ Q/P\ and\ Power\ Factor$

$$\frac{Q}{P} = \frac{\sqrt{3}\,VISin\varphi}{\sqrt{3}\,VICos\varphi} = Tan\varphi = Tan(arccos\varphi) = Tan(arcos\ (Power\ Factor))$$

6.13 Table 8 of RfG permits the GB Synchronous area to specify a maximum Q/Pmax range of 0.95. It is assumed and expected that at the HV Connection Point the same importing and exporting capability would be required (i.e. the capability is symmetrical) Based on the above equation this yields a maximum power factor range of:-

$$Maximum\,GB\ \ Q/Pmax\,range = 0.95$$
$$For\,Symmetrical\,operation = 0.95\ /\ 2\ \ = 0.45$$
$$For\,Symmetrical\,operation\ Q/Pmax\,range\ = 0.95\ /\ 2\ \ = 0.475$$
$$Giving\,a\,maximum\,Power\,Factor\,range\,of\ = Cos\,(arctan\,0.475) = \pm 0.903$$

6.14 In other words under RfG this would give a maximum power factor range of 0.903 Power Factor lag to 0.903 Power Factor lead at Rated MW output at the HV Connection Point. This provides the maximum range permitted under RfG. As to the GB value it is proposed to translate the current requirement of 0.85 Power Factor lag to 0.95 power factor lead at Rated MW output at the HV Connection Point. This translation will depend on the impedance of the Generator Transformer which could be anywhere between 10 – 20% on Transformer Rating, but taking these variations into account, a power factor range of 0.92 Power Factor lag to 0.92 Power Factor lead at Rated MW output at the HV Connection Point would be considered to be reasonable. This conclusion was also reached as part of the H/04 consultation which can be found in Appendix 2 section 5.4 of this reference [2].

6.15 RfG sets out the maximum voltage range in the GB synchronous area to 0.225. Under CC.6.3.4 of the GB Grid Code, full reactive power must be delivered by a Generating Unit over and HV voltage range of ±5%. Translating this on a like for like basis to the RfG Code sets this voltage range to a value of 0.1pu. With these values set, the proposed U-Q/Pmax profile is shown in Figure 6.15 below.

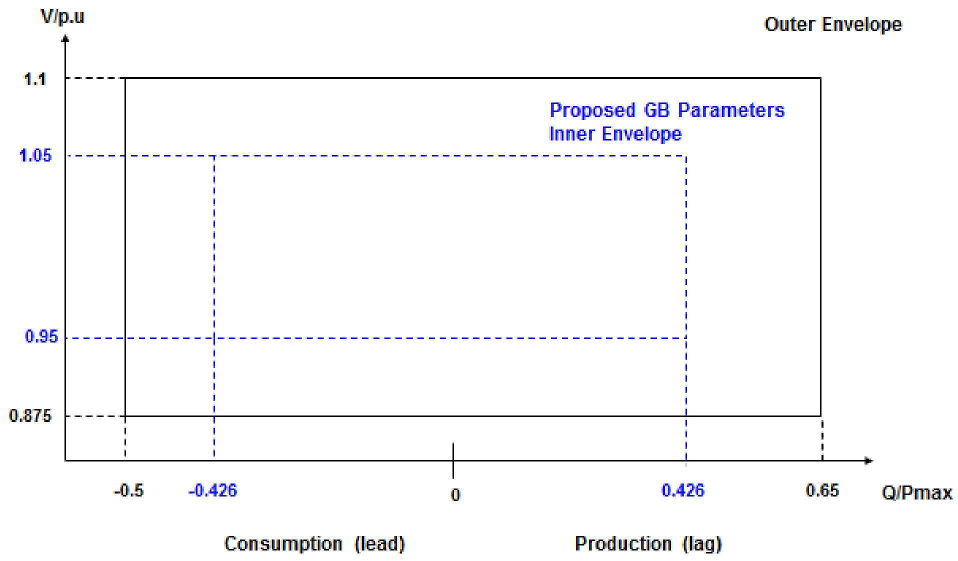


Figure 6.15 – Proposed GB U-Q / Pmax profile settings at Maximum Capacity

6.16 Article 18(2)(c) defines the requirements for Reactive Power Capability when operating below maximum capacity. In summary, RfG requires Type C and Type D Power Generating Modules to be capable of operating at every possible operating point in the P-Q capability diagram of the alternator of that Synchronous Power Generating Module at least down to the minimum stable operating level. At reduced active power output the reactive power supplied at the connection point needs to satisfy the P-Q capability diagram of the alternator of that Synchronous Power Generating Module taking the auxiliary supply power and the active and reactive power losses of the step up transformer into account.

6.17 The requirements of Article 18(2)(c) are difficult to interpret as it mixes the term Alternator and Synchronous Power Generating Module. The interpretation is that an Alternator is the same as the GB Grid Code definition of a Generating Unit and the Synchronous Power Generating Module is one or more Alternators plus other electrical equipment (e.g. Generator Transformer etc.) as seen at the Connection Point. Under RfG, the definition of a P-Q capability diagram is "a diagram describing the reactive power capability of a power-generating module in the context of varying active power at the connection point. It is expected that under an RfG Compliant Grid Code, Generators will also need to supply a Performance chart at the Connection Point in addition to the current GB requirements.

6.18 In addition to the above requirements, Article 18(2)(a) states "Type C synchronous power-generating modules shall fulfil the following additional requirements in relation to voltage stability: (a) with regard to reactive power capability, the relevant system operator may specify supplementary reactive power to be provided if the connection point of a synchronous power-generating module is neither located at the high-voltage terminals of the step-up transformer to the voltage level of the connection point nor at the alternator terminals, if no step-up transformer exists. This supplementary reactive power shall compensate the reactive power demand of the high-voltage line or cable between the high-voltage terminals of the step-up transformer of the synchronous power-generating module or its alternator terminals, if no step-up transformer exists, and the connection point and shall be provided by the responsible owner of that line or cable";

6.19 Article 18(2)(a) is an interesting case. As discussed above, RfG specifies the Reactive Capability at the Connection Point. In unusual circumstances where there is either no Generator Transformer or a long piece of line or cable between the Generator and the System, then this clause permits the Relevant System Operator to specify that the owner of the line or cable should install additional reactive compensation equipment to satisfy the requirements of Article 18(2)(b). This is unusual but could arise in the case of a private network or industrial complex which has an agreement with NGET or DNO at the connection point. A privately owned Generator then seeks a connection to that private network necessitating an increase in the reactive Capability at the Connection Point which the private network owner will have to facilitate. . An example of this situation is shown in Figure 6.6 below.

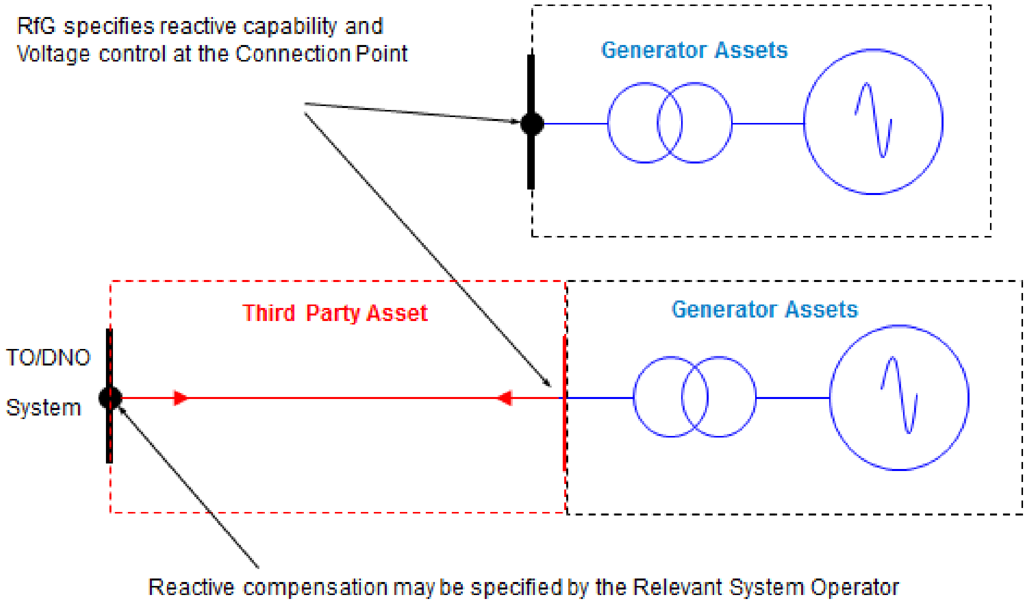


Figure 6.19 – Interpretation of RfG Article 18(2)(a)

## Excitation and Voltage Control Performance Requirements

6.19 Article 19(2) defines the excitation and voltage control performance requirements for Type D Synchronous Power Generating Modules. An extract of these requirements is reproduced in Annex 1. In summary these specify the following requirements:-

- Parameters and settings to be agreed between the Power Generating facility owner and Relevant System Operator in coordination with the Relevant TSO
- The requirements shall include specifications and performance of the Automatic Voltage Regulator, and Excitation System including steady state and transient performance.
- In addition the excitation control system shall include an Underexcitation limiter, an over excitation limiter and a stator current limiter. The bandwidth of the excitation system output signal shall be limited so as to prevent torsional oscillations on other power generating modules connected to the network.
- A Power System Stabiliser as specified by the relevant TSO.

6.20 In GB the excitation performance requirements are specified in CC.A.6 of the Grid Code. The GB requirements are broadly the same as those specified in RfG other than in respect of a Stator Current Limiter which will require amendment to the legal text. This issue has been accounted for and included in the revised legal text. A summary of the RfG requirements and the current GB obligations are summarised in Table 6.20 below.

| European Requirement | GB Requirement |
| --- | --- |
| Parameters and Settings including Transient and Steady State voltage control– (Art 19 (2)(a)&(b)) | Steady State and Transient Voltage Control parameters covered in CC.A.6.2.3 and CC.A.6.2.4 |
| Bandwidth limitation – (Art 19(2)(b)(i)) | Bandwidth limitation – (CC.A.6.2.5.5) |
| Under Excitation Limiter – Art 19(2)(b)(ii) | Under Excitation Limiter – (CC.A.6.2.7) |
| Over Excitation Limiter – Art 19(2)(b)(iii) | Over Excitation Limiter – (CCA.6.2.8) |
| Stator Current Limiter – Art 19(2)(b)(iv) | Not explicitly defined |
| PSS Function – Art 19(2)(b)(v) | Power System Stabiliser – (CC.A.6.2.5) |

Figure 6.20 – Comparison between RfG Excitation Performance Requirements and the current GB requirements

6.21 Under RfG the above voltage control and excitation performance requirements only apply to Type D Synchronous Power Generating Modules, yet the full reactive power capability requirements also apply to Type C Synchronous Power Generating Modules. The group discussed this issue and it was felt on balance that it would also be appropriate to apply the same requirements to Type C Synchronous Power Generating Modules on the basis that no significant additional cost would be attributable to this additional requirement in so far that similar principles already apply to Large and Medium Power Stations in GB. A consultation question has been raised in section 16 on this issue.

# 7 Reactive capability and control performance requirements for Type B Synchronous Power Generating Modules

## General Reactive Capability and control performance requirements applicable to Type B Synchronous Power Generating Modules

7.1 Type B Synchronous Power Generating Modules are subject to lesser requirements than their Type C and Type D counterparts which are defined on RfG Article 17(2).

7.2 RfG Article 17(2)(a) states “with regard to reactive power capability, the relevant System Operator shall have the right to specify the capability of a Synchronous Power Generating Module to provide reactive power”.

7.3 In addition RfG Article 17(2)(b) states “with regard to the voltage control system, a Synchronous Power Generating Module shall be equipped with a permanent automatic excitation control system that can provide constant alternator terminal voltage at selectable setpoint without instability over the entire operating range of the Synchronous Power Generating Module.

## Reactive Capability requirements applicable to Type B Synchronous Power Generating Modules

7.4 Taking reactive capability first, RfG effectively leaves this choice to the relevant System Operator this being either the Transmission System Operator (i.e. NGET) in respect of Transmission or the Distribution Network Operator in respect of a DNO’s network.

7.5 For a Transmission connected Synchronous Generating Unit, the current GB Grid Code practice would be for a reactive capability of 0.85 Power Factor Lag to 0.95 Power Factor Lead at Rated MW output at the Generating Unit terminals.

7.6 For a DNO connected Synchronous Generator which falls outside the requirements of the Grid Code, the reactive capability requirements are specified in the Distribution Code and G59/3. In general, this provides for a fair degree of flexibility. Traditionally when the volume of embedded generation was more limited, common practice tended to promote Power Factor Control. As the volume of Embedded Generation has risen substantially over recent years, the move to a reactive capability and voltage control performance requirement has become more important for two reasons i) the need to manage voltage profile on the DNO networks and ii) it is often cheaper from a connection point of view for the Generator to have a voltage control capability than fixed power factor control.

7.7 Notwithstanding the points raised in paragraph 7.6 above, there will be cases, for example, Generators embedded within industrial networks connected to strong sections of the DNO network where the need for power factor control or reactive power control is more appropriate. This would clearly be specified on a case by case basis by the Distribution Network Operator.

7.8 Therefore, to ensure the requirements remain as flexible as possible, it is proposed that Type B Synchronous Power Generating Modules would be required to have a reactive capability range of 0.95 Power Factor lag to 0.95 Power Factor lead at Rated MW output at the Connection Point unless otherwise agreed with NGET or the relevant Distribution Network Operator. This then enables the Relevant System Operator to have maximum flexibility in defining its requirements at the connection point.

7.9 The value of 0.95 Power Factor Lead to 0.95 Power Factor lag at Rated MW output has been selected on the basis of DNO requirements, general plant capability and equitable treatment with Power Park Modules.

## Control Performance requirements applicable to Type B Synchronous Power Generating Modules

7.10 In respect of voltage control, Article 17(2)(b) requires Type B Synchronous Power Generating Modules to be equipped with a permanent automatic excitation control system that can provide constant alternator terminal voltage at a selectable setpoint without instability over the entire operating range. In this context it is assumed that the entire operating range covers zero MW to Rated MW over the full reactive capability range (i.e. maximum lag (underexcited) to maximum lead (overexcited).

7.11 It is common practice for any Synchronous Generator to be fitted with these facilities as an inherent capability. Where this becomes more of an issue is where the Generator forms part of industrial or private network and the Relevant System Operator requires a capability and performance requirement at the connection point, yet the Generator has to have the capability to control terminal voltage in line with RfG Article 17(2)(b). The key issue here is that whilst the Generator may be fitted with the capability required by Article 17(2)(b), practical implementation of a scheme would be dependent upon the requirement specified at the Connection Point by the Relevant Network Operator which could be voltage control, power factor control or reactive power control. A representation of a typical example is shown in Figure 7.11 below.

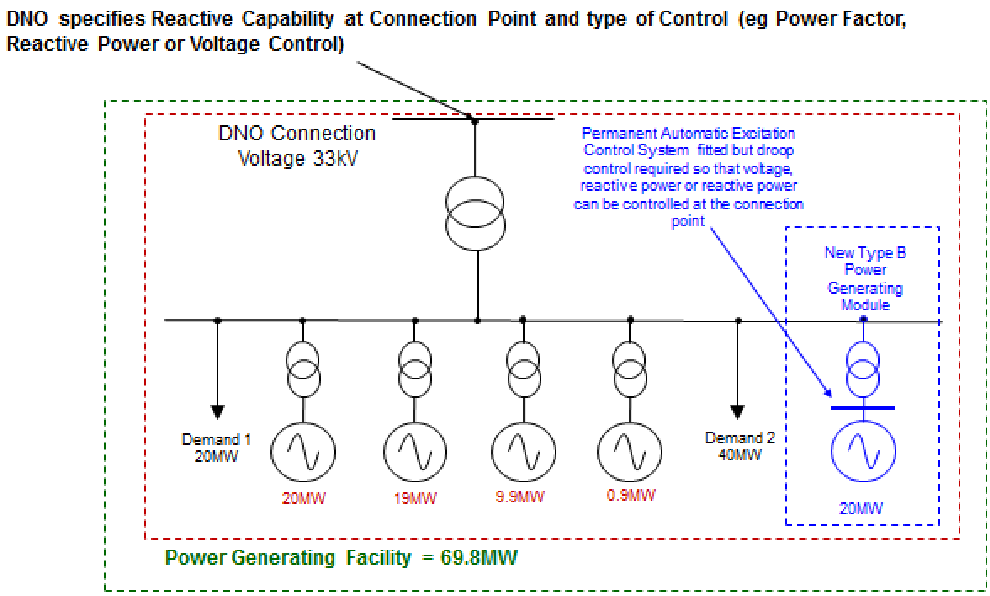


Figure 7.11 – Representation of a new Type B Synchronous Power Generating Module embedded within a private network with the control type and reactive capability specified at the Connection Point by the Relevant Network Operator.

7.12 In the example shown in Figure 7.11, the Relevant System Operator would then need to specify the reactive capability and type of control required at the connection point. If for example, the relevant System Operator required a reactive capability of 0.95 power factor lead to 0.95 power factor lag at the connection point with voltage control at the same place, then a control scheme would need to be implemented utilising line drop (i.e. droop) compensation to cater for this functionality. The Generating Unit would still have the capability defined in Article 17(2)(b) but the excitation system is being controlled (via line drop compensation) to contribute to voltage control at the Connection Point. Clearly a sensible position would need to be agreed between the Network Operator and Generator so that an unreasonable burden is not placed on solely on the new Generator.

7.13 Therefore, to enable maximum flexibility the Grid Code and Distribution Code need to be worded appropriately. To summarise, it is proposed that any Type B Synchronous Power Generating Module connected to the Transmission System would need to satisfy the same general requirements as a Type B Synchronous Power Generating Module connected to the Distribution Network, with any site specific requirements being specified in the Connection Agreement therefore allowing alternative control strategies to be employed.

7.14 In general each Type B Synchronous Power Generating Module will be required to be equipped with a permanent automatic excitation system that can provide constant alternator terminal voltage at a selectable setpoint without instability over the entire operating range of the Type B Synchronous Power Generating Module. In addition, the relevant System Operator will specify in the Connection Agreement if the control system of the Type B Synchronous Power Generating Module shall contribute to voltage control or Reactive Power control or Power Factor control at the Connection Point (or other defined busbar). The performance requirements of the control system including droop (where applicable) shall be specified in the Connection Agreement.

# 8 RfG Reactive Power capability and Control Performance requirements for Type C and Type D Power Park Modules

## Background

8.1 Under RfG, the reactive capability and voltage control requirements applicable to Power Park Modules are summarised as follows:-

| | |
|---|---|
| Article 21(3)(a) – | Supplementary provision of Reactive Power at the connection point in respect of unusual connections. This issue is covered in section [8.4] below. |
| Article 21(3)(b) – | Reactive Power at maximum capacity |
| Article 21(3)(c) – | Reactive Power capability below maximum capacity |
| Article 21(3)(d) – | Reactive Power control modes of operation. |

8.2 A full transcript of these Articles is reproduced in Annex 1 of this report, to enable the reader to compare the legal text of the RfG document with the interpretation and proposals suggested as part of this report.

8.3 The issues relating to Type B Power Park Modules are described in more detail in section 9 of this report.

8.4 RfG Article 21(3)(a) covers the situation where a Power Park Module may be connected if the connection point of a Power Park Module is neither located at the high-voltage terminals of the step-up transformer to the voltage level of the connection point nor at the convertor terminals, if no step-up transformer exists. This supplementary reactive power shall compensate the reactive power demand of the high-voltage line or cable between the high-voltage terminals of the step-up transformer of the power park module or its converter terminals, if no step-up transformer exists, and the connection point and shall be provided by the responsible owner of that line or cable. This issue is exactly the same as that outlined for

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Use this column in a Q&A style for explanations, in order to preserve the flow of the main text.

Synchronous Power Generating Modules which is covered in paragraphs 6.18 and 6.19 above. The legal text in Annex 2 has been updated to reflect this requirement with a typical arrangement shown in Figure 8.4 below.

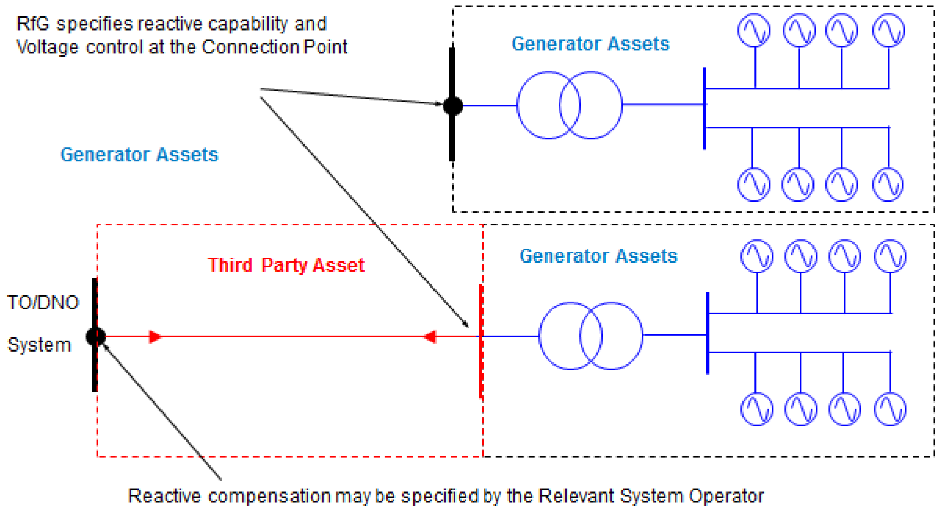



Figure 8.4 – Interpretation of RfG Article 21(3)(a)

## Reactive Power Capability for Type C and D Power Generating Modules

8.5 The Reactive Capability requirements for a Type C and D Power Park Modules operating at maximum capacity are defined based on a U-Q/Pmax profile (i.e. a (voltage – reactive power)/Maximum Power Output profile) at the Connection Point. This is defined in Figure 8 of Article 21(3)(b) which is reproduced below in Figure 8.5. These principles are similar to those applied to Synchronous Power Generating Modules which are summarised in Section 6 above.

8.6 In addition, Table 9 of RfG (Article 21(3)(b)) defines the parameters of the inner envelope of RfG Figure 8 for each Synchronous area. For GB, this has been set so that the maximum Q/Pmax range has been set at 0.66 and the maximum range of steady state voltage level in pu has been set at 0.225.

8.7 Under RfG it is the responsibility of the Relevant System Operator in coordination with the relevant TSO to specify the reactive power capability requirements against varying voltage when operating at maximum capacity. The U-Q/Pmax profile can take any shape within the boundaries of which the Power Park Module shall be capable of providing reactive power at its maximum capacity.

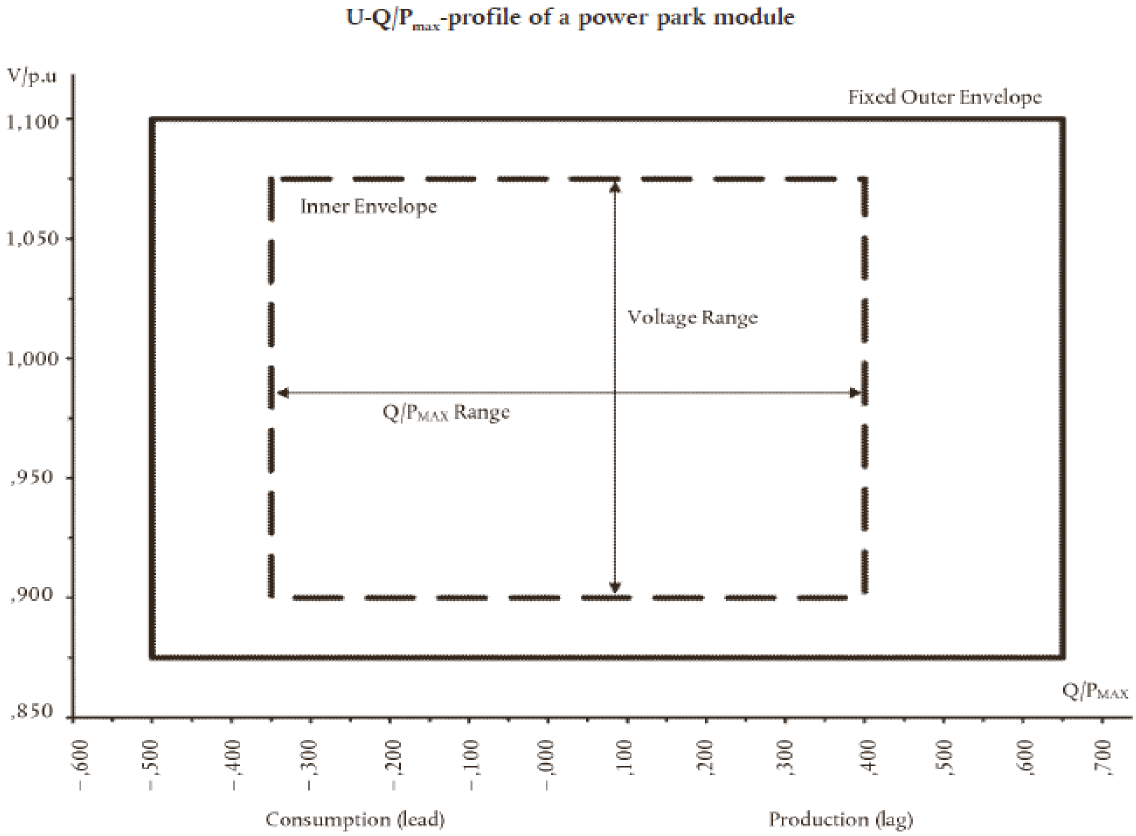



Figure 8.5 – Reproduction of Figure 8 of RfG (Article 21(3)(b))

8.8 Under RfG (Article 21(3)(b)(ii)) the U-Q/Pmax profile specified by the relevant System Operator (as agreed in co-ordination with the Relevant TSO) shall not exceed the inner envelope or the maximum values specified in Table 9 (i.e. Q/Pmax of 0.66 / voltage range 0.225pu). In addition, the inner envelope can be at any position within Figure 8 so long as it does not breach the boundary of the fixed outer envelope. The inner envelope can take any shape having regard to the potential costs of delivering the capability to provide reactive power production at high voltages and reactive power consumption at low voltages. Where this is not rectangular, the voltage range specified by the Relevant Network Operator represents the highest and lowest values. The full reactive power range is therefore not expected to be available across the range of steady state voltages.

8.7 To summarise in bullet point form the general requirements are as follows:

- Reactive Capability and Voltage range defined at the Connection Point;
- For GB the maximum Q/Pmax is set at 0.66 and voltage range is 0.225pu;
- The GB parameters specified in RfG Table 8 cannot be exceeded;
- The inner envelope a can be any shape and does not need to be rectangular. The inner envelope, nor should its position, exceed the outer envelope.

8.8 These requirements are more similar to the GB Grid Code requirements for Power Park Modules compared to their synchronous counterparts. That said there are still some significant differences between RfG and the GB Code. As with Synchronous plant, the general approach adopted here is to apply the current requirements of the GB Grid Code unless there is good reason not to do so. In this case, as the RfG requirement is applied at the connection point and it is also specified as a u-Q/Pmax profile so it is a simple matter of translating the GB requirements into the format stipulated by RfG. At this point reference is made to Figure 8.8 below.

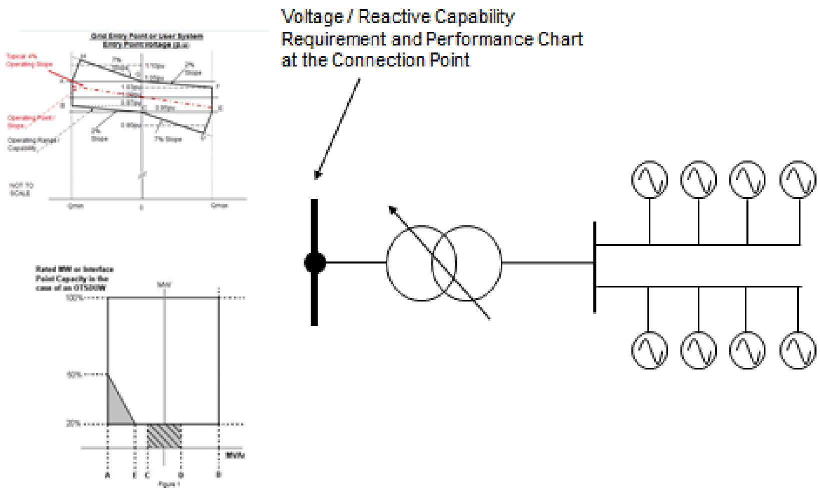



Figure 8.8 – GB Voltage / Reactive Capability and Performance Chart at the Grid Entry Point for a Power Park Module

8.9 Under CC.6.3.2 of the GB Grid Code, a reactive capability of 0.95 Power Factor Lag to 0.95 Power Factor Lead at the Grid Entry Point (or User System Entry Point if Embedded) is required at Rated MW output. In Scotland this requirement is specified at the HV side of the 132kV/33kV, 275kV/33kV or 400kV/33kV transformer rather than at the Grid Entry Point or User System Entry Point. In addition, CC.6.3.4 of the GB Grid Code requires the full reactive capability to be delivered by the Power Park Module at the Grid Entry Point (i.e. the HV Connection Point) or (User System Entry Point if Embedded) for system voltage changes of ±5%. Under CC.6.3.4 of the Grid Code a relaxation to the voltage / reactive capability requirements for any embedded or directly connected Power Park Modules connected to the System at 33kV or less. For Type C and Type D Distribution connected Power Park Modules it is anticipated the Distribution Code will define the requirements through the Grid Code similar to the approach adopted for Licence Exempt Embedded Medium Power Stations (LEEMPS). For Type B Power Park Modules connected to the Distribution System these issues are covered in more detail in section 8.22 below.

8.10 The requirements in Article 21 of RfG Article 21(3)(b) also specify a combined reactive capability and voltage range requirement at the Connection Point in a similar way to that for Synchronous Power Generating Modules. Again, this would merge the requirements of CC.6.3.2 and CC.6.3.4 but the advantage here is that the GB Grid Code already defines the requirements at the Connection Point rather than at the terminals of each Power Park Unit. The translation of Power Factor into a Q/Pmax form is the same process as that described in section 6.12 above.

$$\frac{Q}{P} = \frac{\sqrt{3}\,VISin\varphi}{\sqrt{3}\,VICos\varphi} = Tan\varphi = Tan(arccos\varphi) = Tan(arcos\,(Power\ Factor))$$

8.11 Table 9 of RfG permits the GB Synchronous area to specify a maximum Q/Pmax range of 0.66. Based on the above equation this yields a maximum power factor range of:-

$$Maximum\ GB\ \ Q/Pmax\ range = 0.66$$
$$For\ Symmetrical\ operation = 0.66\ /\ 2\ \ = 0.33$$

$$\textit{For Symmetrical operation } Q\ /\ \textit{Pmax range} = 0.66\ /2\ = 0.33$$
$$\textit{Giving a maximum Power Factor range of} = Cos\ (arctan\ 0.33) = \pm 0.95$$
$$\textit{In other words a power factor range of } 0.95\ \textit{lag to } 0.95\ \textit{lead at}$$
$$\textit{Rated MW output which is the same as the current GB requirement under CC.}\,6.3.2$$

8.12 When translating the GB Reactive Power Capability requirements into RfG, the current requirement of 0.95 Power Factor Lag to 0.95 Power Factor Lead at Rated MW output at the Connection Point equates to a Q/Pmax range of ±0.33 (i.e. the maximum value allocated to the GB Synchronous area). As mentioned under CC.6.3.4 of the GB Grid Code, full reactive power must be delivered by a Power Park Module over and HV voltage range of ±5%.

8.13 Unlike Synchronous Generating Units, Power Park Modules behave in a very different way, in particular their delivery of Reactive Power and contribution to Voltage Control. The principles of operation are based on a slope and setpoint characteristic, similar to that of an SVC. In this case the setpoint could be adjusted to anywhere between 0.95 and 1.05pu. The slope could be anywhere between 2% and 7% which effectively defines the complete operating envelope of the Power Park Module. In practice the setpoint of a Power Park Module would typically be adjusted to 1.0pu with a slope of 4% (the slope being that for a 4% change in voltage the reactive power output will change from unity to fully leading power factor or unity to fully lagging power factor). In practice, as the system voltage changes (due to load variations etc. and the voltage at the connection point moves away from 1.0pu voltage, the Power Park Module will either inject or absorb reactive power thereby returning the voltage back to 1.0pu. This operating characteristic is shown in Figure 8.13.

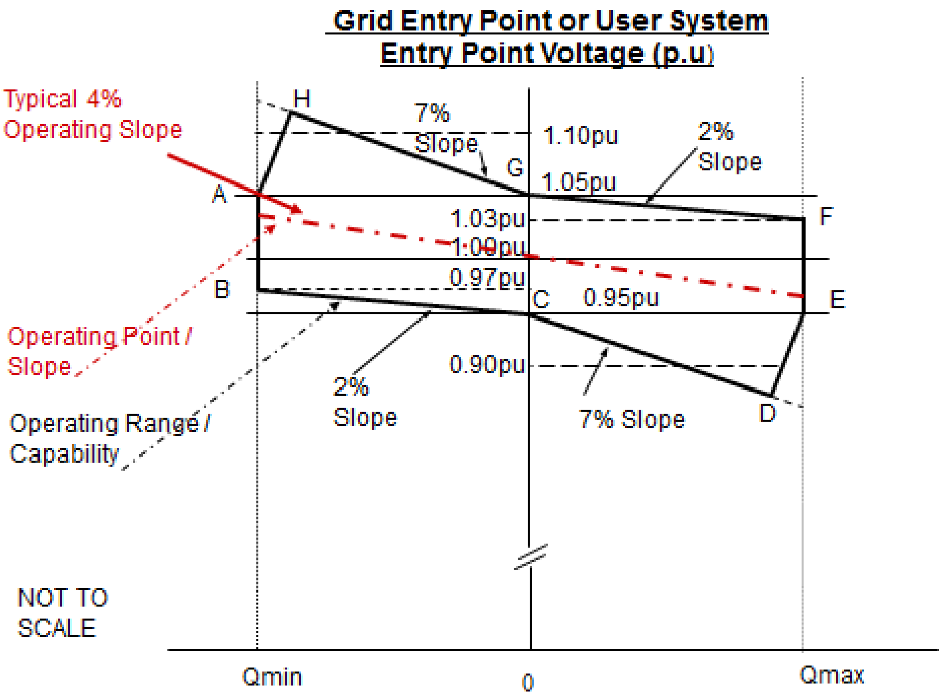



Figure 8.13 – Voltage / Reactive Capability Diagram of a Power Park Module as specified under CC.A.7.2.2.4 of the GB Grid Code

8.14 To transfer this requirement into the RfG Requirements it is a simple matter to translate this requirement into Figure 8 of RfG which is shown in Figure 8.14 below.

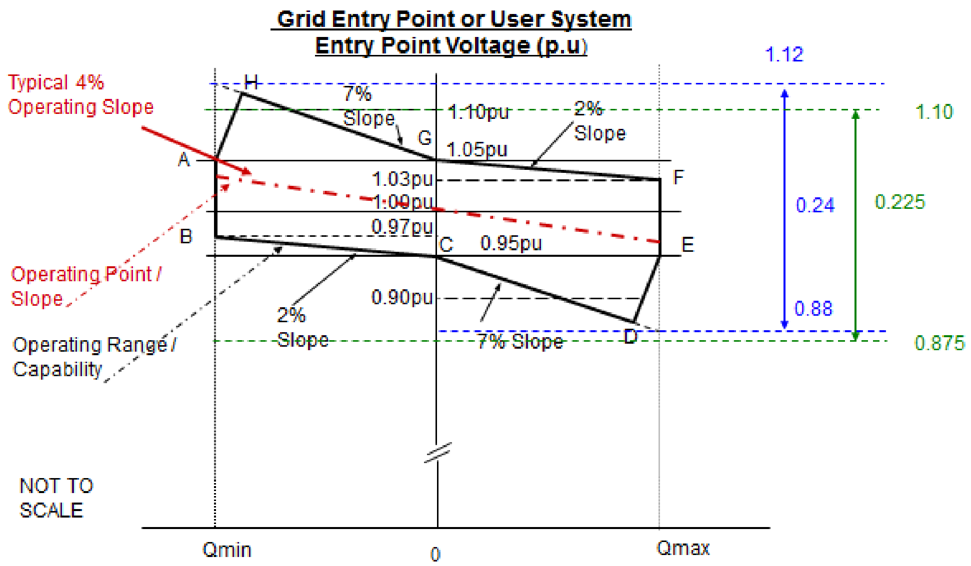



Figure 8.14 – Proposed GB U-Q / Pmax profile settings for a Power Park Module at Maximum Capacity

8.15 Under CC.6.3.4 of the Grid Code, full reactive capability is required to be delivered for a ±5% change in System Voltage. Due to the slope characteristic, this has the tendency to push the voltage limits between 1.12pu and 0.88pu (i.e. a range of 0.24pu as shown by the blue line in Figure 8.14) although it is acknowledged that the GB Grid Code requires the normal operation limits to operate between 1.1pu and 0.9pu. Under RfG, the maximum permitted voltage range for the GB Synchronous Area is set at 0.225 (i.e. the Green line) which would result in a certain amount of capping. Beyond this range, as specified in CC.A.7.2.2.6 and CC.A.7.2.2.7 a Power Park Module would be expected to maintain this output but it is accepted that it is beyond the normal operational range. This issue was discussed during the Workgroup and it was proposed to adopt the same approach as used in the GB Grid Code whilst recognising the normal operating range which is agreed would follow current GB practice.

8.16 A translation of this requirement therefore results in the proposed U-Q/Pmax profile for a Type C or Type D Power Park Module to follow the requirement as shown in Figure 8.16(a) for connections above 33kV and Figure 8.16(b)/ Figure 8.16(c) for connections below 33kV. It should be noted that Figure 8.16(b) is a direct translation of Figure 4 of the GB Grid Code Connection Conditions. This has to be modified in line with Figure 8.16(c) below which is consistent with Figure CC.A.7.2.2c as it is not possible to have a defined operating point on the plateau sections of the diagram shown in Figure 8.16(b).

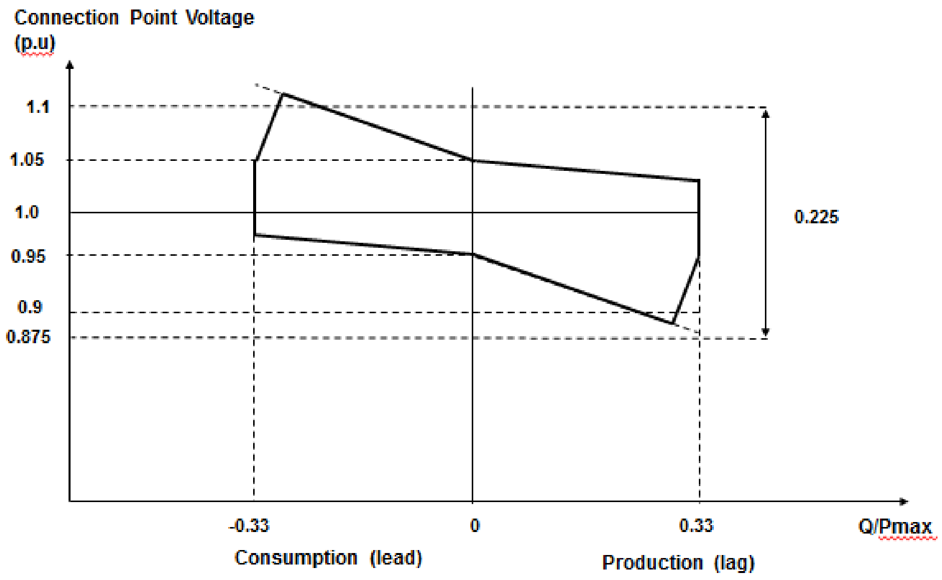



Figure 8.16(a) – U-Q/Pmax profile for a Type C or D Power Park Module with a Connection Point above 33kV.

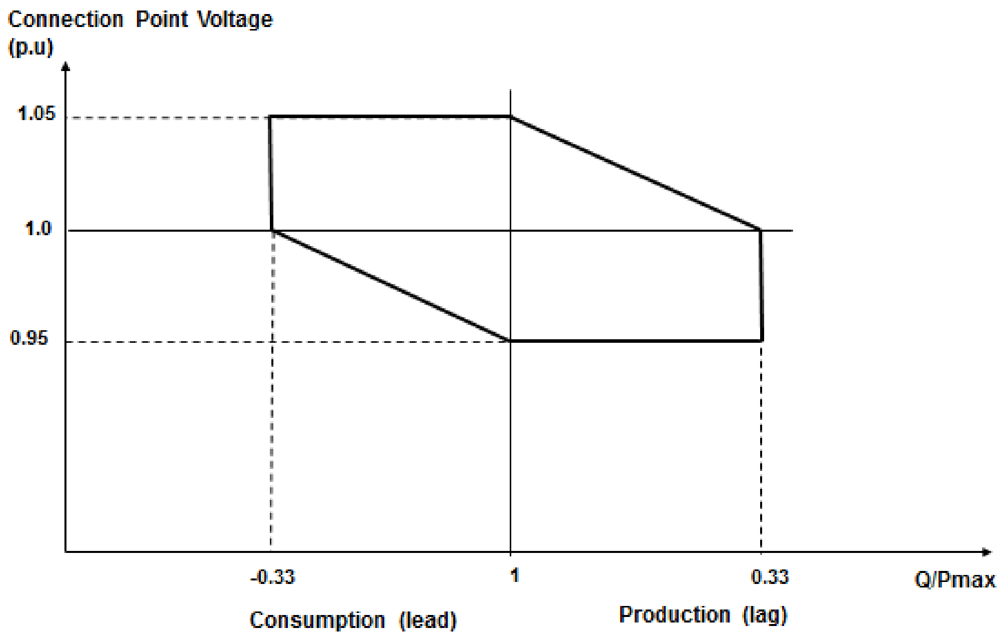



Figure 8.16(b) – Voltage/ Reactive Capability diagram for a Type C or D Power Park Module with a Connection Point connected at or below 33kV.

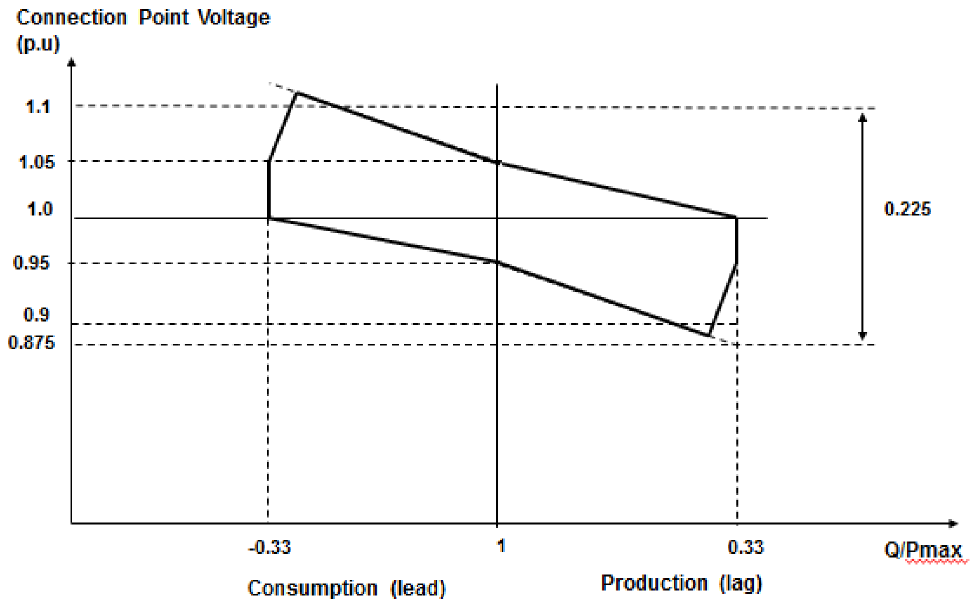



Figure 8.16(c) – U-Q/Pmax profile for a Type C or D Power Park Module with a Connection Point at or below 33kV.

8.17 It is expected that the majority or Type C and D Power Park Modules connected at 33kV or below would be Distribution Connected.

## Type C and Type D Power Park Modules – Reactive Capability below Maximum Capacity

8.18 RfG Article 21(3)(c) defines the requirements for Power Park Modules operating below maximum capacity. In summary the Reactive Power capability for a Type C or Type D Power Park Module operating below maximum capacity is required to satisfy a Power – Reactive Power / Pmax (P – Q/Pmax) requirement. RfG Figure 9 provides the general format for this requirement which is reproduced below in Figure 8.18, although RfG specifies that it is down to the Relevant System Operator in co-ordination with the Relevant TSO to specify these parameters.

8.19 In setting the national parameters, RfG Article 21(3)(c) states that each relevant System Operator in co-ordination with the relevant TSO shall consider the following principles which are interpreted and summarised as follows:

- The national parameters shall not exceed the inner dotted envelope shown in RfG Figure 9
- The national parameters selected by the Relevant System Operator shall not exceed the values specified in RfG Table 9 (for GB this is Max Q/Pmax – 0.66 and Maximum Steady State Voltage Range – 0.225pu)
- The Active Power range of the Q/Pmax profile at zero Reactive Power shall be 1pu. In other words, it is interpreted that with the reactive power set at unity power factor (i.e. zero MVAr) the Power Park Module should be capable of operating over its full MW operating range – i.e. between 0 and 1 pu or zero and Rated MW output.
- The P-Q/Pmax profile can be any shape and include conditions for the reactive power capability at an Active Power Output of zero MW.
- The position of the inner dotted envelope can be at any position so long as it lies within the outer envelope.

- When operating at an active power below maximum capacity (P<Pmax), the Power Park Module shall be capable of providing reactive power at any operating point inside its P-Q/Pmax profile assuming all Power Park Units within the Power Park Module are available. In the case that several Power Park Units within the Power Park Module are out of service, then the current GB practice (CC.6.3.2 (c)) is assumed to apply in which the Reactive Power limits are reduced pro rata to the amount of plant in service.

- The Power Park Module shall be capable of moving to any point within its P-Q/Pmax capability profile in appropriate timescales to target values requested by the relevant System Operator. Under these circumstances the requirements of BC2 would be assumed to apply unchanged.

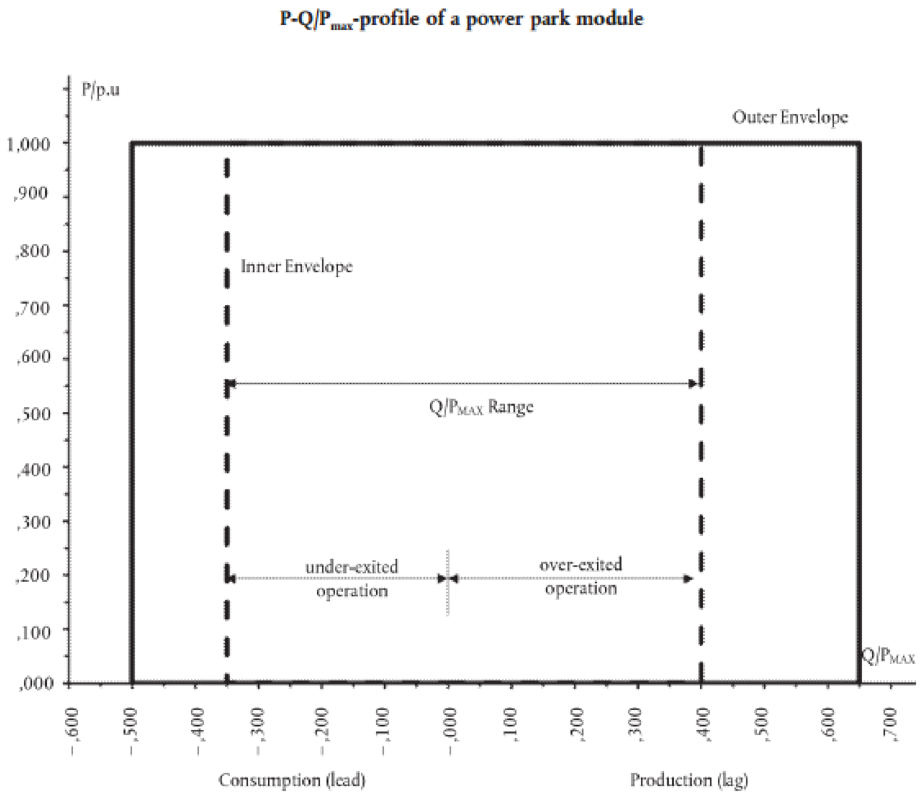
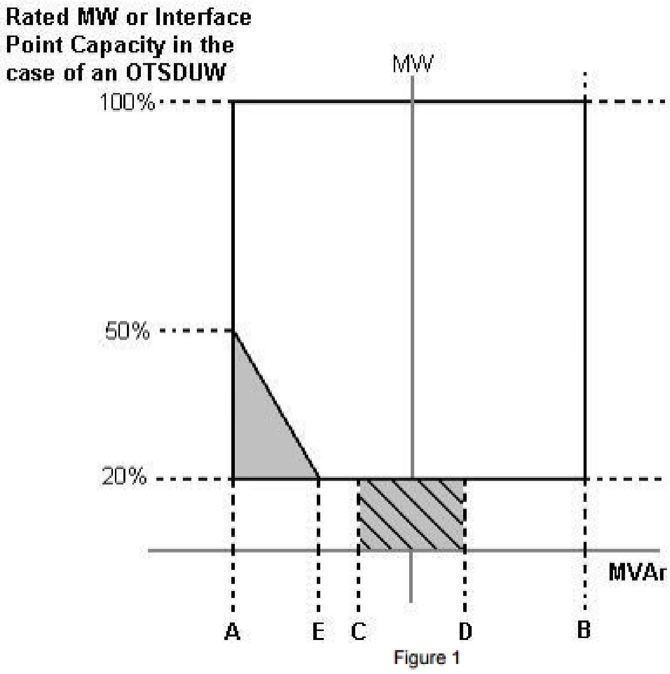



Figure 8.18 – Reproduction of RfG – Figure 9 – P-Q/Pmax profile of a Type C or Type D Power Park Module operating below Maximum Capacity

8.20 The current GB reactive capability requirement is defined in CC.6.3.2 Figure 1 which is reproduced below as Figure 8.20.




| | |
|---|---|
| Point A is equivalent (in MVAr) to | 0.95 leading Power Factor at Rated MW output or Interface Point Capacity in the case of OTSDUW Plant and Apparatus |
| Point B is equivalent (in MVAr) to: | 0.95 lagging Power Factor at Rated MW output or Interface Point Capacity in the case of OTSDUW Plant and Apparatus |
| Point C is equivalent (in MVAr) to: | -5% of Rated MW output or Interface Point Capacity in the case of OTSDUW Plant and Apparatus |
| Point D is equivalent (in MVAr) to: | +5% of Rated MW output or Interface Point Capacity in the case of OTSDUW Plant and Apparatus |
| Point E is equivalent (in MVAr) to: | -12% of Rated MW output or Interface Point Capacity in the case of OTSDUW Plant and Apparatus |

Figure 8.20 – Reproduction of Figure 1 of CC.6.3.2 – Power Park Module – Reactive Capability

8.21 As noted in section 8.10 above, the current reactive capability requirements of CC.6.3.2 can be mapped directly into RfG Article 21(3)(c) other than conversion of Power Factor into Q/Pmax. The proposed GB requirement is therefore shown in Figure 8.21 below.

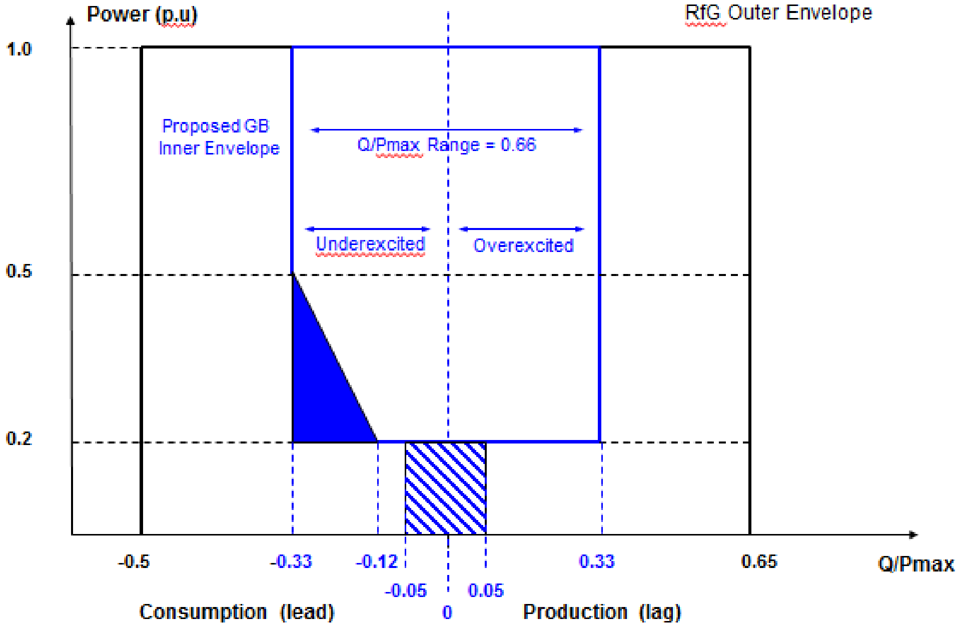



Figure 8.21 – Proposed GB parameters for the P – Q Capability diagram of a Type C and Type D Power Park Module at the Connection Point

8.22 For Type C and Type D Power Generating Modules which are distribution connected, and not subject to a Connection Agreement with National Grid (i.e. they are not CUSC signatories), the Distribution Code is expected to obligate such Generators to meet the requirements of the Grid Code through similar arrangements adopted for LEEMPS. For more details on the LEEMPS connection process the reader is encouraged to consult [3].

## Reactive Power Control Modes for Type C and Type D Power Park Modules

## Voltage Control

8.23 There are three principle ways in which reactive power can be controlled from a Power Generating Module, these being voltage control, reactive power control or power factor control. Under RfG Article 21(3)(d)(vii) the relevant System Operator in co-ordination with the Relevant TSO shall specify which of the above three reactive power control modes applies.

8.24 Under the Grid Code, Power Park Modules comprising Power Park Modules are required to contribute to voltage control (CC.6.3.6, CC.6.3.8 and CC.A.7). For Type C and Type D Power Park Modules it is proposed that this approach is adopted going forward with Reactive Power Control or Power Factor Control being disabled unless otherwise specified in the Connection Agreement (see CC.6.3.8(a)(vi).

8.24 The principles of voltage control for a Power Park Module have been summarised in section 8.13 above which is essentially a setpoint and slope characteristic similar to that which would be expected of a Static Var Compensator (SVC).

8.25 The voltage control requirements for a Type C and Type D Power Park Module are defined in RfG Article 21(3)(d)(i) – (iv) which for completeness are summarised below.

- The Power Park Module shall be capable of contributing to voltage control at the connection point by provision of reactive power exchange with the network with a Setpoint Voltage covering 0.95pu to 1.05pu in steps no greater than 0.01pu, with a slope having a range of at least 2 – 7% in steps no greater than 0.5%. The reactive power output shall be zero (i.e. Unity Power Factor) when the Grid Voltage at the Connection Point is equal to the setpoint value.

- The setpoint may be operated with or without a deadband. The setpoint can be selected in the range of 1pu ± 5% in steps no greater than 0.5%. In other words the setpoint can be any value between 0.95pu and 1.05pu to a resolution of no greater than 0.5% (e.g. 0.99pu, 0.995pu, 1.0pu, 1.005, 1.01).

- Following a step change in voltage, the Power Park Module shall be capable of achieving 90% of the change in reactive power output within a time $t_1$ specified by the relevant System Operator in the range 1 – 5 seconds and must settle at the value specified by the slope within a time $t_2$ to be specified by the relevant System Operator in the range 5 – 60 seconds with a steady state reactive tolerance no greater than 5% of the maximum reactive power. The Relevant System Operator shall specify the time specifications.

8.26 The voltage control performance requirements specified under RfG Article 21(3)(d)(i) – (iv) are believed to be broadly the same as the current GB Grid Code voltage control performance requirements specified under CC.A.7. The parameter ranges are also believed to be consistent other than the settling time $t_2$ which under RfG is set between a range of 5 – 60 seconds and under the current GB Grid Code is set to 2 seconds. This issue has been considered by National Grid and discussed amongst the Workgroup and a value of t2 of 5 seconds is considered to be appropriate without having any undue effects on the performance of the Transmission System. In addition, the current GB Grid Code requirement does not specify the requirement for a deadband within the voltage control system. RfG does not mandate this requirement and therefore it is switched off as part of the GB implementation process.

8.27 Article 21(3)(f) requires a Power Park Module to be capable of contributing to power oscillation damping if specified by the relevant TSO. The voltage and reactive power control characteristics of Power Park Modules should not be adversely affect the damping of power oscillations. Under the current GB Grid Code, power oscillation damping is only required if specified in the Bilateral Agreement if this is required in NGET's view for system reasons. However under CC.A.7.2.4.1 if a Power System Stabiliser is fitted within the voltage control system its settings and performance shall be agreed with National Grid and commissioned in accordance with BC2.11.2 of the Grid Code. This requirement is believed to be consistent with RfG.

8.27 Table 8.27 below provides a comparison between the current GB Grid Code requirements and those under RfG. As can be seen, the majority of the RfG requirements are consistent with current GB requirements.

| European Requirement | GB Requirement |
|---|---|
| Voltage Control settings – (Art 21(3)(d)(ii)) | Steady State Control parameters covered in CC.A.7.2.2 – Parameters are consistent with RfG. |
| Setpoint / Deadband – (Art 21(3)(d)(iii)) | Setpoint / Deadband – (CC.A.7.2.2.2) – No deadband would be set as per current GB Practice. |
| Transient voltage control – $t_1$ (1 – 5 seconds) and $t_2$ (5 – 60 seconds) to be specified – (Art 21(3)(iv)) | Under GB Code $t_1$ is set at 1 second (CC.A.7.2.3.1(ii)) and $t_2$ is set at 2 seconds – (CC.A.7.2.3.1(iv). **The proposal would be to set $t_2$ to 5 seconds.** |
| Power Oscillation Damping – Art 21(3)(f) | As per CC.A.7.2.4 |

Table 8.27 – Comparaison of GB Grid Code and RfG Power Park Module Voltage Control Performance Requirements

## Reactive Power Control

8.28 As described above, Reactive Power Control will not be required from Type C and Type D Power Park Modules unless otherwise specified in the Connection Agreement. That said, where a requirement for Reactive Power Control is specified in the Connection Agreement, it would need to satisfy the requirements of RfG Article 21(3)(d)(v). Whilst it is the intention to switch it off as a GB specific option, where Reactive Power Control is specified through the Connection Agreement, any such requirement would therefore need to be complaint with the requirements of RfG. Additional legal text has therefore been included in the proposed drafting to cater for this issue.

## Power Factor Control

8.29 Similar to Reactive Power Control, Power Factor control will not be required from Type C and Type D Power Park Modules unless otherwise specified in the Connection Agreement. Again where a requirement for Power Factor Control is specified in the Connection Agreement, it would need to satisfy the requirements of RfG Article 21(3)(d)(vi). Whilst it is the intention to switch it off as a GB specific option, where Power Factor Control is specified through the Connection Agreement, any such requirement would therefore need to be complaint with the requirements of RfG. Additional legal text has therefore been included in the proposed drafting to cater for this issue.

# 9 Reactive capability and control performance requirements for Type B Power Park Modules

## General Reactive Capability requirements applicable to Type B Power Generating Modules

9.1 Type B Power Park Modules are subject to lesser requirements than their Type C and Type D counterparts. So far as Type B Power Park Modules are concerned, only reactive capability as specified by the relevant System operator is required.

9.2 RfG Article 20(2)(a) states “with regard to reactive power capability, the relevant System Operator shall have the right to specify the capability of a power park module to provide reactive power”.

9.3 An observation noted as part of the Workgroup is that from a system perspective, there is little benefit in having a reactive capability without a corresponding controlling function (e.g. voltage control, reactive power control or power factor control). This issue is addressed in section 9.10 – 9.12 below.

## Reactive Capability requirements applicable to Type B Power Park Modules

9.4 RfG effectively leaves this choice to the relevant System Operator this being either the Transmission System Operator (i.e. NGET) in respect of Transmission or the Distribution Network Operator in respect of a DNO’s network.

9.5 For a Transmission connected Power Park Module, the current GB Grid Code practice would be for a reactive capability of 0.95 Power Factor Lag to 0.95 Power Factor Lead at Rated MW output at the Connection Point.

9.6 For a DNO connected Power Park Module which falls outside the remit of the Grid Code, the GB reactive capability requirements are specified in the Distribution Code and G59/3. In general, this provides for a fair degree of flexibility. Traditionally when the volume of embedded generation was more limited, common practice tended to promote Power Factor Control. As the volume of Embedded Generation has risen substantially over recent years, the move to a reactive capability and voltage control performance requirement has become more important for two reasons i) the need to manage voltage profile on the DNO networks and ii) it is often cheaper from a connection point of view for the Generator to have a voltage control capability than fixed power factor control. The argument here is that the principles of voltage control and reactive management are the same irrespective of whether the connected Generation is Synchronous or Asynchronous.

9.7 Notwithstanding the points raised in paragraph 9.6 above, there will be cases, for example, Power Park Modules embedded within a private network where the need for power factor control or reactive power control is more appropriate. This would clearly be specified on a case by case basis by the Distribution Network Operator.

9.8 To ensure the requirements therefore remain as flexible as possible, it is proposed that Type B Power Park Modules would be required to have a reactive capability range of 0.95 Power Factor lag to 0.95 Power Factor lead at Rated MW output at the Connection Point unless otherwise agreed with NGET or the relevant Distribution Network Operator. This then enables the Relevant System Operator to have maximum flexibility in defining its requirements at the connection point.

9.9 The value of 0.95 Power Factor Lead to 0.95 Power Factor lag at Rated MW output has been selected on the basis of DNO requirements, general plant capability and equitable treatment with Type C and Type D Power Park Modules.

### Control Performance requirements applicable to Type B Power Park Modules

9.10 As mentioned in section 9.3 above, RfG does not specify any form of reactive power control mode (e.g. voltage control, reactive power control or power factor control) from a Type B Power Park.

9.11 For a Transmission connected Generation, voltage control would be the preferred choice and equally the same argument is true for Distribution connected generation, the reason being that controlling voltage on the network is a fundamental requirement of the Grid Code, SQSS, Distribution Code and ESQCR. In addition the control of voltage on the network can also help reduce the need for reinforcement.

9.12 Notwithstanding the points raised in section 9.11, it is not always appropriate to mandate voltage control in all cases, as there will be situations where power factor control or power factor control are more appropriate. On this basis, it is therefore proposed to maintain maximum flexibility to the relevant System Operator (i.e. SO or DNO) by leaving this choice (including the settings, parameters and capability) to be specified in the Connection Agreement. The proposed drafting would therefore take the following form.

- Type B Power Park Modules shall be capable of contributing to the control of Voltage, Reactive Power or Power Factor at the Connection Point as specified by the Relevant Network Operator. The detailed requirements of this control scheme (including droop settings (if applicable)) shall be specified in the Connection Agreement.

## 10 Configuration, Voltage Range, Reactive Capability and Control performance requirements for AC Connected Offshore Power Park Modules

### Configuration

10.1 RfG Article 23 defines the requirements for AC connected Power Park Modules. These are classified into two categories i) Configuration 1 and ii) Configuration 2. In summary these Configurations are defined as follows:

- Configuration 1:- AC connection to a single onshore Grid interconnection point whereby one or more Offshore Power Park Modules that are interconnected offshore to form an Offshore AC System are connected to the Onshore System.

- Configuration 2:- Meshed AC connections whereby a number of Offshore Power Park Modules are interconnected Offshore to form an Offshore AC System and the Offshore AC System is connected to the Onshore System at two or more Grid Interconnection Points.

10.2 An interpretation of these Configurations is shown in Figure 10.2(a) and Figure 10.2(b) below.

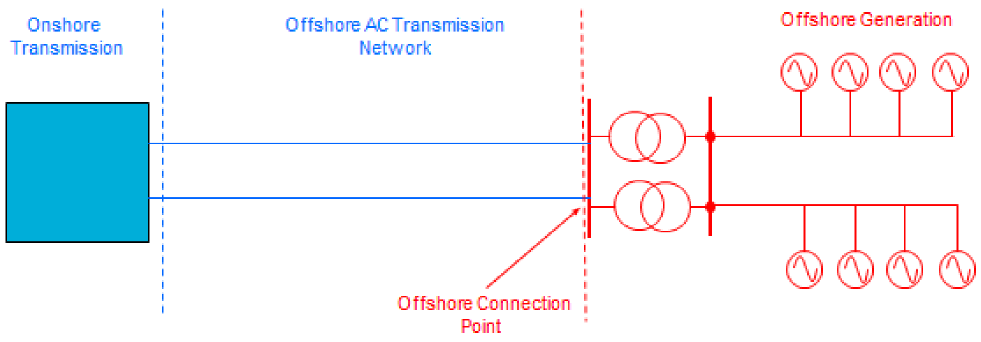



Figure 10.2(a) – Configuration 1 – Radial AC Connected Offshore Power Park Modules

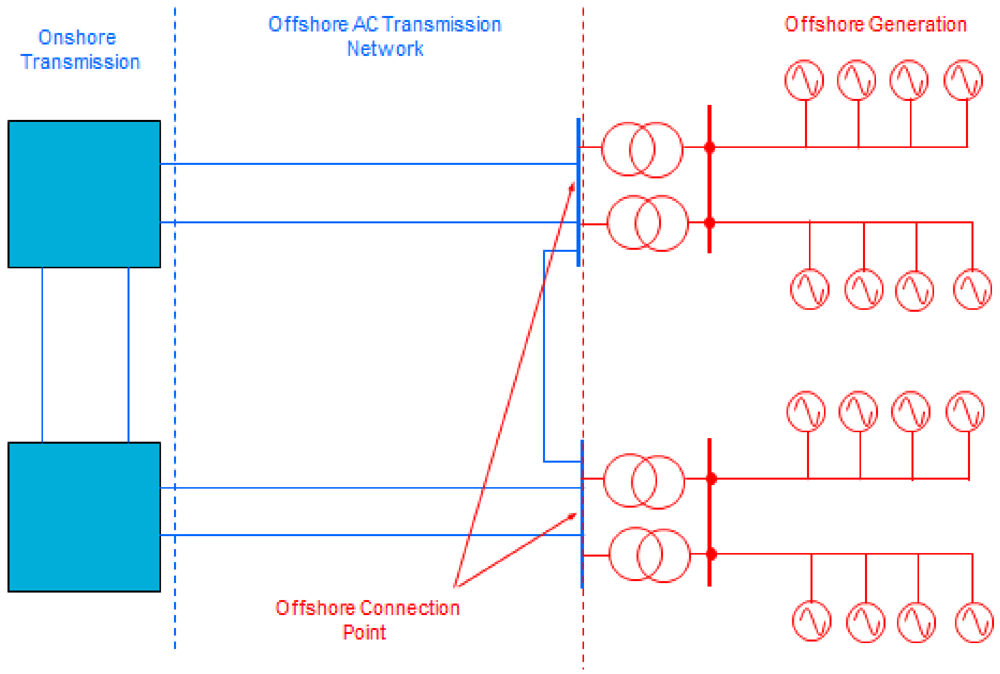



Figure 10.2(b) – Configuration 2 – Meshed AC Connected Offshore Power Park Modules

10.3 For any Power Park Module which is connected to an HVDC System, then the requirements of the HVDC Network Code shall apply.

## Offshore Voltage Range

10.4 RfG Article 25(1) Table 10 (reproduced below) defines the steady state voltage operating range for AC Connected Offshore Power Park Modules. CC.6.1.4 of the Grid Code however defines the steady state operating range of all User's connected to the Transmission System which includes Offshore Generating Units and Offshore Power Park Modules connected to Offshore Transmission Systems.

Table 10

| Synchronous area | Voltage range | Time period for operation |
|---|---|---|
| Continental Europe | 0,85 pu-0,90 pu | 60 minutes |
| | 0,9 pu-1,118 pu (*) | Unlimited |
| | 1,118 pu-1,15 pu (*) | To be specified by each TSO, but not less than 20 minutes and not more than 60 minutes |
| | 0,90 pu-1,05 pu (**) | Unlimited |
| | 1,05 pu-1,10 pu (**) | To be specified by each TSO, but not less than 20 minutes and not more than 60 minutes |
| Nordic | 0,90 pu-1,05 pu | Unlimited |
| | 1,05 pu-1,10 pu (*) | 60 minutes |
| | 1,05 pu-1,10 pu (**) | To be specified by each TSO, but not more than 60 minutes |
| Great Britain | 0,90 pu-1,10 pu (*) | Unlimited |
| | 0,90 pu-1,05 pu (**) | Unlimited |
| | 1,05 pu-1,10 pu (**) | 15 minutes |
| Ireland and Northern Ireland | 0,90 pu-1,10 pu | Unlimited |
| Baltic | 0,85 pu-0,90 pu (*) | 30 minutes |
| | 0,90 pu-1,118 pu (*) | Unlimited |
| | 1,118 pu-1,15 pu (*) | 20 minutes |
| | 0,88 pu-0,90 pu (**) | 20 minutes |
| | 0,90 pu-1,097 pu (**) | Unlimited |
| | 1,097 pu-1,15 pu (**) | 20 minutes |

(*) The voltage base for pu values is below 300 kV.
(**) The voltage base for pu values is from 300 kV to 400 kV.

10.5 In general CC.6.1.4 and RfG Article 25 Tables 10 are the same other than the GB Code requires the voltage range applicable to User's connected below 132kV should be within ±6% and RfG requires AC Connected Offshore Power Generating Modules connected between 132kV and 110kV to remain within the limits of ±10%. It is not envisaged that this will have any significant impact on current GB practice where equipment rated at a nominal voltage of between 132kV and 110kV are generally used.

10.6 All other requirements relating to voltage range are the same as the onshore requirements as detailed in section 4 of this document.

## Reactive Capability requirements applicable to Offshore AC Connected Power Park Modules

10.6 The Reactive Capability requirements for AC connected Offshore Power Park Modules are broadly the same as those for Type C and Type D Onshore Power Park Modules as defined in Article 21(3) other than in respect of the parameters which are redefined in Table 11 of RfG which is reproduced below as Table 10.6.

*Table 11*

**Parameters for Figure 8**

| Synchronous area | Maximum range of $Q/P_{max}$ | Maximum range of steady-state voltage level in PU |
|---|---|---|
| Continental Europe | 0,75 | 0,225 |
| Nordic | 0,95 | 0,150 |
| Great Britain | 0 (*)<br>0,33 (**) | 0,225 |
| Ireland and Northern Ireland | 0,66 | 0,218 |
| Baltic | 0,8 | 0,22 |

(*) At the offshore connection point for configuration 1.
(**) At the offshore connection point for configuration 2.

Table 10.6 – Reproduction of RfG Table 11

10.7 For Configuration 1 Offshore AC Connected Power Park Modules the maximum range of Q/Pmax is set to zero (i.e. unity power factor) and for Configuration 2 Offshore AC Connected Power Park Modules the maximum range of Q/Pmax is set to 0.33. Both Configuration 1 and Configuration 2 have a maximum steady state voltage range of 0.225pu.

10.8 All other requirements such as the need to satisfy the requirements of RfG Figure 8 and Figure 9 remain unchanged.

10.9 Adopting the same approach as outlined in section 8 above other than utilising the revised parameters from Table 11.

10.10 Table 11 of RfG permits the GB Synchronous area to specify a maximum Q/Pmax range of 0.33 for Category 2 Offshore AC Connected Power Park Modules. Based on the equations outlined in section 6 and 8 yields a maximum power factor range of:-

$$Maximum\,GB\;\; Q/Pmax\,range = 0.33$$
$$For\,Symmetrical\,operation = 0.33\;/\;2\;\; = 0.165$$
$$For\,Symmetrical\,operation\,Q\;\;/\;Pmax\,range\;\; = 0.33\;/2\;\; = 0.165$$
$$Giving\,a\,maximum\,Power\,Factor\,range\,of\;\; = Cos\,(arctan\;0.165) = \pm 0.987$$
$$In\,other\,words\,a\,power\;factor\,range\,of\;0.987\;lag\,to\;0.987\;lead\,at\,Rated\,MW\,output$$

10.11 The voltage range remains unchanged at 0.225pu. Redrawing Figures 8.16(a) and 8.21 results in the following requirements for Configuration 2, AC connected Power Park Modules which is shown below as Figure 10.11(a) and 10.11(b).

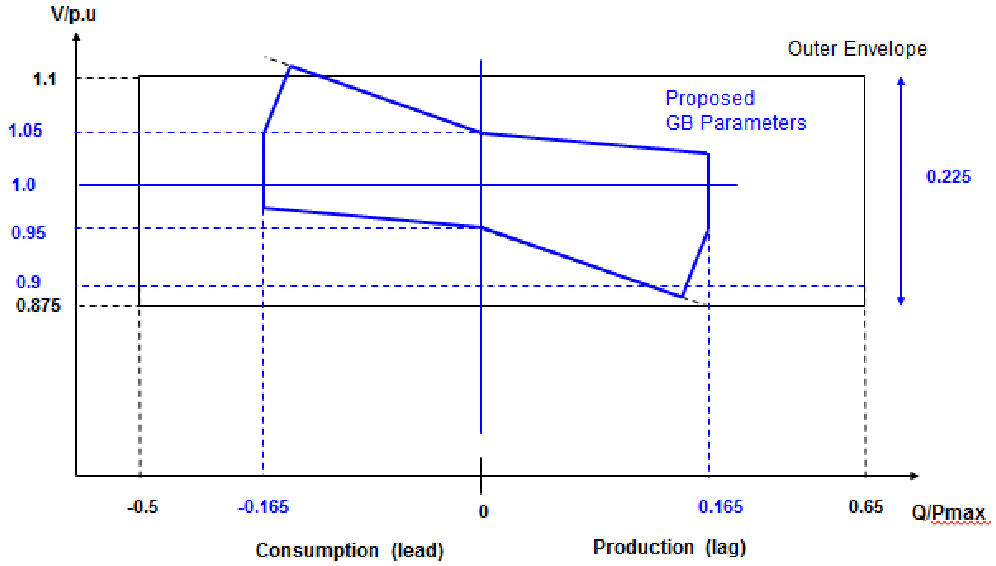



Figure 10.11(a) – Configuration 2 AC connected Offshore Power Park Module U-Q/Pmax – Profile

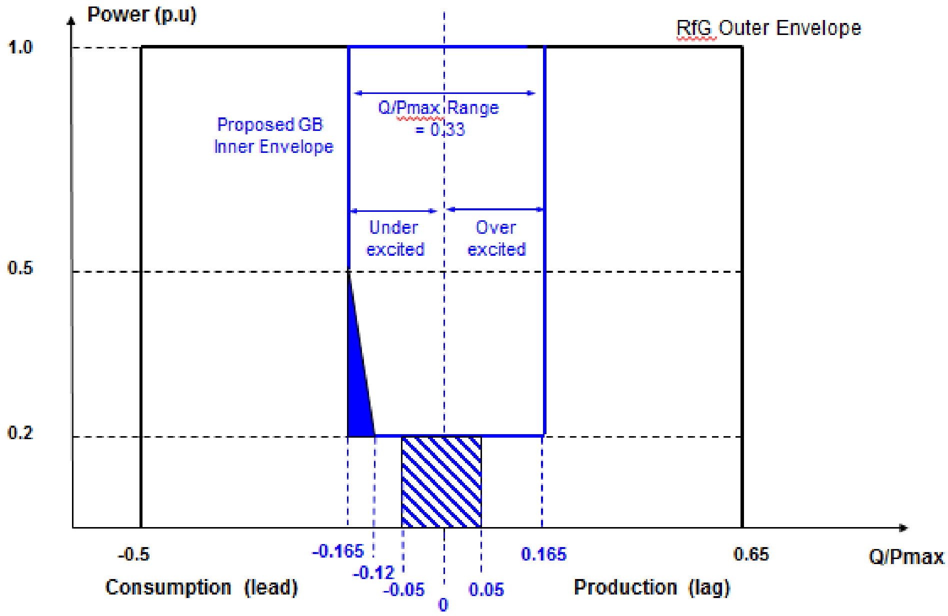



Figure 10.11(b) – Configuration 2 AC connected Offshore Power Park Module P-Q/Pmax – Profile

10.12 For Configuration 1 AC connected Power Park Modules the Reactive Capability at the Offshore connection point is fixed at unity power factor i.e. zero transfer of reactive power. There does not appear to be any tolerance (e.g. ±5%) on the tolerance of reactive power imported or exported to the transmission system. Notwithstanding this, Article 21(3)(d)(v) defines the requirements for Reactive Power control which states where reactive power control is employed, reactive power should be controlled with an accuracy of ±5 MVAr or ±5% of the full reactive power). Interpretation of this requirement would therefore imply that this tolerance should also apply to Configuration 1 AC connected Offshore Power Park Modules.

## Comparison with GB practice and implications of the GB Offshore Transmission Regime

10.13 GB is unique in so far that it is the only country in Europe with an Offshore Transmission regime – i.e. the concept of separating Offshore Transmission from Offshore Generation, with the concept of the Offshore Transmission Assets being subject to tender and separate ownership from the Onshore Transmission Owner, whilst control and operation remains under the remit of the GB System Operator (NGET).

10.14 It is beyond the scope of this consultation to describe the details of the Offshore Transmission Regime, however if the reader is interested in the details of these arrangements reference is made to [4].

10.15 At this point it is worth noting that the Offshore Transmission regime in GB applies only to connections which have connections to shore of 132kV or above. For Offshore Generators with connections to shore below 132kV, the Offshore cable connections are treated as Generator assets and the applicable connection requirements therefore apply at the Onshore Connection Point. RfG Article 23(1) states "An AC connected Power Park Module located offshore which does not have an offshore connection point shall be considered as an onshore Power Park Module and thus shall comply with the requirements governing Power Park Modules connected Onshore".

10.16 For future Offshore Generators which are part of the Offshore Transmission regime (i.e. connected via offshore cables of 132kV or above) the GB Grid Code would need to be updated to ensure it is consistent with the Offshore RfG. The requirements on the Offshore Transmission System including the requirements at the Transmission Interface Point (i.e. where the Offshore Transmission System connects to the Onshore Transmission System) as specified in the Grid Code in respect of OTSDUW Plant and Apparatus or STC for Offshore Transmission Systems would remain unchanged).

10.17 In GB, the reactive power capability requirements for Offshore Power Park Modules are defined under CC.6.3.2(e) for which three possible options are available, these being i) zero transfer of reactive power at the LV side of the Offshore platform, ii) the equivalent of zero transfer of reactive power at the LV side of the Offshore Platform but with respect to the Offshore Connection Point (e.g. if the Connection Point is at the HV side of the Offshore Platform the reactive injection should be equivalent to zero transfer of reactive power at the LV side of the Offshore Platform or iii) An alternative Reactive Power Capability as agreed between the Generator, Offshore Transmission Licensee and NGET. Under RfG, the options available are more limited. AC connected Configuration 1 Offshore Power Park Modules are required to supply zero transfer of reactive power at the Connection Point. This requirement could be interpreted to restrict the use of option (iii) above, where the capability of the turbines could for example be used to control the voltage at the Offshore Platform and hence prevent the need for the Offshore Transmission Licensee to install reactive compensation equipment on the Offshore Platform. Whilst RfG specifies a minimum capability of unity power factor at the Offshore Connection Point, it should not preclude the use of a commercial agreement between the System Operator, Offshore Transmission Licensee and Offshore Generator which would aim to drive the most economic and efficient solution for all parties involved.

10.18 For Configuration 2 AC connected Power Park Modules, which are connected via a meshed network, the requirements are more akin to the onshore requirements albeit with a reduced reactive range. At the time of writing there are no meshed AC connected Offshore Networks and few planned for the future. It is not envisaged that these requirements will have major implications, especially in view of the reactive capability requirements at the Interface Point which are expected to remain unchanged going forwards. Notwithstanding this, it is also noted that if a wider reactive capability range is required, than the minimum specified under RfG (i.e. 0.165 Power Factor Lead to 0.165 Power Factor Lag at rated MW output) then there should be no reason why commercial arrangements could not be put in place if this is the most economic and efficient solution for all parties involved.

10.19 As part of the discussions with a Workgroup member, it was noted that the requirements of Article 25(5) (which relate to the offshore reactive capability requirements) states that the requirements of Article 21(3)(b) also apply to Offshore AC connected Power Park Modules except the parameters in RfG Table 9 are replaced by the parameters in Table 11. It has been noted that the requirements in Article 21(3)(a) also apply to AC Connected Offshore Power Park Modules though it is understood that this requirement relates to the need to install reactive compensation equipment at the Connection Point where the reactive capability requirements at the Connection Point cannot be provided by the Generating Plant.

10.20 As the GB Code (of which the Offshore elements are an intrinsic part) needs to be made consistent with RfG, the legal drafting in Annex 2 also covers any consequential Offshore updates that may be required. As such the drafting also includes proposed changes to OTSDUW (Offshore Transmission System Development User Works) Plant and Apparatus. As a consequence of this work, any changes which are necessary would also need to be included in the STC, subject to appropriate Governance Arrangements.

# 11 Cost Benefit Analysis

11.1 In complying with the RfG there will be a need to update the GB Codes to ensure they are consistent with the European requirements. The purpose of this section is to outline the material costs that Generators and Network Owners / Operators could be exposed to as a result of this implementation.

11.2 In general, the implementation of the RfG voltage / reactive capability requirements into the GB Code is largely a translation exercise as many of the requirements in GB are already consistent with those in RfG. The parties most significantly affected by these changes will be developers who are currently familiar with the G83 or G59/3 requirements who have had little previous exposure to the Grid Code as RfG defines requirements down to 800W rather than the current 50MW (E&W), 30MW (SPT) or 10MW (SHE Transmission) thresholds defined in the Grid Code. By in large these requirements are not believed to introduce significant costs to Generators as a result of RfG implementation due to the flexibility available to Network Owners and Operators.

11.3 The sector which could be impacted by the voltage / reactive RfG provisions are those connected to Offshore Transmission Networks. These issues are articulated in section 10 above but it is noted that these risks should be mitigated by the use of commercial arrangements in an attempt to drive the most economic and efficient solution. Clearly if commercial arrangements were not negotiated the Offshore developer could be exposed to the costs of installing additional reactive compensation on the Offshore Platform.

11.4 To summarise, Table 11.4 below has been constructed to provide an indication of the material costs to Generators and Network Operators as a result of implementing the RfG Reactive Power Capability and associated Reactive Control Modes of Operation.

| Generator Type | Cost to Generator | Cost to SO / TO | Cost to DNO | Comments |
|---|---|---|---|---|
| Type A Power Generating Modules | Not applicable | Not applicable | Not applicable | RfG does not specify reactive capability or control performance requirements for Type A Power Generating Modules. |
| Type B SPGM | Small | Negligible | Negligible | Sufficient flexibility in Network Code and drafting to permit the Network Operator to define what requirement applies at the connection point. There will be a cost to implement the Generator Control Scheme via droop control but this is not believed to be significant from current practice |
| Type B PPM | Negligible | Negligible | Negligible | Code has sufficient flexibility for Network Operator to define requirement at Connection Point as per current requirements |
| Type C SPGM | Negligible | Negligible | Negligible | As per current GB requirement other than the way in which the requirements are specified |
| Type C PPM | Negligible | Negligible | Negligible | As per current GB requirement other than the way in which the requirements are specified |
| Type D SPGM | Negligible | Negligible | Negligible | As per current GB requirement other than the way in which the requirements are specified |
| Type D PPPM | Negligible | Negligible | Negligible | As per current GB requirement other than the way in which the requirements are specified |
| Configuration 1 AC Connected Offshore PPM | Variable | Negligible | Not applicable | RfG requirements do not provide for wider reactive capability to be used at the Offshore Grid Entry Point as per current GB drafting. Potentially there could be additional costs as a result of this however it is believed that these costs could be mitigated by an appropriate commercial agreement backed up by a robust cost benefit |

| | | | | |
|---|---|---|---|---|
| | | | | analysis. |
| Configuration 2 AC Connected Offshore PPM | Small | Negligible | Not applicable | There are no projects currently planned in GB for this type of connection. Potentially there could be additional costs as a result of the restricted MVAr range however it is believed that these costs could be mitigated by an appropriate commercial agreement backed up by a robust cost benefit analysis. |

Table 11.4 – Expected costs as a result of implementing the RfG Reactive Capability / Reactive Power Control modes

## 12 Lessons learnt from implementation of the Gas European Codes

12.1 Similarly to electricity, the European Third Energy Package as applied to the creation of a more harmonised European internal energy market for gas resulted in the development of a number of European Network Codes. The national implementation of these codes was taken forwards through an Industry Workgroup and resulted in a number of modifications to the GB Gas Uniform Network Code (UNC) in order to achieve legal compliance with the Codes. These took place between October 2013 and May 2016.

12.2 The Gas ENCs are as follows:

- Congestion Management Procedures (CMP)
- Capacity Allocation Mechanisms (CAM)
- Network Code on Gas Balancing of Transmission Networks (Balancing Code)
- Network Code on Interoperability and Data Exchange Rules
- More info here: http://www.gasgovernance.co.uk/euronetcodes

12.3 We have looked at how the gas implementation took place to see what lessons could be learned from this or what precedents could have been set.

12.4 Two key points have been highlighted:

- The development of GB code modifications was carried out in manageable chunks that were consulted on and taken forwards individually. While this increased the need for coordination and careful planning, these issues were outweighed by the need to keep the work manageable and avoid consulting on too much material at once.

- All of the UNC European Code provisions were put into a new section of the UNC, the European Interconnection Document (EID). This is a new document forming part of the Uniform Network Code (UNC) and sits alongside the other parts of the UNC, i.e. Transportation Principal Document (TPD), Offtake Arrangements Document, Independent Gas Transporter Document, (subject to approval of the Project Nexus modifications), Transition Document, Modification Rules and General Terms. This was done for reasons of clarity and also because some shippers only participating in domestic markets were not going to be subject to ENC provisions.

12.5 A legal roadmap on the development of the Gas European Code implementation giving more background was produced: http://www.gasgovernance.co.uk/sites/default/files/EU%20Codes%20Legal%20Roadmap.pdf

12.6 In conclusion, numerically there are four Gas ENCs compared to eight Electricity ENCs (counting TSOG as one rather than three); there is also only one GB gas code, the UNC, compared to five GB electricity codes (the CUSC, DCUSA, BSC, Grid Code and Distribution Code). The neatness of the single EID solution is therefore not as achievable for electricity but has been considered. The proposed solution for the connection codes (RfG, DCC, HVDC) in establishing a new European Connection Conditions (ECC) section of the Grid Code, and similar changes to the Distribution Code and its specific Engineering Recommendations, is however roughly analogous to this.

12.7 This consultation will invite responses from stakeholders on the structure of the solution being proposed and the options given. Please note however that in terms of what is achieved in the GB codes, since this facilitates implementation of European Law, the choice of format is presentational only; in terms of the technical content this will be the same for each.

# 13 Code Structure

13.1 For the purpose of the Grid Code it has been considered that the Connection Conditions (CC's) and other affected Grid Code sections should be duplicated in their entirety and updated to ensure consistency with the EU Code.

13.2 From a User's perspective it simply means that a new User can comply with the requirements of RfG by meeting the new EU sections of the GB Grid Code and existing Users meet the requirements of the code as currently drafted, which prevents the User from having to read multiple documents.

13.3 For distribution connected generators, the new requirements for Reactive Capability and Control have been drafted into a new document, ER G99, which will be introduced to replace ER G59. This will bear on Type A and B Power Generating Modules. G98-2 as drafted currently applies up to 50kW and G99 applies at or above 50kW.

13.4 Linkage between the Distribution Code and Grid Code will require some co-ordination, but at a high level it is envisaged that the requirements for Type A and B Embedded Generators would reside in the Distribution Code and all other requirements (Type C – D Embedded Generators and all Transmission Connected Generators (Type A - D) would reside in the Grid Code). The full details of this linkage will be developed over the coming months and introduced as part of the final implementation of the RfG

13.5 Type D Power Generating Modules greater than 100MW would be caught by the provisions of CUSC and Grid Code and provisions on C and D Power Generating Modules less than 100MW would be addressed by an approach similar to that for Licence Exempt Embedded Medium Power Stations (LEEMPS).

13.6 For distribution connected generators it is currently proposed to replace the current ER G83 and ER G59 with two new documents of similar scope, ER G98 and ER G99. Both G98 and G99 will only apply to new connections.

13.7 This consultation includes draft legal text for the application of reactive power capability and its associated control modes applicable to Type B, Type C and Type D Power Generating Modules – see Annex 2, 3 and 4.

13.8 It might be more appropriate, when the implications of all the EU Network Codes are better understood that the requirements on distribution connected generators are better incorporated into the body of the Distribution Code, rather than in the stand-alone documents G98 and G99. Stakeholder's views on this would be welcome at any time, and particularly in response to this consultation. A full version of the current draft of G99 can be provided on request.

13.9 The Table below summarises how these requirements would apply.

| Type | Network Connection | Applicable Industry Codes |
|---|---|---|
| A | Distribution | Distribution Code + G98/G99 (which replace G83/G59) |
| | Transmission | Grid Code , CUSC, BSC |
| B | Distribution | Distribution Code + G98/G99 (which replace G83/G59) |
| | Transmission | Grid Code , CUSC, BSC |
| C | Distribution | Distribution Code refers to Grid Code (sub 100MW via LEEMPS type arrangements) unless Type C Generator opts to be a BM party. If it opts for BM status it will need to meet the requirements of the Grid Code, CUSC and BSC in its own right. |
| | Transmission | Grid Code , CUSC, BSC |
| D | Distribution | Distribution Code plus Distribution Code refers to Grid Code (sub 100MW via LEEMPS type arrangements) unless Type D Generator opts to be a BM party and is less than 100MW. If it opts for BM status or greater than 100MW it will need to meet the requirements of the Grid Code, CUSC and BSC in its own right as well as the requirements of the Distribution Code. |
| | Transmission | Grid Code , CUSC, BSC |

# 14 Impact & Assessment

## Impact on the Grid Code

14.1 These modifications are necessary to ensure the Grid Code and Distribution Code are consistent with the Voltage and Reactive Power Capability elements of the EU Network Code Requirements for Generators (RfG) document which entered into Force on 17th May 2016 and requires Member State Codes to be consistent with these requirements by 17th May 2018 at the latest.

14.2 These requirements apply only to new Power Generating Modules, the existing requirements as detailed in the current Connection Conditions will remain unchanged. To address this issue, it is therefore proposed to introduce a new section to the Grid Code (a duplicate of the Connection Conditions ECC's) which will apply to new User's (i.e. Users who are seeking a connection after 17th May 2018 or have not placed their contract for major plant items by 17th May 2018.

14.3 Under the Preface of the Grid Code section P.2 states "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.

14.4 The current requirements stipulated under the Connection Conditions of the GB Grid Code are not consistent with RfG and therefore amendments to the GB Code will be a necessity to avoid contravention of European law.

14.5 The proposals have been discussed amongst the GC0048 Workgroup and their comments have been taken into consideration which results in the proposals highlighted in this consultation.

14.6 In developing these proposals National Grid has attempted to develop a set of requirements which are consistent with the RfG requirements, strike the right balance between the needs of the Transmission System and Generator technology, without exposing them to excessive cost. These issues are summarised in section 11 of this report.

14.7 National Grid believe the proposed requirements deliver a set of GB parameters for implementation of the RfG Code into the GB Grid Code. It is however acknowledged that, the Generation background continues to change with a trend towards smaller units connecting at distribution levels. It is therefore possible that a further review may be required in the future but such change is considered unlikely at this stage and in addition would need to be progressed through the GB governance of the Grid Code Review Panel.

## Impact on the Distribution Code

14.8 The RfG introduces new voltage / reactive power requirements for all generators that are Type B or larger.

**Timeline**

**Workgroup Meeting Dates**

M1 - 01 January 2012
M2 - 01 January 2012
M3 - 01 January 2012
M4 - 01 January 2012
M5 - 01 January 2012

14.9 The parameters for Reactive Power Capability and voltage control / reactive power performance for distribution connected generators have been developed jointly with those applicable to transmission connected generators in GC0048.

14.10 The new requirements have been drafted into a new document, ER G99 that will replace ER G59. ER G99, like ER G59 it will be cited in Annex 1 of the Distribution Code and there be governed, and binding on generators, as though it were itself part of the Distribution Code.

### Impact on National Electricity Transmission System (NETS)

14.11 The proposed changes will provide greater clarity and certainly to Generators who are required to comply with the RfG requirements. The proposed requirements also remove the regional differences criteria which are embodied within the current GB Grid Code.

### Impact on Grid and Distribution Code Users

14.12 Users will have to comply with the revised Grid and Distribution Code requirements, but this will ensure compliance with EU and UK law.

### Impact on Greenhouse Gas emissions

14.13 The proposed modification will have limited impact on greenhouse emissions, however for offshore developers there is a risk that they may have to procure additional reactive compensation equipment at the offshore platform rather than rely on the capability of the Offshore Generators. This in itself will result in additional greenhouse gas emissions as a result of the need to procure more equipment.

### Assessment against Grid Code Objectives

*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);*

The proposals will ensure the voltage / reactive power capability elements of RfG are consistent across GB and remove the need for regional differences.

*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 electricity transmission system operator area taken as a whole; and*

The proposal (as defined by RfG) applies to Power Generating Modules of 1MW and above. The current GB Grid Code requirements only apply to Generating Units and Power Park Modules which form part of a Large or Medium Power Station. As this requirement now applies to a greater volume of Generating Plant there will be greater consistency between the requirements in the Grid Code and Distribution Code which will result in enhanced security of the Transmission System. It will also remove the issue of Regional Differences between England and Wales and Scotland.

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.*

This requirement is driven by EU Commission Regulation **2016/631** and is therefore a mandatory change to ensure GB compliance with European law.

### 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; Condition 21 of the Distribution Licence requires the licensee to comply with any relevant legally binding decisions of the European Commission and/or the Agency. As such these proposals are necessary to ensure consistency with the European Commission Directive on Cross Border Trade.*

ii. *to facilitate competition in the generation and supply of electricity*

The proposals will ensure the Voltage / Reactive Power requirements are consistent across GB and remove the need for regional differences. They will also result in greater consistency between User's connecting to the Transmission System and Distribution System.

*iii.* 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.

This requirement is driven by European Directive XXXX and therefore a mandatory and necessary change.

### Impact on core industry documents

14.14 The proposed modification will have an impact on the Grid Code and the Distribution Code.

### Impact on other industry documents

14.15 The proposed modification will affect Engineering Recommendation documents G59 and G83, and replace them with G99 and G98.

### Implementation

[RJW to provide]

## 15 References

[1] Grid Code Consultation GC0028 – Constant Terminal Voltage – Available at:- http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=41902

[2] Grid Code Consultation H/04 – Changes to incorporate new Generation Technologies and DC Interconnectors (Generic Provisions) http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=13419

[3] – LEEMPS – Grid Code Consultation D/05 - Grid Code changes associated with Licence Exempt Embedded Medium Power Stations – Available at:- http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/Modifications/Concluded/2005/

[4] Offshore Generation and Transmission in Great Britain a Review of the connection process and Technical Performance Requirements – A Johnson – Presented at the 12th Wind Integration Workshop London 2013 – International Workshop on Large-Scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Power Plants

## 16 Consultation Responses

Views are invited upon the proposals outlined in this consultation, which should be received by [Insert Date].

Your formal responses may be emailed to:
grid.code@nationalgrid.com or [ENA - TBC]

Responses are invited to the following questions:

1. Do you agree that the proposals outlined in the consultation reflect the correct interpretation of the Voltage Range, Reactive Power Capability and associated control performance requirements? If not, please state why.
2. Do you agree that the proposed requirements for Type B, Type C and Type D Power Generating Modules reflect the RfG requirements and strike the right balance between the needs of the System and the costs to which Generators are exposed?
3. Do you agree that the same reactive power capability requirements should apply across the whole of GB and there should be no regional differences? If you do not agree, please state why?

4. Do you agree that the control capability (i.e. voltage control, reactive power control or power factor control) for Type B Power Park Modules should be set by the Relevant System Operator in the Connection Agreement dependent upon the local connection topology and arrangements? If not please state why?
5. Do you agree that the same Excitation and Voltage Control Performance requirements as applicable to Type D Synchronous Power Generating Modules should also apply to Type C Synchronous Power Generating Modules? If not, please state why you feel such requirements would not be applicable bearing in mind similar technology is employed.
6. Do you agree that from an RfG perspective the same requirements for Type B, Type C and Type D Power Generating Modules are the same irrespective of whether they are connected to the Transmission System or Distribution System? If not please state why?
7. Do you agree that the Offshore Transmission Arrangements (OTSDUW) should be included as part of the drafting.
8. Do you agree that RfG limits the Reactive Power capability required at the Offshore Connection Point for Configuration 1 and Configuration 2 AC Connected Offshore Power Park Modules? Do you agree however that any alternative reactive capability range (as currently defined in the GB Grid Code) could be made up through a commercial arrangement or Bilateral Connection Agreement (if possible) between the Offshore Transmission Licensee, NGET and Offshore Generator. If so, would you support this as an approach. If not please state why you feel such arrangements would not be appropriate.
9. 

**Legal Drafting:**

10. Do you support the proposed legal drafting approach for Grid Code?
11. Do you have any views about the structure of the distribution documents, i.e. the scope of G98 and G99?

12. Do you think it is appropriate to maintain G98 and G99 as stand-alone documents, or do you think that as other EU Network Codes are implemented it might be more appropriate to include all the relevant requirements for both connection and ongoing operation in a single document? Or do you believe that such a decision should be made once further investigation of the effects of other EU Codes on the GB distribution documents has been undertaken?

**Other:**

13. Do you have any other comments you wish to make in relation to this consultation?

If you wish to submit a confidential response please note the following:

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 marked "Private & Confidential" will be disclosed to the Authority in full but, unless agreed otherwise, will not be shared with the Grid or Distribution Code Review Panels 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 & Confidential".

## Annex 1 – Relevant Voltage / Reactive Power Capability extracts from the European Network Code Requirements for Generators

### Article 16(2)

2. Type D power-generating modules shall fulfil the following requirements relating to voltage stability:

(a) with regard to voltage ranges:

(i) without prejudice to point (a) of Article 14(3) and point (a) of paragraph 3 below, a power-generating module shall be capable of staying connected to the network and operating within the ranges of the network voltage at the connection point, expressed by the voltage at the connection point related to the reference 1 pu voltage, and for the time periods specified in Tables 6.1 and 6.2;

(ii) the relevant TSO may specify shorter periods of time during which power-generating modules shall be capable of remaining connected to the network in the event of simultaneous overvoltage and underfrequency or simultaneous undervoltage and overfrequency;

(iii) notwithstanding the provisions of point (i), the relevant TSO in Spain may require power-generating modules to be capable of remaining connected to the network in the voltage range between 1,05 pu and 1,0875 pu for an unlimited period;

(iv) for the 400 kV grid voltage level (or alternatively commonly referred to as 380 kV level), the reference 1 pu value is 400 kV; for other grid voltage levels, the reference 1 pu voltage may differ for each system operator in the same synchronous area;

(iv) notwithstanding the provisions of point (i), the relevant TSOs in the Baltic synchronous area may require power-generating modules to remain connected to the 400 kV network in the voltage range limits and for the time periods that apply in the Continental Europe synchronous area;

*Table 6.1*

| Synchronous area | Voltage range | Time period for operation |
|---|---|---|
| Continental Europe | 0,85 pu-0,90 pu | 60 minutes |
| | 0,90 pu-1,118 pu | Unlimited |
| | 1,118 pu-1,15 pu | To be specified by each TSO, but not less than 20 minutes and not more than 60 minutes |
| Nordic | 0,90 pu-1,05 pu | Unlimited |
| | 1,05 pu-1,10 pu | 60 minutes |
| Great Britain | 0,90 pu-1,10 pu | Unlimited |
| Ireland and Northern Ireland | 0,90 pu-1,118 pu | Unlimited |
| Baltic | 0,85 pu-0,90 pu | 30 minutes |
| | 0,90 pu-1,118 pu | Unlimited |
| | 1,118 pu-1,15 pu | 20 minutes |

The table shows the minimum time periods during which a power-generating module must be capable of operating for voltages deviating from the reference 1 pu value at the connection point without disconnecting from the network, where the voltage base for pu values is from 110 kV to 300 kV

*Table 6.2*

| Synchronous area | Voltage range | Time period for operation |
|---|---|---|
| Continental Europe | 0,85 pu-0,90 pu | 60 minutes |
| | 0,90 pu-1,05 pu | Unlimited |
| | 1,05 pu-1,10 pu | To be specified by each TSO, but not less than 20 minutes and not more than 60 minutes |
| Nordic | 0,90 pu-1,05 pu | Unlimited |
| | 1,05 pu-1,10 pu | To be specified by each TSO, but not more than 60 minutes |
| Great Britain | 0,90 pu-1,05 pu | Unlimited |
| | 1,05 pu-1,10 pu | 15 minutes |
| Ireland and Northern Ireland | 0,90 pu-1,05 pu | Unlimited |
| Baltic | 0,88 pu-0,90 pu | 20 minutes |
| | 0,90 pu-1,097 pu | Unlimited |
| | 1,097 pu-1,15 pu | 20 minutes |

The table shows the minimum time periods during which a power-generating module must be capable of operating for voltages deviating from the reference 1 pu value at the connection point without disconnecting from the network where the voltage base for pu values is from 300 kV to 400 kV.

(b) wider voltage ranges or longer minimum time periods for operation may be agreed between the relevant system operator and the power-generating facility owner in coordination with the relevant TSO. If wider voltage ranges or longer minimum times for operation are economically and technically feasible, the power-generating facility owner shall not unreasonably withhold an agreement;

(c) without prejudice to point (a), the relevant system operator in coordination with the relevant TSO shall have the right to specify voltages at the connection point at which a power-generating module is capable of automatic disconnection. The terms and settings for automatic disconnection shall be agreed between the relevant system operator and the power-generating facility owner.

## *CHAPTER 2*
## **Requirements for synchronous power-generating modules**
### *Article 17*
### **Requirements for type B synchronous power-generating modules**

1. Type B synchronous power-generating modules shall fulfil the requirements listed in Articles 13, except for Article 13(2)(b), and 14.

2. Type B synchronous power-generating modules shall fulfil the following additional requirements relating to voltage stability:

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

(b) with regard to the voltage control system, a synchronous power-generating module shall be equipped with a permanent automatic excitation control system that can provide constant alternator terminal voltage at a selectable setpoint without instability over the entire operating range of the synchronous power-generating module.

Article 18

**Requirements for type C synchronous power-generating modules**

1. Type C synchronous power-generating modules shall fulfil the requirements laid down in Articles 13, 14, 15 and 17, except for Article 13(2)(b) and 13(6), Article 14(2) and Article 17(2)(a).

2. Type C synchronous power-generating modules shall fulfil the following additional requirements in relation to voltage stability:

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

(b) with regard to reactive power capability at maximum capacity:

(i) the relevant system operator in coordination with the relevant TSO shall specify the reactive power provision capability requirements in the context of varying voltage. For that purpose the relevant system operator shall specify a U-Q/Pmax-profile within the boundaries of which the synchronous power-generating module shall be capable of providing reactive power at its maximum capacity. The specified U-Q/Pmax profile may take any shape, having regard to the potential costs of delivering the capability to provide reactive power production at high voltages and reactive power consumption at low voltages;

(ii) the U-Q/Pmax-profile shall be specified by the relevant system operator in coordination with the relevant TSO, in conformity with the following principles:

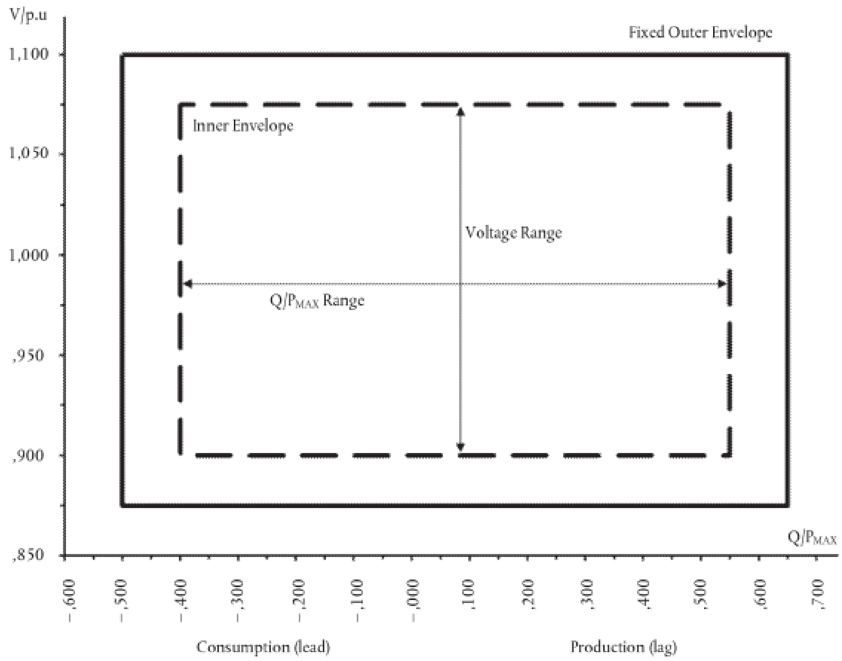
— the U-Q/Pmax-profile shall not exceed the U-Q/Pmax-profile envelope, represented by the inner envelope in Figure 7,

— the dimensions of the U-Q/Pmax-profile envelope (Q/Pmax range and voltage range) shall be within the range specified for each synchronous area in Table 8, and

— the position of the U-Q/Pmax-profile envelope shall be within the limits of the fixed outer envelope in Figure 7;

Figure 7

**U-Q/Pmax-profile of a synchronous power-generating module**




The diagram represents boundaries of a U-Q/Pmax-profile by the voltage at the connection point, expressed by the ratio of its actual value and the reference 1 pu value, against the ratio of the reactive power (Q) and the maximum capacity (Pmax). The position, size and shape of the inner envelope are indicative.

| Synchronous area | Maximum range of $Q/P_{max}$ | Maximum range of steady-state voltage level in PU |
|---|---|---|
| Continental Europe | 0,95 | 0,225 |
| Nordic | 0,95 | 0,150 |

| Synchronous area | Maximum range of $Q/P_{max}$ | Maximum range of steady-state voltage level in PU |
|---|---|---|
| Great Britain | 0,95 | 0,225 |
| Ireland and Northern Ireland | 1,08 | 0,218 |
| Baltic | 1,0 | 0,220 |

(iii) the reactive power provision capability requirement applies at the connection point. For profile shapes other than rectangular, the voltage range represents the highest and lowest values. The full reactive power range is therefore not expected to be available across the range of steady-state voltages;

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

(c) with regard to reactive power capability below maximum capacity, when operating at an active power output below the maximum capacity (P < Pmax), the synchronous power-generating modules shall be capable of operating at every possible operating point in the P-Q-capability diagram of the alternator of that synchronous power-generating module, at least down to minimum stable operating level. Even at reduced active power output, reactive power supply at the connection point shall correspond fully to the P-Q-capability diagram of the alternator of that synchronous power-generating module, taking the auxiliary supply power and the active and reactive power losses of the step-up transformer, if applicable, into account.

*Article 19*

**Requirements for type D synchronous power-generating modules**

1. Type D synchronous power-generating modules shall fulfil the requirements laid down in Article 13, except for Article 13(2)(b), (6) and (7), Article 14 except for Article 14(2), Article 15, except for Article 15(3), Article 16, Article 17, except for Article 17(2) and Article 18.

2. Type D synchronous power-generating modules shall fulfil the following additional requirements in relation to voltage stability:

(a) the parameters and settings of the components of the voltage control system shall be agreed between the powergenerating facility owner and the relevant system operator, in coordination with the relevant TSO;

(b) the agreement referred to in subparagraph (a) shall cover the specifications and performance of an automatic voltage regulator ('AVR') with regard to steady-state voltage and transient voltage control and the specifications and performance of the excitation control system. The latter shall include:

(i) bandwidth limitation of the output signal to ensure that the highest frequency of response cannot excite torsional oscillations on other power-generating modules connected to the network;

(ii) an underexcitation limiter to prevent the AVR from reducing the alternator excitation to a level which would endanger synchronous stability;

(iii) an overexcitation limiter to ensure that the alternator excitation is not limited to less than the maximum value that can be achieved whilst ensuring that the synchronous power-generating module is operating within its design limits;

(iv) a stator current limiter; and

(v) a PSS function to attenuate power oscillations, if the synchronous power-generating module size is above a value of maximum capacity specified by the relevant TSO.

…..

CHAPTER 3

**Requirements for power park modules**

Article 20

**Requirements for type B power park modules**

1. Type B power park modules shall fulfil the requirements laid down in Articles 13, except for Article 13(2)(b), and Article 14.

2. Type B power park modules shall fulfil the following additional requirements in relation to voltage stability:

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

……….

Article 21

**Requirements for type C power park modules**

1. Type C power park modules shall fulfil the requirements listed in Articles 13, except for Article 13(2)(b) and (6), Article 14, except for Article 14(2), Article 15 and Article 20, except for Article 20(2)(a), unless referred to otherwise in point (v) of paragraph 3(d).

………..

3. Type C power park modules shall fulfil the following additional requirements in relation to voltage stability:

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

(b) with regard to reactive power capability at maximum capacity:

(i) the relevant system operator in coordination with the relevant TSO shall specify the reactive power provision capability requirements in the context of varying voltage. To that end, it shall specify a U-Q/Pmax-profile that may take any shape within the boundaries of which the power park module shall be capable of providing reactive power at its maximum capacity;

(ii) the U-Q/Pmax-profile shall be specified by each relevant system operator in coordination with the relevant TSO in conformity with the following principles:

— the U-Q/Pmax-profile shall not exceed the U-Q/Pmax-profile envelope, represented by the inner envelope in Figure 8,

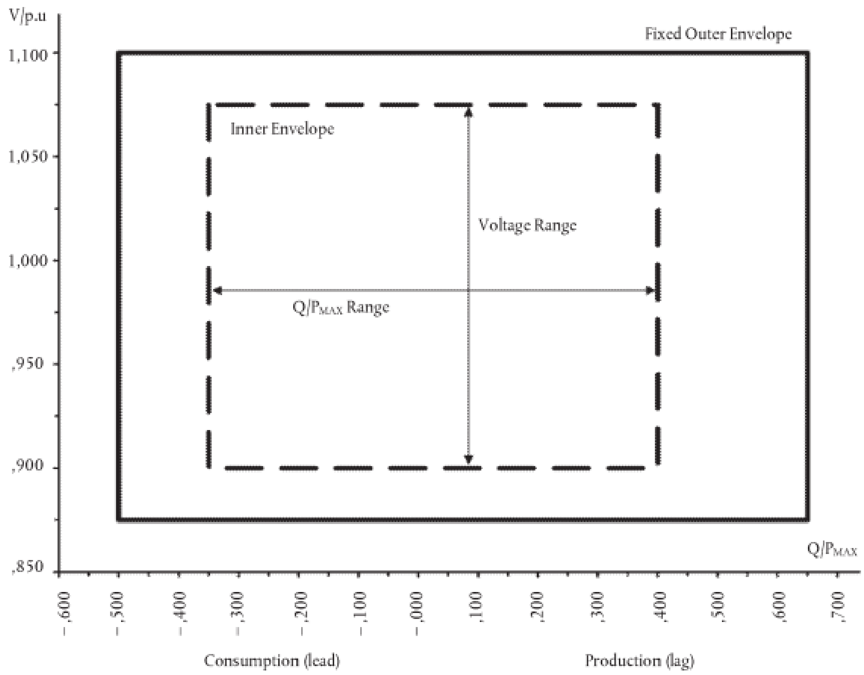
— the dimensions of the U-Q/Pmax-profile envelope (Q/Pmax range and voltage range) shall be within the values specified for each synchronous area in Table 9,

— the position of the U-Q/Pmax-profile envelope shall be within the limits of the fixed outer envelope set out in Figure 8, and

— the specified U-Q/Pmax profile may take any shape, having regard to the potential costs of delivering the capability to provide reactive power production at high voltages and reactive power consumption at low voltages;

*Figure 8*

**U-Q/Pmax-profile of a power park module**




The diagram represents boundaries of a U-Q/Pmax-profile by the voltage at the connection point, expressed by the ratio of its actual value and its reference 1 pu value, against the ratio of the reactive power (Q) and the maximum capacity (Pmax). The position, size and shape of the inner envelope are indicative.

*Table 9*

**Parameters for the inner envelope in Figure 8**

| Synchronous area | Maximum range of $Q/P_{max}$ | Maximum range of steady-state voltage level in PU |
|---|---|---|
| Continental Europe | 0,75 | 0,225 |
| Nordic | 0,95 | 0,150 |
| Great Britain | 0,66 | 0,225 |
| Ireland and Northern Ireland | 0,66 | 0,218 |
| Baltic | 0,80 | 0,220 |

(iii) the reactive power provision capability requirement applies at the connection point. For profile shapes other than rectangular, the voltage range represents the highest and lowest values. The full reactive power range is therefore not expected to be available across the range of steady-state voltages;

(c) with regard to reactive power capability below maximum capacity:

(i) the relevant system operator in coordination with the relevant TSO shall specify the reactive power provision capability requirements and shall specify a P-Q/Pmax-profile that may take any shape within the boundaries of which the power park module shall be capable of providing reactive power below maximum capacity;

(ii) the P-Q/Pmax-profile shall be specified by each relevant system operator in coordination with the relevant TSO, in conformity with the following principles:

— the P-Q/Pmax-profile shall not exceed the P-Q/Pmax-profile envelope, represented by the inner envelope in Figure 9,

— the Q/Pmax range of the P-Q/Pmax-profile envelope is specified for each synchronous area in Table 9,

— the active power range of the P-Q/Pmax-profile envelope at zero reactive power shall be 1 pu,

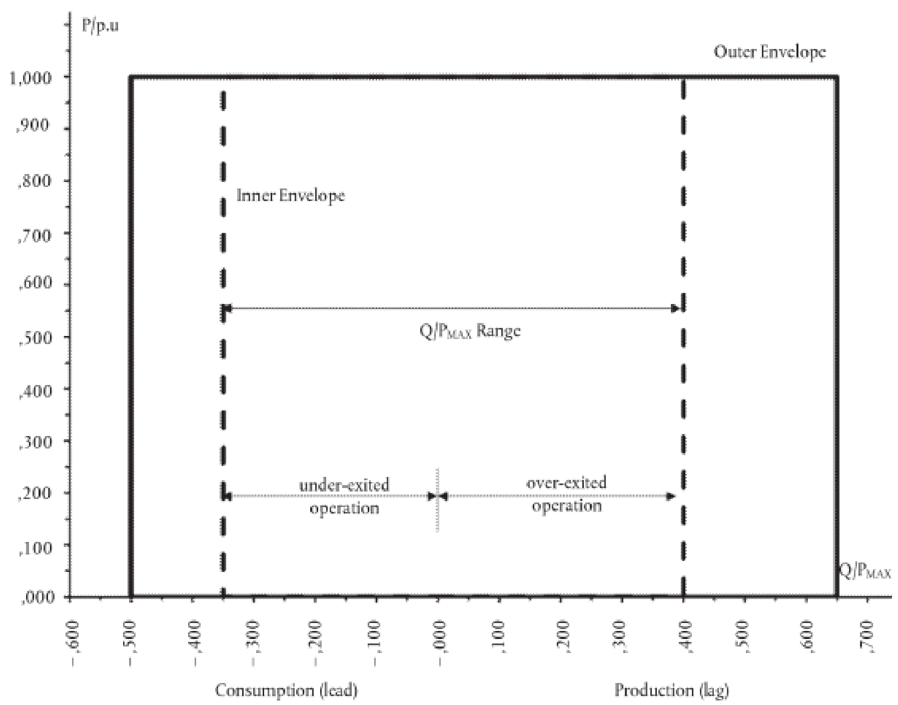
— the P-Q/Pmax-profile can be of any shape and shall include conditions for reactive power capability at zero active power, and

— the position of the P-Q/Pmax-profile envelope shall be within the limits of the fixed outer envelope set out in Figure 9;

(iii) when operating at an active power output below maximum capacity ($P<P_{max}$)the power park module shall be capable of providing reactive power at any operating point inside its P-Q/Pmax-profile, if all units of that power park module which generate power are technically available that is to say they are not out of service due to maintenance or failure, otherwise there may be less reactive power capability, taking into consideration the technical availabilities;

Figure 9

**P-Q/Pmax-profile of a power park module**




The diagram represents boundaries of a P-Q/Pmax-profile at the connection point by the active power, expressed by the ratio of its actual value and the maximum capacity pu, against the ratio of the reactive power (Q) and the maximum capacity (Pmax). The position, size and shape of the inner envelope are indicative.

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

(d) with regard to reactive power control modes:

(i) the power park module shall be capable of providing reactive power automatically by either voltage control mode, reactive power control mode or power factor control mode;

(ii) for the purposes of voltage control mode, the power park module shall be capable of contributing to voltage control at the connection point by provision of reactive power exchange with the network with a setpoint voltage covering 0,95 to 1,05 pu in steps no greater than 0,01 pu, with a slope having a range of at least 2 to 7 % in steps no greater than 0,5 %. The reactive power output shall be zero when the grid voltage value at the connection point equals the voltage setpoint;

(iii) the setpoint may be operated with or without a deadband selectable in a range from zero to ± 5 % of reference 1 pu network voltage in steps no greater than 0,5 %;

(iv) following a step change in voltage, the power park module shall be capable of achieving 90 % of the change in reactive power output within a time t1 to be specified by the relevant system operator in the range of 1 to 5 seconds, and must settle at the value specified by the slope within a time t2 to be specified by the relevant system operator in the range of 5 to 60 seconds, with a steady-state reactive tolerance no greater than 5 % of the maximum reactive power. The relevant system operator shall specify the time specifications;

(vi) for the purpose of reactive power control mode, the power park module shall be capable of setting the reactive power setpoint anywhere in the reactive power range, specified by point (a) of Article 20(2) and by points (a) and (b) of Article 21(3), with setting steps no greater than 5 MVAr or 5 % (whichever is smaller) of full reactive power, controlling the reactive power at the connection point to an accuracy within plus or minus 5 MVAr or plus or minus 5 % (whichever is smaller) of the full reactive power;

(vii) for the purpose of power factor control mode, the power park module shall be capable of controlling the power factor at the connection point within the required reactive power range, specified by the relevant system operator according to point (a) of Article 20(2) or specified by points (a) and (b) of Article 21(3), with a target power factor in steps no greater than 0.01. The relevant system operator shall specify the target power factor value, its tolerance and the period of time to achieve the target power factor following a sudden change of active power output. The tolerance of the target power factor shall be expressed through the tolerance of its corresponding reactive power. This reactive power tolerance shall be expressed by either an absolute value or by a percentage of the maximum reactive power of the power park module;

(viii) the relevant system operator, in coordination with the relevant TSO and with the power park module owner, shall specify which of the above three reactive power control mode options and associated setpoints is to apply, and what further equipment is needed to make the adjustment of the relevant setpoint operable remotely;

…………….

(f) with regard to power oscillations damping control, if specified by the relevant TSO a power park module shall be capable of contributing to damping power oscillations. The voltage and reactive power control characteristics of power park modules must not adversely affect the damping of power oscillations.

*Article 22*

**Requirements for type D power park modules**

Type D power park modules shall fulfil the requirements listed in Articles 13, except for Article 13(2)(b), (6) and (7), Article 14, except for Article 14(2), Article 15, except for Article 15(3), Article 16, Article 20 except for Article 20(2)(a) and Article 21.

*CHAPTER 4*

**Requirements for offshore power park modules**

*Article 23*

**General provisions**

1. The requirements set out in this Chapter apply to the connection to the network of AC-connected power park modules located offshore. An AC-connected power park module located offshore which does not have an offshore connection point shall be considered as an onshore power park module and thus shall comply with the requirements governing power park modules situated onshore.

2. The offshore connection point of an AC-connected offshore power park module shall be specified by the relevant system operator.

3. AC-connected offshore power park modules within the scope of this Regulation shall be categorised in accordance with the following offshore grid connection system configurations:

   (a) configuration 1: AC connection to a single onshore grid interconnection point whereby one or more offshore power park modules that are interconnected offshore to form an offshore AC system are connected to the onshore system;

   (b) configuration 2: meshed AC connections whereby a number of offshore power park modules are interconnected offshore to form an offshore AC system and the offshore AC system is connected to the onshore system at two or more onshore grid interconnection points.

…………..

Article 25

**Voltage stability requirements applicable to AC-connected offshore power park modules**

1. Without prejudice to point (a) of Article 14(3) and point (a) of Article 16(3), an AC-connected offshore power park module shall be capable of staying connected to the network and operating within the ranges of the network voltage at the connection point, expressed by the voltage at the connection point related to reference 1 pu voltage, and for the time periods specified in Table 10.

2. Notwithstanding the provisions of paragraph 1, the relevant TSO in Spain may require AC-connected offshore power park modules to remain connected to the network in the voltage range between 1,05 pu and 1,0875 pu for an unlimited period.

3. Notwithstanding the provisions of paragraph 1, the relevant TSOs in the Baltic synchronous area may require AC connected offshore power park modules to remain connected to the 400 kV network in the voltage range and for the time periods that apply to the Continental Europe synchronous area.

*Table 10*

| Synchronous area | Voltage range | Time period for operation |
|---|---|---|
| Continental Europe | 0,85 pu-0,90 pu | 60 minutes |
| | 0,9 pu-1,118 pu (*) | Unlimited |
| | 1,118 pu-1,15 pu (*) | To be specified by each TSO, but not less than 20 minutes and not more than 60 minutes |
| | 0,90 pu-1,05 pu (**) | Unlimited |
| | 1,05 pu-1,10 pu (**) | To be specified by each TSO, but not less than 20 minutes and not more than 60 minutes |
| Nordic | 0,90 pu-1,05 pu | Unlimited |
| | 1,05 pu-1,10 pu (*) | 60 minutes |
| | 1,05 pu-1,10 pu (**) | To be specified by each TSO, but not more than 60 minutes |
| Great Britain | 0,90 pu-1,10 pu (*) | Unlimited |
| | 0,90 pu-1,05 pu (**) | Unlimited |
| | 1,05 pu-1,10 pu (**) | 15 minutes |
| Ireland and Northern Ireland | 0,90 pu-1,10 pu | Unlimited |
| Baltic | 0,85 pu-0,90 pu (*) | 30 minutes |
| | 0,90 pu-1,118 pu (*) | Unlimited |
| | 1,118 pu-1,15 pu (*) | 20 minutes |
| | 0,88 pu-0,90 pu (**) | 20 minutes |
| | 0,90 pu-1,097 pu (**) | Unlimited |
| | 1,097 pu-1,15 pu (**) | 20 minutes |

(*) The voltage base for pu values is below 300 kV.
(**) The voltage base for pu values is from 300 kV to 400 kV.

The table shows the minimum period during which an AC-connected offshore power park module must be capable of operating over different voltage ranges deviating from the reference 1 pu value without disconnecting.

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.

5. The reactive power capability at maximum capacity specified in point (b) of Article 21(3) shall apply to AC connected offshore power park modules, except for Table 9. Instead, the requirements of Table 11 shall apply.

Table 11

**Parameters for Figure 8**

| Synchronous area | Maximum range of $Q/P_{max}$ | Maximum range of steady-state voltage level in PU |
|---|---|---|
| Continental Europe | 0,75 | 0,225 |
| Nordic | 0,95 | 0,150 |
| Great Britain | 0 (*)<br>0,33 (**) | 0,225 |
| Ireland and Northern Ireland | 0,66 | 0,218 |
| Baltic | 0,8 | 0,22 |

(*) At the offshore connection point for configuration 1.
(**) At the offshore connection point for configuration 2.

## Annex 2 - Proposed Grid Code Legal Text

This section contains the proposed legal text to give effect to the proposals. The proposed new text is colour coded according to the following key.

Key

1) Blue Text – From Grid Code
2) Black Text – Changes / Additional words
3) Orange/ Brown text – From RfG
4) Highlighted Green text – Questions for Stakeholders / Consultation
5) Highlighted yellow text – Nomenclature / Table / Figure numbers – to be finalised when more detail has been added

**DRAFT REACTIVE CAPABILITY / VOLTAGE CONTROL LEGAL TEXT**

### GLOSSARY AND DEFINITIONS

A complete review of the Glossary and Definitions will be required when the full suite of European Codes has been implemented. The current assumption is to use GB definitions where appropriate with use of European definitions where required. The current European definitions used in the text are summarised below but it should be stressed that this is very much work in progress and further revisions will be required in the future. It should be noted that consistency checks will be required between the terms used in the Grid Code and those used in the Distribution Code.

| Term | Definition |
|---|---|
| **Power-Generating Module** | Either a **Synchronous Power-Generating Module** or a **Power Park Module** |
| **Synchronous Power-Generating Module** | An indivisible set of installations which can generate electrical energy such that the frequency of the generated voltage, the generator speed and the frequency of network voltage are in a constant ratio and thus in synchronism. For the avoidance of doubt a **Synchronous Power Generating Module** could comprise of one or more **Generating Unit** or **Alternator** |
| **Connection Point** | The interface at which the **Power-Generating Module**, demand facility, distribution system or HVDC system is connected to a **Transmission System**, offshore network, distribution system, including closed distribution systems, or HVDC system, as identified in the **Connection Agreement**. For the avoidance of doubt a **Connection Point** would include a **Grid Entry Point**, an **Onshore Grid Entry Point**, an **Offshore Grid Entry Point**, a **User System Entry Point** or a **Grid Supply Point**. |
| **Maximum Capacity or 'Pmax'** | The maximum continuous **Active Power** which a **Power-Generating Module** can produce, less any demand associated solely with facilitating the operation of that **Power-Generating Module** and not fed into the network as specified in the **Connection Agreement** or as agreed between the **Relevant System Operator** and the **Generator**. ~~power-generating facility owner~~ |
| **Onshore Synchronous** | An **Onshore Generating Unit** including, for the avoidance of doubt, a **CCGT Unit** in which, under all steady state |

| | |
|---|---|
| **Generating Unit** | conditions, the rotor rotates at a mechanical speed equal to the electrical frequency of the **National Electricity Transmission System** divided by the number of pole pairs of the **Generating Unit**. For the avoidance of doubt an **Onshore Synchronous Generating Unit** includes an alternator. |
| **AC Connected Configuration 1 Offshore Power Park Module** | One or more **Offshore Power Park Modules** that are connected to an AC **Offshore Transmission System** and that AC **Offshore Transmission System** is connected to only one **Onshore Transmission System** substation. |
| **AC Connected Configuration 2 Offshore Power Park Module** | One or more **Offshore Power Park Modules** that are connected to a meshed AC **Offshore Transmission System** and that **AC Offshore Transmission System** is connected to two or more **Onshore Transmission System** substations. |

## PLANNING CODE

PC.A.3.2.2 (f) **Generator Performance Chart**

(i) At the **Onshore Synchronous Generating Unit** stator terminals and at the **Connection Point**

……

## CONNECTION CONDITIONS

Grid Voltage Variations

ECC.6.1.4 Subject as provided below, the voltage on the 400kV part of the **National Electricity Transmission System** at each **Connection Site** with a **User** (and in the case of **OTSDUW Plant and Apparatus**, a **Transmission Interface Point**) will normally remain within ±5% of the nominal value unless abnormal conditions prevail. The minimum voltage is -10% and the maximum voltage is +10% unless abnormal conditions prevail, but voltages between +5% and +10% will not last longer than 15 minutes unless abnormal conditions prevail. Voltages on the 275kV and 110~~132~~kV parts of the **National Electricity Transmission System** at each **Connection Site** with a **User** (and in the case of **OTSDUW Plant and Apparatus**, a **Transmission Interface Point**) will normally remain within the limits ±10% of the nominal value unless abnormal conditions prevail. At nominal **System** voltages below 110~~132~~kV the voltage of the **National Electricity Transmission System** at each **Connection Site** with a **User** (and in the case of **OTSDUW Plant and Apparatus**, a **Transmission Interface Point**) will normally remain within the limits ±6% of the nominal value unless abnormal conditions prevail. Under fault conditions, voltage may collapse transiently to zero at the point of fault until the fault is cleared. The normal operating ranges of the **National Electricity Transmission System** are summarised below:

| National Electricity Transmission System Nominal Voltage | Normal Operating Range | Time period for Operation |
|---|---|---|

| | | |
|---|---|---|
| 400kV | 400kV ±5%<br><br>400kV +5% to +10% | Unlimited<br><br>15 minutes |
| 275kV | 275kV ±10% | Unlimited |
| 132kV | 132kV ±10% | Unlimited |
| 110kV | 110kV ±10% | Unlimited |
| Below 110kV | Below 110kV ±6% | Unlimited |

**NGET** and a **User** may agree ~~greater or lesser~~ wider variations or longer minimum time periods of operation in voltage to those set out above in relation to a particular **Connection Site**, and insofar as a greater ~~or lesser~~ variation is agreed, the relevant figure set out above shall, in relation to that **User** at the particular **Connection Site**, be replaced by the figure agreed.

ECC.6.3.1 GENERAL **POWER GENERATING MODULE** (AND **OTSDUW**) REQUIREMENTS

ECC.6.3.1.1 This section sets out the technical and design criteria and performance requirements for **Type A, Type B, Type C** and **Type D Power Generating Modules** ~~**DC Converters** and **Power Park Modules**~~ (whether directly connected to the **National Electricity Transmission System** or **Embedded**) and (where provided in this section) **OTSDUW Plant and Apparatus** which each **Generator** ~~or **DC Converter Station**~~ owner must ensure are complied with in relation to its AC connected **Power Generating Modules** ~~**Generating Units**, **DC Converters** and **Power Park Modules**~~ and **OTSDUW Plant and Apparatus** ~~but does not apply to **Small Power Stations** or individually to **Power Park Units**~~. References to **Type A**, **Type B**, **Type C** and **Type D Power Generating Modules** ~~**Units**, **DC Converters** and **Power Park Modules**~~ in this ECC.6.3 should be read accordingly. For the avoidance of doubt, the requirements applicable to **Type A** and **Type B Power Generating Modules** owned by **Generators** not subject to a **Bilateral Agreement** and without a **CUSC Contract**, would be required to satisfy the requirements specified in the **Distribution Code**.

ECCC.6.3.1.2 Notwithstanding the requirements of ECC.6.3.1.1, as new types of **Power Generating Modules** merge in the future, **NGET** may reasonably require additional **Plant** performance requirements where the current requirements are insufficient for managing security of supply. Any additional requirements would be pursuant to the terms of the **Connection Agreement**.

ECC.6.3.1.3 For the avoidance of doubt the requirements for **HVDC Systems**, **DC Connected Power Park Modules**, **DC Converters**, **DC Converter Stations** and **OTSDUW DC Converters** are contained are defined in ECC.6.X.X.X

ECC.6.3.2 REACTIVE CAPABILITY

ECC.6.3.2.1 Reactive Capability for **Type B Synchronous Power Generating Modules**

ECC.6.3.2.1.1 When supplying **Rated MW** all **Type B Synchronous Power Generating Modules** must be capable of continuous operation at any points between the limits of 0.95 **Power Factor** lagging and 0.95 **Power Factor** leading at the **Connection Point** unless otherwise specified by **NGET** or relevant **Network Operator** in the **Connection Agreement**. At **Active Power** output levels other than **Rated MW**, all **Generating Units** within a **Type B Synchronous Power Generating Modules** must be capable of continuous operation at any point between the **Reactive Power** capability limits identified on the **Generator Performance Chart** unless otherwise agreed with **NGET** or relevant **Network Operator**.

ECC.6.3.2.2 Reactive Capability for **Type B Power Park Modules**

ECC.6.3.2.2.1 When supplying **Rated MW** all **Type B Power Park Modules** must be capable of continuous operation at any points between the limits of 0.95 **Power Factor** lagging and 0.95 **Power Factor** leading at the **Connection Point** unless otherwise specified by **NGET** or relevant **Network Operator** in the **Connection Agreement**. At **Active Power** output levels other than **Rated MW**, the **Reactive Power** capability limits shall be specified by **NGET** or relevant **Network Operator** pursuant to the terms of the **Connection Agreement**.

ECC.6.3.2.3 Reactive Capability for **Type C** and **D Synchronous Power Generating Modules**

ECC.6.3.2.3.1 **NGET** or the **Relevant Network Operator** may specify if supplementary **Reactive Power** is to be provided if the **Connection Point** of a **Synchronous Power Generating Module** is neither located at the high voltage terminals of the step up transformer to the voltage level of the **Connection Point** nor at the **Generating Unit** ~~**Alternator**~~ terminals, if the high voltage line or cable between the high voltage terminals of the step-up transformer of the **Synchronous Power Generating Module** or its **Generating Unit** ~~**Alternator**~~ terminals if no step-up transformer exists, and the **Connection Point** and shall be provided by the responsible owner of that line or cable. Any such requirement would be pursuant to the terms of the **Connection Agreement**.

ECC.6.3.2.3.3 All **Type C** and **Type D Synchronous Power Generating Modules** shall be capable of satisfying the **Reactive Power** capability requirements at the **Connection Point** as defined in Figure X1 when operating at **Maximum Capacity**.

ECC.6.3.2.3.4 At **Active Power** output levels other than **Maximum Capacity** all **Generating Units** within a **Synchronous Power Generating Module** must be capable of continuous operation at any point between the **Reactive Power** capability limit identified on the **Generator Performance Chart** at least down to the **Designed Minimum Operating Level**. At reduced **Active Power** output, **Reactive Power** supply at the **Connection Point** shall correspond to the **Generator Performance Chart** of the **Generating Unit** ~~Alternator~~ within that **Synchronous Power Generating Module**, taking the auxiliary supplies and the **Active Power** and **Reactive Power** losses of the **Generating Unit** transformer or **Station Transformer** into account.

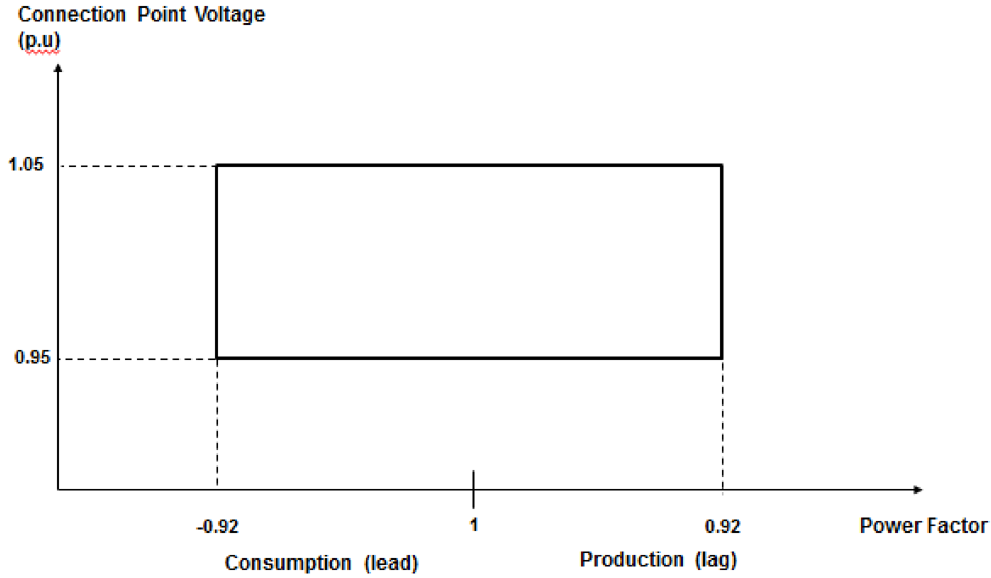



Figure X1

ECC.6.3.2.3.5 In addition, to the requirements of ECC.6.3.2.3.1 – ECC.6.3.2.3.4 the short circuit ratio of all **Onshore Synchronous Generating Units** with an **Apparent Power** rating of less than 1600MVA shall not be less than 0.5. The short circuit ratio of **Onshore Synchronous Generating Units** with a rated **Apparent Power** of 1600MVA or above shall be not less than 0.4.

ECC.6.3.2.6 Reactive Capability for **Type C** and **D Power Park Modules** and **OTSDUW Plant and Apparatus** at the **Interface Point**

ECC.6.3.2.6.1 **NGET** or the **Relevant Network Operator** may specify if supplementary **Reactive Power** is to be provided if the **Connection Point** of a **Power Park Module** is neither located at the high voltage terminals of the step up transformer to the voltage level of the **Connection Point** nor at the **Power Park Unit** terminals, if no step-up transformer exists. This supplementary **Reactive Power** shall compensate the reactive power demand of the high voltage line or cable between the high voltage terminals of the step up transformer of the **Power Park Module** or its **Power Park Unit** terminals, if no step up transformer exists at the **Connection Point** any additional reactive compensation equipment shall be provided by the responsible owner of that line or cable. Any such requirement would be pursuant to the terms of the **Connection Agreement**.

ECC.6.3.2.6.2 All **Type C** and **Type D Power Park Modules** with a **Connection Point** voltage above 33kV, or **OTSDUW Plant and Apparatus**, shall be capable of satisfying the **Reactive Power** capability requirements at the **Connection Point** (or **Interface Point** in the case of **OTSDUW Plant and Apparatus**) as defined in Figure X2 when operating at **Maximum Capacity** (or **Interface Point Capacity** in the case of **OTSUW Plant and Apparatus**).

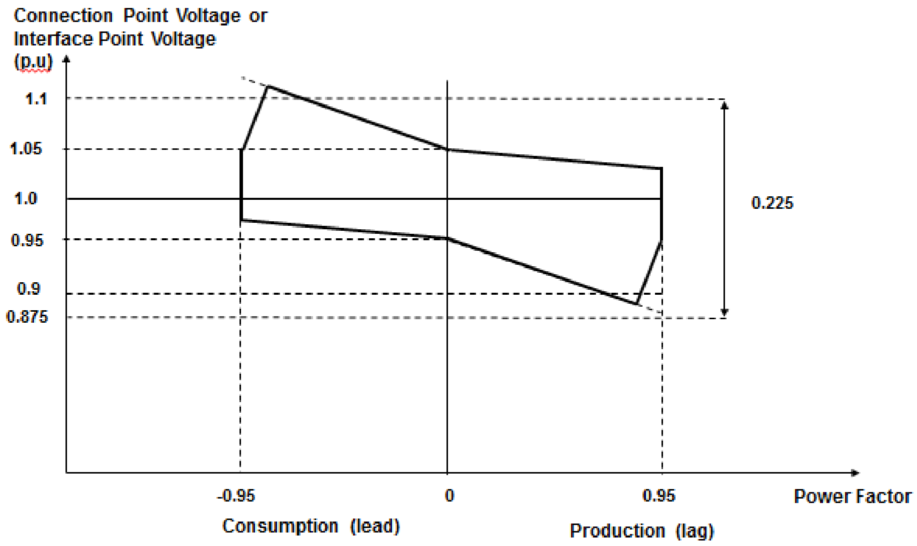



Figure X2

ECC.6.3.2.6.3 All **Type C or Type D Power Park Modules** with a **Connection Point** voltage at or below 33kV shall be capable of satisfying the **Reactive Power** capability requirements at the **Connection Point** as defined in Figure X3 when operating at **Maximum Capacity**.

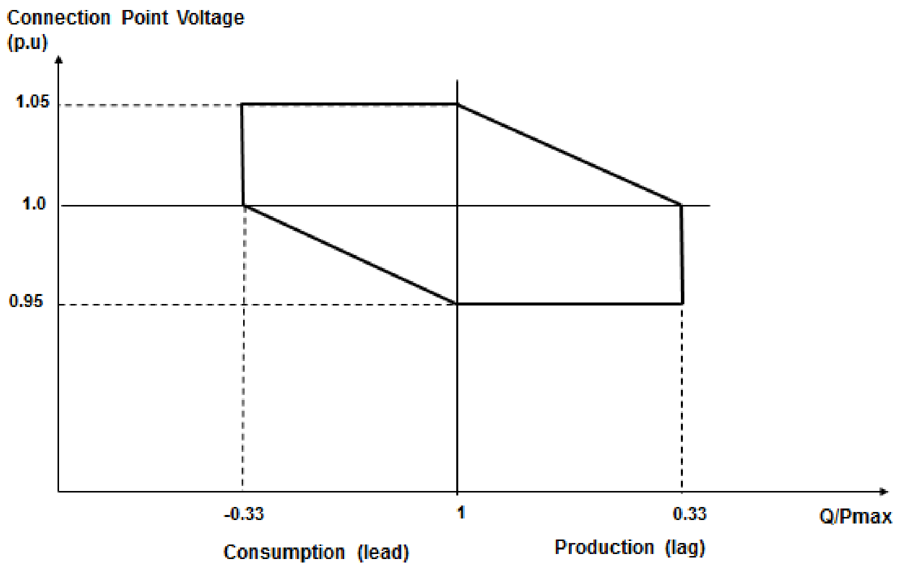



Figure X3

ECC.6.3.2.6.4 All **Type C** and **Type D Power Park Modules**, or **OTSDUW Plant and Apparatus**, shall be capable of satisfying the **Reactive Power** capability requirements at the **Connection Point** (or **Interface Point Capacity** in the case of **OTSUW Plant and Apparatus**) as defined in Figure X4 when operating below **Maximum Capacity**. With all **Plant** in service, the **Reactive Power** limits will reduce linearly below 50% **Active Power** output as shown in Figure X4 unless the requirement to maintain the **Reactive Power** limits defined at **Rated MW** (or **Interface Point Capacity** in the case of **OTSDUW Plant and Apparatus**) under absorbing **Reactive Power** conditions down to 20% **Active Power** output is specified in the **Bilateral Agreement**. These **Reactive Power** limits will be reduced pro rata to the amount of **Plant** in service.

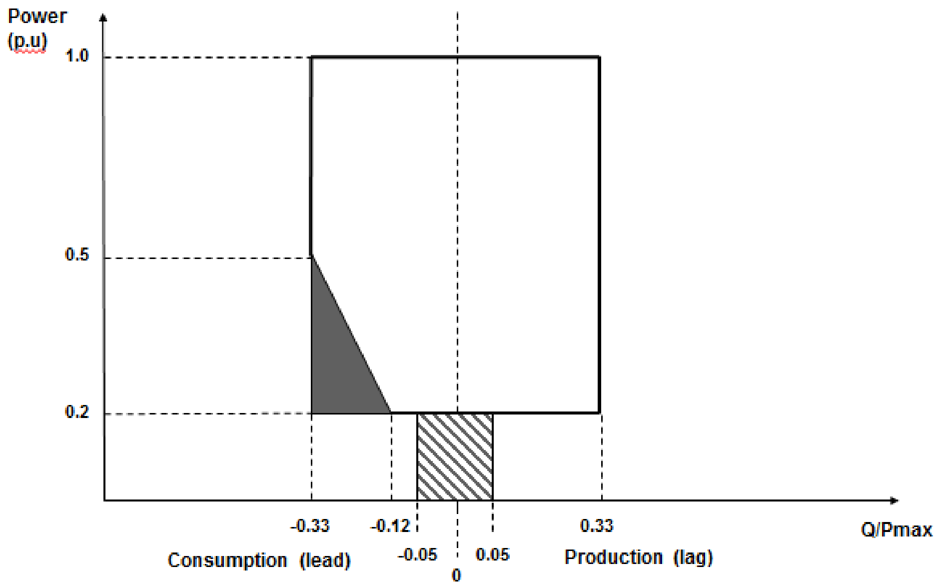



Figure X4

ECC.6.3.2.7 <u>Reactive Capability for **Offshore Synchronous Power Generating Modules** and **Configuration 1, AC connected Offshore Power Park Modules**</u>

ECC.6.3.2.7.1 The short circuit ratio of any **Offshore Synchronous Generating Units** at a **Large Power Station** shall not be less than 0.5. All **Offshore Synchronous Generating Units** and **Configuration 1 AC connected Offshore Power Park Modules** must be capable of maintaining zero transfer of **Reactive Power** at the **Offshore Connection Point**. The steady state tolerance on **Reactive Power** transfer to and from an **Offshore Transmission System** expressed in **MVAr** shall be no greater than 5% of the **Rated MW**.

ECC.6.3.2.7.2 For the avoidance of doubt if a **Generator** wishes to provide a **Reactive Power** capability in excess of the minimum requirements defined in ECC.6.3.2.7.1 it could consider the use of a commercial agreement between the **Generator**, **Offshore Transmission Licensee** and **NGET or the Relevant Network Operator** subject to the most economical solution.

ECC.6.3.2.8 <u>Reactive Capability for **Configuration 2, AC connected Offshore Power Park Modules**</u>

ECC.6.3.2.8.1 All **Configuration 2, AC connected Offshore Power Park Modules** shall be capable of satisfying the **Reactive Power** capability requirements at the **Offshore Connection Point** as defined in Figure X5 when operating at **Maximum Capacity.**

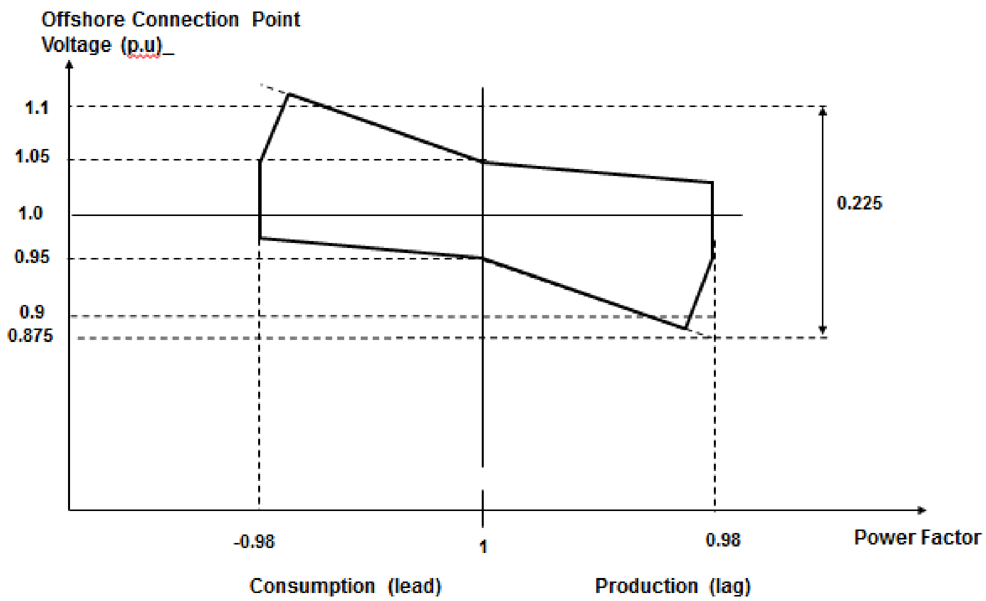



Figure X5

ECC.6.3.2.8.2 All **AC Connected Configuration 2 Offshore Power Park Modules** shall be capable of satisfying the **Reactive Power** capability requirements at the **Offshore Connection Point** as defined in Figure X6 when operating below **Maximum Capacity**. With all **Plant** in service, the **Reactive Power** limits will reduce linearly below 50% **Active Power** output as shown in Figure X6 unless the requirement to maintain the **Reactive Power** limits defined at **Rated MW** (or **Interface Point Capacity** in the case of **OTSDUW Plant and Apparatus**) under absorbing **Reactive Power** conditions down to 20% **Active Power** output is specified in the **Bilateral Agreement**. These **Reactive Power** limits will be reduced pro rata to the amount of Plant in service.

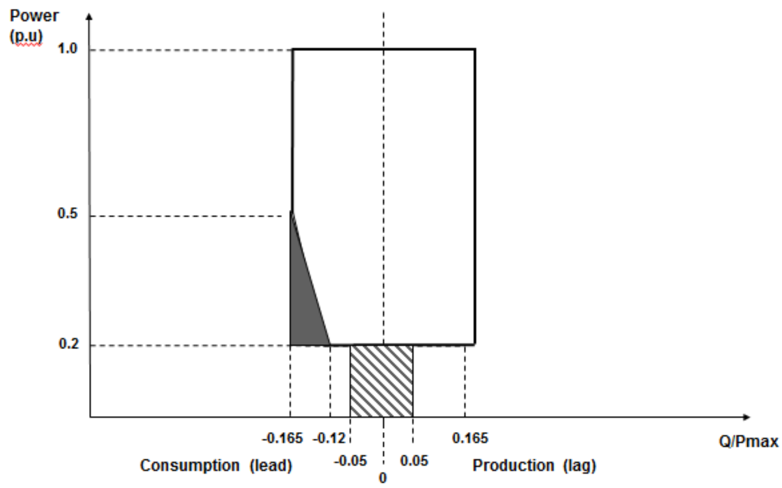



Figure X6

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ECC.6.3.4 ACTIVE POWER OUTPUT UNDER SYSTEM VOLTAGE VARIATIONS

ECC.6.3.4.1 At the **Connection Point**, the **Active Power** output under steady state conditions of any **Power Generating Module** directly connected to the **National Electricity Transmission System** or in the case of **OTSDUW**, the **Active Power** transfer at the **Interface Point**, under steady state conditions of any **OTSDUW Plant and Apparatus** should not be affected by voltage changes in the normal operating range specified in paragraph ECC.6.1.4 by more than the change in **Active Power** losses at reduced or increased voltage.

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ECC.6.3.6 MODULATION OF ACTIVE AND REACTIVE POWER

ECC.6.3.6.1 Each **Power Generating Module** must be capable of contributing to **Frequency** control by continuous modulation of **Active Power** supplied to the **National Electricity Transmission System** or the **User System** in which it is **Embedded**. For the avoidance of doubt each **OTSDUW DC Converter** shall provide each **User** in respect of its **Offshore Power Stations** connected to and/or using an **Offshore Transmission System** a continuous signal indicating the real time **Frequency** measured at the **Transmission Interface Point**. *(This section of text will also be duplicated in the frequency text).*

ECC.6.3.6.2 Each **Power Generating Module** (and **OTSDUW Plant and Apparatus** at a **Transmission Interface Point**) must be capable of contributing to voltage control by continuous changes to the **Reactive Power** supplied to the **National Electricity Transmission System** or the **User System** in which it is **Embedded**.

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ECC.6.3.8 EXCITATION AND VOLTAGE CONTROL PERFORMANCE REQUIREMENTS

ECC.6.3.8.1 Excitation Performance Requirements for **Type B Synchronous Power Generating Modules**

ECC.6.3.8.1.1 Each **Type B Synchronous Power Generating Module** shall be equipped with a permanent automatic excitation control system that can provide constant **Generating Unit** terminal voltage at a selectable setpoint without instability over the entire operating range of the **Type B Synchronous Power Generating Module**.

ECC.6.3.8.1.2 In addition to the requirements of ECC.6.3.8.1.1, **NGET** or the relevant **Network Operator** will specify in the **Connection Agreement** if the control system of the **Type B Synchronous Power Generating Module** shall contribute to voltage control or **Reactive Power** control or **Power Factor** control at the **Connection Point** (or other defined busbar). The performance requirements of the control system including droop (where applicable) shall be specified in the **Connection Agreement**.

ECC.6.3.8.2 Voltage Control Requirements for **Type B Power Park Modules**

ECC.6.3.8.2.1 **NGET** or the relevant **Network Operator** will specify in the **Connection Agreement** if the control system of the **Type B Power Park Module** shall contribute to voltage control or **Reactive Power** control or **Power Factor** control at the **Connection Point** (or other defined busbar). The performance requirements of the control system including droop (where applicable) shall be specified in the **Connection Agreement**.

ECC.6.3.8.3 <u>Excitation Performance Requirements for **Type C** and **Type D Onshore Synchronous Power Generating Modules**</u>

ECC.6.3.8.3.1 **Type C** and **Type D Onshore Synchronous Power Generating Modules** shall be equipped with a permanent automatic excitation control system that can provide constant **Generating Unit** terminal voltage at a selectable setpoint without instability over the entire operating range of the **Synchronous Power Generating Module**.

ECC.6.3.8.3.2 The requirements for excitation control facilities, including **Power System Stabilisers** are specified in ECC.A.6 with any site specific requirements being pursuant to the terms of the **Bilateral Agreement**.

ECC.6.3.8.3.3 Unless otherwise required for testing in accordance with OC5.A.2, the automatic excitation control system of an **Onshore Synchronous Power Generating Module** shall always be operated such that it controls the **Onshore Synchronous Generating Unit** terminal voltage to a value that is

- equal to its rated value: or
- only where provisions have been made in the **Bilateral Agreement**, greater than its rated value.

ECC.6.3.8.3.4 In particular, other control facilities including constant **Reactive Power** output control modes and constant **Power Factor** control modes (but excluding VAR limiters) are not required. However if present in the excitation or voltage control system they will be disabled unless the **Bilateral Agreement** records otherwise. Operation of such control facilities will be in accordance with the provisions contained in **BC2**.

ECC.6.3.8.3.5 The excitation performance requirements for **Offshore Synchronous Power Generating Modules** with an **Offshore Grid Entry Point** shall be specified in the **Bilateral Agreement**.

ECC.6.3.8.4 <u>Voltage Control Performance Requirements for **Type C** and **Type D Onshore Power Park Modules** and **OTSUW Plant and Apparatus** at the **Interface Point**</u>

ECC.6.3.8.4.1 Each **Type C** and **Type D Power Park Module** (and **OTSDUW Plant and Apparatus**) shall be fitted with a continuously acting automatic control system to provide control of the voltage at the **Connection Point** (or **Interface Point** in the case of **OTSDUW Plant and Apparatus**) without instability over the entire operating range of the **Onshore Power Park Module** or **OTSDUW Plant and Apparatus**. Any **Plant or Apparatus** used in the provisions of such voltage control within a **Power Park Module** may be located at the **Power Park Unit** terminals, an appropriate intermediate busbar or the **Connection Point**. **OTSDUW Plant and Apparatus** used in the provision of such voltage control may be located at the **Offshore Grid Entry Point** an appropriate intermediate busbar or at the **Interface Point**. When operating below 20% Rated MW the automatic control system may continue to provide voltage control using any available reactive capability. If voltage control is not being provided the automatic control system shall be designed to ensure a smooth transition between the shaded area bound by CD and the non-shaded area bound by AB in Figure X4 of ECC.6.3.2.6.4.

ECC.6.3.8.4.2 The performance requirements for a continuously acting automatic voltage control system that shall be complied with by the **User** in respect of **Onshore Power Park Modules** (and **OTSDUW Plant and Apparatus** at the **Interface Point**) are defined in ECC.A.7.

ECC.6.3.8.4.3 In particular, other control facilities, including constant **Reactive Power** output control modes and constant **Power Factor** control modes (but excluding VAR limiters) are not required. However if present in the voltage control system they will be disabled unless the **Bilateral Agreement** records otherwise. Operation of such control facilities will be in accordance with the provisions contained in BC2. Where **Reactive Power** output control modes and constant **Power Factor** control modes have been fitted within the voltage control system they shall be required to satisfy the requirements of ECC.A.7.3.1.

ECC.6.3.8.5 <u>Excitation Control Performance requirements applicable to AC Connected **Offshore Synchronous Power Generating Modules** and voltage control performance requirements applicable AC connected **Offshore Power Park Modules**</u>

ECC.6.3.8.5.1 A continuously acting automatic control system is required to provide control of **Reactive Power** (as specified in ECC.6.3.2.7) at the **Offshore Connection Point** without instability over the entire operating range of the AC connected **Offshore Synchronous Power Generating Module** or **Configuration 1 AC connected Offshore Power Park Module**. The performance requirements for this automatic control system will be specified in the **Bilateral Agreement**.

ECC.6.3.8.5.2 A continuously acting automatic control system is required to provide control of **Reactive Power** (as specified in ECC.6.3.2.8) at the **Offshore Connection Point** without instability over the entire operating range of the **Configuration 2 AC connected Offshore Power Park Module**. The performance requirements for this automatic control system are specified in ECC.A.8

ECC.6.3.8.5.3 In addition to ECC.6.3.8.5.1 and ECC.6.3.8.5.2 the requirements for excitation or voltage control facilities, including **Power System Stabilisers**, where these are necessary for system reasons, will be specified in the **Bilateral Agreement**. Reference is made to on-load commissioning witnessed by **NGET** in BC2.11.2.

ECC.6.3.9 STEADY STATE LOAD INACCURACIES

ECC.6.3.9.1 The standard deviation of **Load** error at steady state **Load** over a 30 minute period must not exceed 2.5 per cent of a **Power Generating Module's** ~~**Genset's Registered**~~ **Maximum Capacity**. Where a **Power Generating Module**~~**Genset**~~ is instructed to **Frequency** sensitive operation, allowance will be made in determining whether there has been an error according to the governor droop characteristic registered under the **PC**.

For the avoidance of doubt in the case of a **Power Park Module** allowance will be made for the full variation of mechanical power output.

ECC.6.3.10 NEGATIVE PHASE SEQUENCE LOADINGS

ECC.6.3.10.1 In addition to meeting the conditions specified in ECC.6.1.5(b), each **Synchronous Power Generating Module**~~**Unit**~~ will be required to withstand, without tripping, the negative phase sequence loading incurred by clearance of a close-up phase-to-phase fault, by **System Back-Up Protection** on the **National Electricity Transmission System** or **User System** located **Onshore** in which it is **Embedded**.

ECC.6.3.11 NEUTRAL EARTHING

ECC.6.3.11.1 At nominal **System** voltages of 110~~132~~kV and above the higher voltage windings of a transformer of a **Power Generating Module** ~~**Generating Unit**, **DC Converter**, **Power Park Module**~~ or transformer resulting from **OTSDUW** must be star connected with the star point suitable for connection to earth. The earthing and lower voltage winding arrangement shall be such as to ensure that the **Earth Fault Factor** requirement of paragraph ECC.6.2.1.1 (b) will be met on the **National Electricity Transmission System** at nominal **System** voltages of 110~~132~~kV and above.

ECC.6.3.12 VOLTAGE AND FREQUENCY SENSITIVE RELAYS

ECC.6.3.12.1 Combined Voltage and Frequency Sensitive Relays

ECC.6.3.12.1.1 As stated in ECC.6.1.3, the **System Frequency** could rise to 52Hz or fall to 47Hz and the **System** voltage at the **Connection Point** could rise or fall within the values outlined in ECC.6.1.4. Each **Power Generating Module** ~~**Generating Unit**, **DC Converter**,~~ or **OTSDUW Plant and Apparatus**~~, Power Park Module~~ or any constituent element must continue to operate within this **Frequency** range for at least the periods of time given in ECC.6.1.3 and voltage range as defined in ECC.6.1.4 unless **NGET** has agreed to any simultaneous overvoltage and underfrequency relays and/or simultaneous undervoltage and over frequency relays or **Frequency**-level relays and/or rate-of-change-of-**Frequency** relays which will trip such **Power Generating Module**, ~~**Generating Unit**, **DC Converter**,~~ or **OTSDUW Plant and Apparatus**~~,~~ ~~**Power Park Module**~~ and any constituent element within this **Frequency** or voltage range, as specified under the **Bilateral Agreement**.

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## APPENDIX E6 - PERFORMANCE REQUIREMENTS FOR CONTINUOUSLY ACTING AUTOMATIC EXCITATION CONTROL SYSTEMS FOR ONSHORE SYNCHRONOUS POWER GENERATING MODULES

ECC.A.6.1 Scope

ECC.A.6.1.1 This Appendix sets out the performance requirements of continuously acting automatic excitation control systems for **Type C** and **Type D** **Onshore Synchronous Power Generating Modules** that must be complied with by the **User**. This Appendix does not limit any site specific requirements that may be included in a **Bilateral Agreement** where in **NGET's** reasonable opinion these facilities are necessary for system reasons.

ECC.A.6.1.2 Where the requirements may vary the likely range of variation is given in this Appendix. It may be necessary to specify values outside this range where **NGET** identifies a system need, and notwithstanding anything to the contrary **NGET** may specify in the **Bilateral Agreement** values outside of the ranges provided in this Appendix 6. The most common variations are in the on-load excitation ceiling voltage requirements and the response time required of the **Exciter**. Actual values will be included in the **Bilateral Agreement**.

ECC.A.6.1.3 Should a **Generator** anticipate making a change to the excitation control system it shall notify **NGET** under the **Planning Code** (PC.A.1.2(b) and (c)) as soon as the **Generator** anticipates making the change. The change may require a revision to the **Bilateral Agreement**.

ECC.A.6.2 Requirements

ECC.A.6.2.1 The **Excitation System** of a **Type C** or **Type D** **Onshore Synchronous Power Generating Module** shall include an excitation source (**Exciter**), a **Power System Stabiliser** and a continuously acting **Automatic Voltage Regulator** (**AVR**) and shall meet the following functional specification.

~~CC.A.6.2.2 In respect of **Onshore Synchronous Generating Units** with a **Completion Date** on or after 1 January 2009, and **Onshore Synchronous Generating Units** with a **Completion Date** before 1 January 2009 subject to a **Modification** to the excitation control facilities where the **Bilateral Agreement** does not specify otherwise, the continuously acting automatic excitation control system shall include a **Power System Stabiliser (PSS)** as a means of supplementary control. The functional specification of the **Power System Stabiliser** is included in CC.A.6.2.5.~~

ECC.A.6.2.3 Steady State Voltage Control

ECC.A.6.2.3.1 An accurate steady state control of the **Onshore Synchronous Power Generating Module** pre-set **Generating Unit** terminal voltage is required. As a measure of the accuracy of the steady-state voltage control, the **Automatic Voltage Regulator** shall have static zero frequency gain, sufficient to limit the change in terminal voltage to a drop not exceeding 0.5% of rated terminal voltage, when the output of a **Generating Unit** within an **Onshore Synchronous Power Generating Module** is gradually changed from zero to rated MVA output at rated voltage, **Active Power** and **Frequency**.

ECC.A.6.2.4 Transient Voltage Control

ECC.A.6.2.4.1 For a step change from 90% to 100% of the nominal **Onshore** **Synchronous Generating Unit** terminal voltage, with the **Onshore** **Synchronous Generating Unit** on open circuit, the **Excitation System** response shall have a damped oscillatory characteristic. For this characteristic, the time for the **Onshore Synchronous Generating Unit** terminal voltage to first reach 100% shall be less than 0.6 seconds. Also, the time to settle within 5% of the voltage change shall be less than 3 seconds.

ECC.A.6.2.4.2 To ensure that adequate synchronising power is maintained, when the **Onshore Power Generating Module** is subjected to a large voltage disturbance, the **Exciter** whose output is varied by the **Automatic Voltage Regulator** shall be capable of providing its achievable upper and lower limit ceiling voltages to the **Onshore Synchronous Generating Unit** field in a time not exceeding that specified in the **Bilateral Agreement**. This will normally be not less than 50 ms and not greater than 300 ms. The achievable upper and lower limit ceiling voltages may be dependent on the voltage disturbance.

ECC.A.6.2.4.3 The **Exciter** shall be capable of attaining an **Excitation System On Load Positive Ceiling Voltage** of not less than a value specified in the **Bilateral Agreement** that will be:

not less than 2 per unit (pu)

normally not greater than 3 pu

exceptionally up to 4 pu

of **Rated Field Voltage** when responding to a sudden drop in voltage of 10 percent or more at the **Onshore Synchronous Generating Unit** terminals. **NGET** may specify a value outside the above limits where **NGET** identifies a system need.

ECC.A.6.2.4.4 If a static type **Exciter** is employed:

(i) the field voltage should be capable of attaining a negative ceiling level specified in the **Bilateral Agreement** after the removal of the step disturbance of ECC.A.6.2.4.3. The specified value will be 80% of the value specified in ECC.A.6.2.4.3. **NGET** may specify a value outside the above limits where **NGET** identifies a system need.

(ii) the **Exciter** must be capable of maintaining free firing when the **Onshore Synchronous Generating Unit** terminal voltage is depressed to a level which may be between 20% to 30% of rated terminal voltage

(iii) the **Exciter** shall be capable of attaining a positive ceiling voltage not less than 80% of the **Excitation System On Load Positive Ceiling Voltage** upon recovery of the **Onshore Synchronous Generating Unit** terminal voltage to 80% of rated terminal voltage following fault clearance. **NGET** may specify a value outside the above limits where **NGET** identifies a system need.

(iv) the requirement to provide a separate power source for the **Exciter** will be specified in the **Bilateral Agreement** if **NGET** identifies a **Transmission System** need.

ECC.A.6.2.5 Power Oscillations Damping Control

ECC.A.6.2.5.1 To allow the **Onshore Power Generating Module** to maintain second and subsequent swing stability and also to ensure an adequate level of low frequency electrical damping power, the **Automatic Voltage Regulator** of each **Onshore Synchronous Generating Unit** within the **Onshore Synchronous Power Generating Module** shall include a **Power System Stabiliser** as a means of supplementary control.

ECC.A.6.2.5.2 Whatever supplementary control signal is employed, it shall be of the type which operates into the **Automatic Voltage Regulator** to cause the field voltage to act in a manner which results in the damping power being improved while maintaining adequate synchronising power.

ECC.A.6.2.5.3 The arrangements for the supplementary control signal shall ensure that the **Power System Stabiliser** output signal relates only to changes in the supplementary control signal and not the steady state level of the signal. For example, if generator electrical power output is chosen as a supplementary control signal then the **Power System Stabiliser** output should relate only to changes in the **Synchronous Generating Unit** electrical power output and not the steady state level of power output. Additionally the **Power System Stabiliser** should not react to mechanical power changes in isolation for example during rapid changes in steady state load or when providing frequency response.

ECC.A.6.2.5.4 The output signal from the **Power System Stabiliser** shall be limited to not more than ±10% of the **Onshore Synchronous Generating Unit** terminal voltage signal at the **Automatic Voltage Regulator** input. The gain of the **Power System Stabiliser** shall be such that an increase in the gain by a factor of 3 shall not cause instability.

ECC.A.6.2.5.5 The **Power System Stabiliser** shall include elements that limit the bandwidth of the output signal. The bandwidth limiting must ensure that the highest frequency of response cannot excite torsional oscillations on other plant connected to the network. A bandwidth of 0-5Hz would be judged to be acceptable for this application.

ECC.A.6.2.5.6 The **Generator** will agree **Power System Stabiliser** settings with **NGET** prior to the on-load commissioning detailed in BC2.11.2(d). To allow assessment of the performance before on-load commissioning the **Generator** will provide to **NGET** a report covering the areas specified in CP.A.3.2.1.

ECC.A.6.2.5.7 The **Power System Stabiliser** must be active within the **Excitation System** at all times when **Synchronised** including when the **Under Excitation Limiter** or **Over Excitation Limiter** are active. When operating at low load when **Synchronising** or **De-Synchronising** an **Onshore Synchronous Generating Unit,** within an **Synchronous Power Generating Modul**e, the **Power System Stabiliser** may be out of service.

ECC.A.6.2.5.8 Where a **Power System Stabiliser** is fitted to a **Pumped Storage Unit** it must function when the **Pumped Storage Unit** is in both generating and pumping modes.

ECC.A.6.2.6 Overall **Excitation System** Control Characteristics

ECC.A.6.2.6.1 The overall **Excitation System** shall include elements that limit the bandwidth of the output signal. The bandwidth limiting must be consistent with the speed of response requirements and ensure that the highest frequency of response cannot excite torsional oscillations on other plant connected to the network. A bandwidth of 0-5 Hz will be judged to be acceptable for this application.

ECC.A.6.2.6.2 The response of the **Automatic Voltage Regulator** combined with the **Power System Stabiliser** shall be demonstrated by injecting similar step signal disturbances into the **Automatic Voltage Regulator** reference as detailed in OC5A.2.2 and OC5.A.2.4. The **Automatic Voltage Regulator** shall include a facility to allow step injections into the **Automatic Voltage Regulator** voltage reference, with the **Onshore Power Generating Module** operating at points specified by **NGET** (up to rated MVA output). The damping shall be judged to be adequate if the corresponding **Active Power** response to the disturbances decays within two cycles of oscillation.

ECC.A.6.2.6.3 A facility to inject a band limited random noise signal into the **Automatic Voltage Regulator** voltage reference shall be provided for demonstrating the frequency domain response of the **Power System Stabiliser**. The tuning of the **Power System Stabiliser** shall be judged to be adequate if the corresponding **Active Power** response shows improved damping with the **Power System Stabiliser** in combination with the **Automatic Voltage Regulator** compared with the **Automatic Voltage Regulator** alone over the frequency range 0.3Hz – 2Hz.

ECC.A.6.2.7 Under-Excitation Limiters

ECC.A.6.2.7.1 The security of the power system shall also be safeguarded by means of MVAr **Under Excitation Limiters** fitted to the generator **Excitation System**. The **Under Excitation Limiter** shall prevent the **Automatic Voltage Regulator** reducing the generator excitation to a level which would endanger synchronous stability. The **Under Excitation Limiter** shall operate when the excitation system is providing automatic control. The **Under Excitation Limiter** shall respond to changes in the **Active Power** (MW) the **Reactive Power** (MVAr) and to the square of the generator voltage in such a direction that an increase in voltage will permit an increase in leading MVAr. The characteristic of the **Under Excitation Limiter** shall be substantially linear from no-load to the maximum **Active Power** output of the **Onshore Power Generating Module** at any setting and shall be readily adjustable.

ECC.A.6.2.7.2 The performance of the **Under Excitation Limiter** shall be independent of the rate of change of the **Onshore Synchronous Power Generating Module** load and shall be demonstrated by testing as detailed in OC5.A.2.5. The resulting maximum overshoot in response to a step injection which operates the **Under Excitation Limiter** shall not exceed 4% of the **Onshore Synchronous Generating Unit** rated MVA. The operating point of the **Onshore Synchronous Power Generating Module** shall be returned to a steady state value at the limit line and the final settling time shall not be greater than 5 seconds. When the step change in **Automatic Voltage Regulator** reference voltage is reversed, the field voltage should begin to respond without any delay and should not be held down by the **Under Excitation Limiter**. Operation into or out of the preset limit levels shall ensure that any resultant oscillations are damped so that the disturbance is within 0.5% of the **Onshore Synchronous Unit Generating** MVA rating within a period of 5 seconds.

ECC.A.6.2.7.3 The **Generator** shall also make provision to prevent the reduction of the **Onshore Synchronous Generating Unit** excitation to a level which would endanger synchronous stability when the **Excitation System** is under manual control.

ECC.A.6.2.8 Over-Excitation and Stator Current Limiters

ECC.A.6.2.8.1 The settings of the **Over-Excitation Limiter** and stator current limiter, ~~where it exists,~~ shall ensure that the **Onshore Synchronous Generating Unit** excitation is not limited to less than the maximum value that can be achieved whilst ensuring the **Onshore Synchronous Generating Unit** is operating within its design limits. If the **Onshore Synchronous Generating Unit** excitation is reduced following a period of operation at a high level, the rate of reduction shall not exceed that required to remain within any time dependent operating characteristics of the **Onshore Synchronous Power Generating Module**.

ECC.A.6.2.8.2 The performance of the **Over-Excitation Limiter**~~, where it exists,~~ shall be demonstrated by testing as described in OC5.A.2.6. Any operation beyond the **Over-Excitation Limit** shall be controlled by the **Over-Excitation Limiter** or stator current limiter without the operation of any **Protection** that could trip the **Onshore Synchronous Power Generating Module**.

CC.A.6.2.8.3 The **Generator** shall also make provision to prevent any over-excitation restriction of the **Onshore Synchronous Generating Unit** when the **Excitation System** is under manual control, other than that necessary to ensure the **Onshore Power Generating Module** is operating within its design limits.

# APPENDIX 7 - PERFORMANCE REQUIREMENTS FOR CONTINUOUSLY ACTING AUTOMATIC VOLTAGE CONTROL SYSTEMS FOR AC CONNECTED ONSHORE ~~NON-SYNCHRONOUS GENERATING UNITS, ONSHORE DC CONVERTERS,~~ POWER PARK MODULES AND OTSDUW PLANT AND APPARATUS AT THE INTERFACE POINT

ECC.A.7.1 Scope

ECC.A.7.1.1 This Appendix sets out the performance requirements of continuously acting automatic voltage control systems for **Onshore** ~~**Non-Synchronous Generating Units**,~~ **Power Park Modules** and **OTSDUW Plant and Apparatus** at the **Interface Point** that must be complied with by the **User**. This Appendix does not limit any site specific requirements that may be included in a **Bilateral Agreement** where in **NGET's** reasonable opinion these facilities are necessary for system reasons.

ECC.A.7.1.2 Proposals by **Generators** to make a change to the voltage control systems are required to be notified to **NGET** under the **Planning Code** (PC.A.1.2(b) and (c)) as soon as the **Generator** anticipates making the change. The change may require a revision to the **Bilateral Agreement**.

ECC.A.7.2 Requirements

ECC.A.7.2.1 **NGET** requires that the continuously acting automatic voltage control system for the ~~**Onshore Non-Synchronous Generating Unit**, **Onshore DC Converter** or~~ **Onshore Power Park Module** or **OTSDUW Plant and Apparatus** shall meet the following functional performance specification. If a **Network Operator** has confirmed to **NGET** that its network to which an **Embedded** ~~**Onshore Non-Synchronous Generating Unit**, **Onshore DC Converter**,~~ **Onshore Power Park Module** or **OTSDUW Plant and Apparatus** is connected is restricted such that the full reactive range under the steady state voltage control requirements (ECC.A.7.2.2) cannot be utilised, **NGET** may specify in the **Bilateral Agreement** alternative limits to the steady state voltage control range that reflect these restrictions. Where the **Network Operator** subsequently notifies **NGET** that such restriction has been removed, **NGET** may propose a **Modification** to the **Bilateral Agreement** (in accordance with the **CUSC** contract) to remove the alternative limits such that the continuously acting automatic voltage control system meets the following functional performance specification. All other requirements of the voltage control system will remain as in this Appendix.

ECC.A.7.2.2 Steady State Voltage Control

ECC.A.7.2.2.1 The ~~**Onshore Non-Synchronous Generating Unit**, **Onshore DC Converter**,~~ **Onshore Power Park Module** or **OTSDUW Plant and Apparatus** shall provide continuous steady state control of the voltage at the **Connection Point** ~~**Onshore Grid Entry Point** (or **Onshore User System Entry Point** if **Embedded**)~~ (or the **Interface Point** in the case of **OTSDUW Plant and Apparatus**) with a **Setpoint Voltage** and **Slope** characteristic as illustrated in Figure ECC.A.7.2.2a. ~~It should be noted that where the **Reactive Power** capability requirement of a directly connected **Onshore Non-Synchronous Generating Unit**, **Onshore DC Converter**, **Onshore Power Park Module** in Scotland, or **OTSDUW Plant and Apparatus** in Scotland as specified in CC.6.3.2 (c), is not at the **Onshore Grid Entry Point** or **Interface Point**, the values of Qmin and Qmax shown in this figure will be as modified by the 33/132kV or 33/275kV or 33/400kV transformer.~~

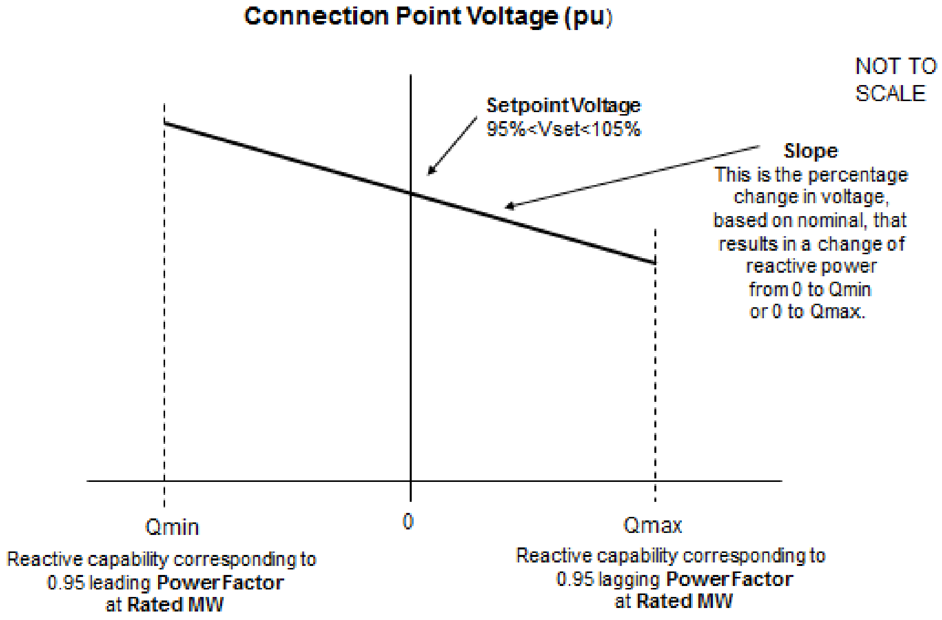



Figure ECC.A.7.2.2a

ECC.A.7.2.2.2 The continuously acting automatic control system shall be capable of operating to a **Setpoint Voltage** between 95% and 105% with a resolution of 0.25% of the nominal voltage. For the avoidance of doubt values of 95%, 95.25%, 95.5% … may be specified, but not intermediate values. The initial **Setpoint Voltage** will be 100%. The tolerance within which this **Setpoint Voltage** shall be achieved is specified in BC2.A.2.6. For the avoidance of doubt, with a tolerance of 0.25% and a Setpoint Voltage of 100%, the achieved value shall be between 99.75% and 100.25%. **NGET** may request the **Generator** to implement an alternative **Setpoint Voltage** within the range of 95% to 105%. For **Embedded Generators** the **Setpoint Voltage** will be discussed between **NGET** and the relevant **Network Operator** and will be specified to ensure consistency with ECC.6.3.4.

ECC.A.7.2.2.3 The **Slope** characteristic of the continuously acting automatic control system shall be adjustable over the range 2% to 7% (with a resolution of 0.5%). For the avoidance of doubt values of 2%, 2.5%, 3% may be specified, but not intermediate values. The initial **Slope** setting will be 4%. The tolerance within which this **Slope** shall be achieved is specified in BC2.A.2.6. For the avoidance of doubt, with a tolerance of 0.5% and a **Slope** setting of 4%, the achieved value shall be between 3.5% and 4.5%. **NGET** may request the **Generator** to implement an alternative slope setting within the range of 2% to 7%. For **Embedded Generators** the **Slope** setting will be discussed between **NGET** and the relevant **Network Operator** and will be specified to ensure consistency with ECC.6.3.4.

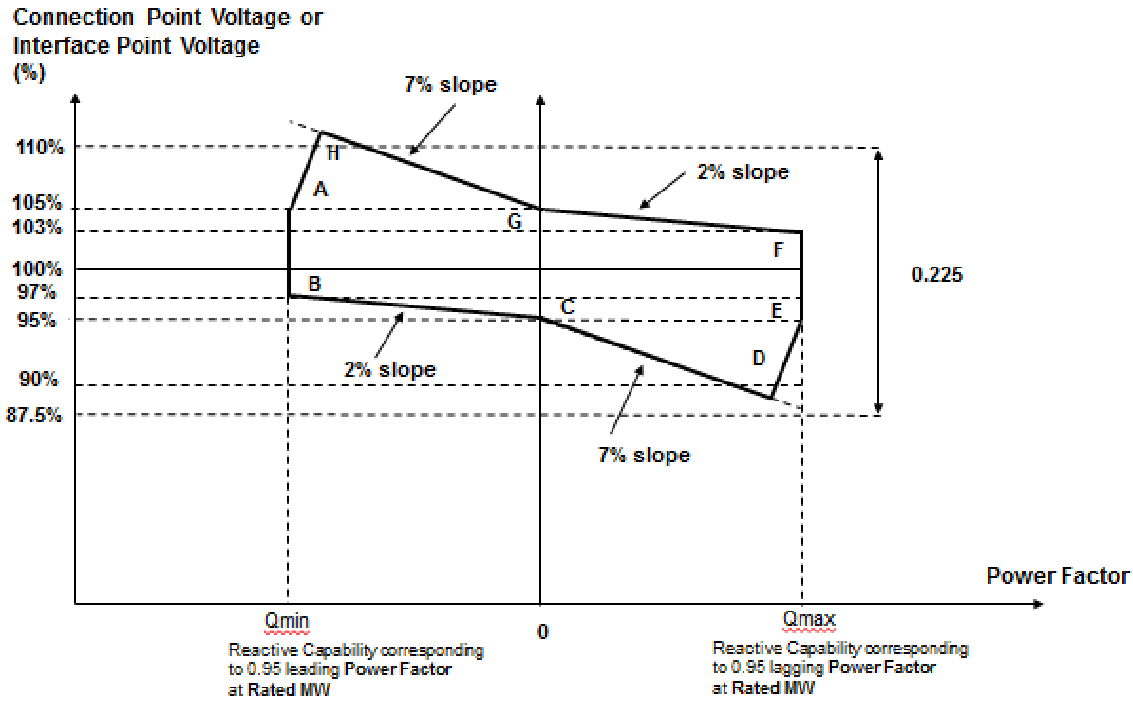



Figure ECC.A.7.2.2b

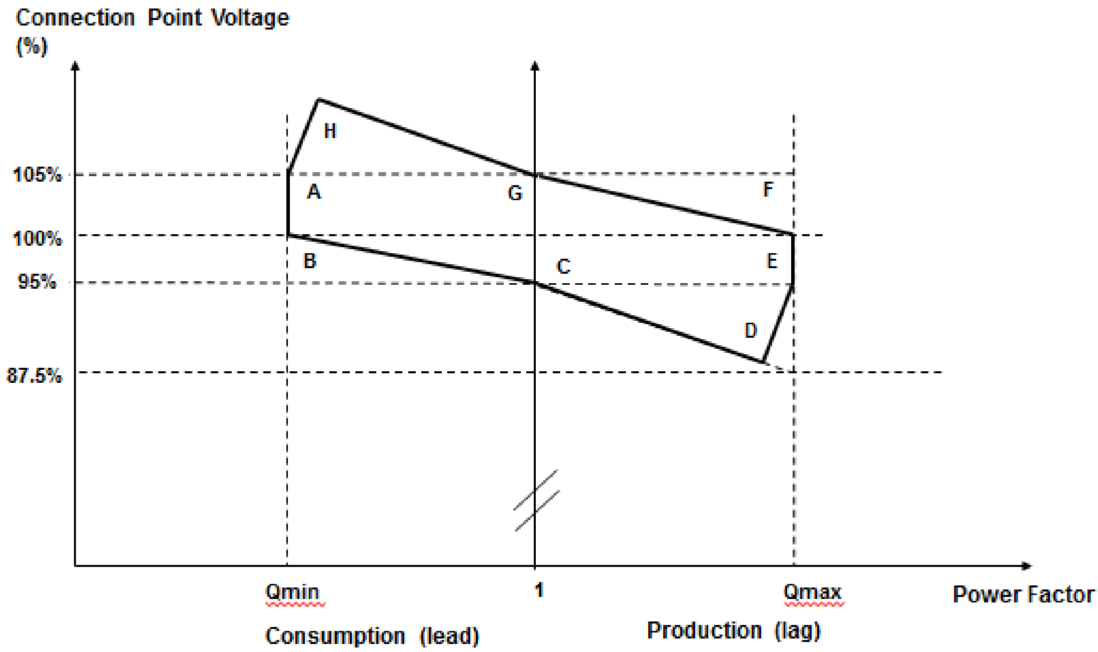



Figure ECC.A.7.2.2c

ECC.A.7.2.2.4 Figure ECC.A.7.2.2b shows the required envelope of operation for ~~**Onshore Non-Synchronous Generating Units**~~, ~~**Onshore DC Converters**~~, **OTSDUW Plant and Apparatus** and **Onshore Power Park Modules** except for those **Embedded** at 33kV and below or directly connected to the **National Electricity Transmission System** at 33kV and below. Figure ECC.A.7.2.2c shows the required envelope of operation for ~~**Onshore Non-Synchronous Generating Units**~~, ~~**Onshore DC Converters** and~~ **Onshore Power Park Modules Embedded** at 33kV and below or directly connected to the **National Electricity Transmission System** at 33kV and below. ~~Where the **Reactive Power** capability requirement of a directly connected **Onshore Non-Synchronous Generating Unit**, **Onshore DC Converter**, **OTSDUW Plant and Apparatus** or **Onshore Power Park Module** in Scotland, as specified in CC.6.3.2 (c), is not at the **Onshore Grid Entry Point** or **Interface Point** in the case of **OTSDUW Plant and Apparatus**, the values of Qmin and Qmax shown in this figure will be as modified by the 33/132kV or 33/275kV or 33/400kV transformer.~~ The enclosed area within points ABCDEFGH is the required capability range within which the **Slope** and **Setpoint Voltage** can be changed.

ECC.A.7.2.2.5 Should the operating point of the ~~**Onshore Non-Synchronous Generating Unit**, **Onshore DC Converter**,~~ **OTSDUW Plant and Apparatus** or **Onshore Power Park Module** deviate so that it is no longer a point on the operating characteristic (figure ECC.A.7.2.2a) defined by the target **Setpoint Voltage** and **Slope**, the continuously acting automatic voltage control system shall act progressively to return the value to a point on the required characteristic within 5 seconds.

ECC.A.7.2.2.6 Should the **Reactive Power** output of the ~~**Onshore Non-Synchronous Generating Unit**, **Onshore DC Converter**,~~ **OTSDUW Plant and Apparatus** or **Onshore Power Park Module** reach its maximum lagging limit at a ~~**Onshore Grid Entry**~~ **Connection Point** voltage ~~(or **Onshore User System Entry Point** voltage if **Embedded**~~ (or **Interface Point** in the case of **OTSDUW Plant and Apparatus**) above 95%, the ~~**Onshore Non-Synchronous Generating Unit**, **Onshore DC Converter**,~~ **OTSDUW Plant and Apparatus** or **Onshore Power Park Module** shall maintain maximum lagging **Reactive Power** output for voltage reductions down to 95%. This requirement is indicated by the line EF in figures ECC.A.7.2.2b and ECC.A.7.2.2c. Should the **Reactive Power** output of the ~~**Onshore Non-Synchronous Generating Unit**, **Onshore DC Converter**,~~ **OTSDUW Plant and Apparatus** or **Onshore Power Park Module** reach its maximum leading limit at ~~a **Onshore Grid Entry**~~ **Connection Point** voltage (~~or **Onshore User System Entry Point** voltage if **Embedded**~~ or **Interface Point** in the case of **OTSDUW Plant and Apparatus**) below 105%, the ~~**Onshore Non-Synchronous Generating Unit**, **Onshore DC Converter**,~~ **OTSDUW Plant and Apparatus** or **Onshore Power Park Module** shall maintain maximum leading **Reactive Power** output for voltage increases up to 105%. This requirement is indicated by the line AB in figures ECC.A.7.2.2b and ECC.A.7.2.2c.

ECC.A.7.2.2.7 For **Onshore** ~~**Grid Entry**~~ **Connection** **Point** voltages (~~or **Onshore User System Entry Point** voltages if Embedded~~ or **Interface Point** voltages) below 95%, the lagging **Reactive Power** capability of the ~~**Onshore Non-Synchronous Generating Unit**, **Onshore DC Converter**,~~ **OTSDUW Plant and Apparatus** or **Onshore Power Park Module** should be that which results from the supply of maximum lagging reactive current whilst ensuring the current remains within design operating limits. An example of the capability is shown by the line DE in figures ECC.A.7.2.2b and ECC.A.7.2.2c. For **Onshore** **Connection** ~~**Grid Entry**~~ **Point** voltages (~~or **User System Entry Point** voltages if **Embedded**~~ or **Interface Point** voltages) above 105%, the leading **Reactive Power** capability of the ~~**Onshore Non-Synchronous Generating Unit**, **Onshore DC Converter**~~, **OTSDUW Plant and Apparatus** or **Onshore Power Park Module** should be that which results from the supply of maximum leading reactive current whilst ensuring the current remains within design operating limits. An example of the capability is shown by the line AH in figures ECC.A.7.2.2b and ECC.A.7.2.2c. Should the **Reactive Power** output of the ~~**Onshore Non-Synchronous Generating Unit**, **Onshore DC Converter**,~~ **OTSDUW Plant and Apparatus** or **Onshore Power Park Module** reach its maximum lagging limit at a~~n~~ ~~**Onshore Grid Entry**~~ **Connection** **Point** voltage (~~or **Onshore User System Entry Point** voltage if **Embedded**~~ or **Interface Point** in the case of **OTSDUW Plant and Apparatus**) below 95%, the ~~**Onshore Non-Synchronous Generating Unit**, **Onshore DC Converter** or~~ **Onshore Power Park Module** shall maintain maximum lagging reactive current output for further voltage decreases. Should the **Reactive Power** output of the ~~**Onshore Non-Synchronous Generating Unit**, **Onshore DC Converter**,~~ **OTSDUW Plant and Apparatus** or **Onshore Power Park Module** reach its maximum leading limit at a **Onshore** ~~**Grid Entry**~~ **Connection** **Point** voltage (~~or **User System Entry Point** voltage if **Embedded**~~ or **Interface Point** voltage in the case of an **OTSDUW Plant and Apparatus**) above 105%, the ~~**Onshore Non-Synchronous Generating Unit**, **Onshore DC Converter**,~~ **OTSDUW Plant and Apparatus** or **Onshore Power Park Module** shall maintain maximum leading reactive current output for further voltage increases.

ECC.A.7.2.2.8 All **OTSDUW Plant and Apparatus** must be capable of enabling **Users** undertaking **OTSDUW** to comply with an instruction received from **NGET** relating to a variation of the **Setpoint Voltage** at the **Interface Point** within 2 minutes of such instruction being received.

ECC.A.7.2.2.9 For **OTSDUW Plant and Apparatus** connected to a **Network Operator's System** where the **Network Operator** has confirmed to **NGET** that its **System** is restricted in accordance with ECC.A.7.2.1, clause ECC.A.7.2.2.8 will not apply unless **NGET** can reasonably demonstrate that the magnitude of the available change in **Reactive Power** has a significant effect on voltage levels on the **Onshore National Electricity Transmission System**.

ECC.A.7.2.3 Transient Voltage Control

ECC.A.7.2.3.1 For an on-load step change in **Connection Point** ~~**Onshore Grid Entry Point** or **Onshore User System Entry Point**~~ voltage, or in the case of **OTSDUW Plant and Apparatus** an on-load step change in **Transmission Interface Point** voltage, the continuously acting automatic control system shall respond according to the following minimum criteria:

(i) the **Reactive Power** output response of the ~~**Onshore Non-Synchronous Generating Unit**, **Onshore DC Converter**,~~ **OTSDUW Plant and Apparatus** or **Onshore Power Park Module** shall commence within 0.2 seconds of the application of the step. It shall progress linearly although variations from a linear characteristic shall be acceptable provided that the MVAr seconds delivered at any time up to 1 second are at least those that would result from the response shown in figure ECC.A.7.2.3.1a.

(ii) the response shall be such that 90% of the change in the **Reactive Power** output of the ~~**Onshore Non-Synchronous Generating Unit**, **Onshore DC Converter**,~~ **OTSDUW Plant and Apparatus** or **Onshore Power Park Module**, will be achieved within

- 2 seconds, where the step is sufficiently large to require a change in the steady state **Reactive Power** output from its maximum leading value to its maximum lagging value or vice versa and

- 1 second where the step is sufficiently large to require a change in the steady state **Reactive Power** output from zero to its maximum leading value or maximum lagging value as required by ECC.6.3.2 (or, if appropriate ECC.A.7.2.2.6 or ECC.A.7.2.2.7);

(iii) the magnitude of the **Reactive Power** output response produced within 1 second shall vary linearly in proportion to the magnitude of the step change.

(iv) within ~~2~~ 5 seconds from achieving 90% of the response as defined in ECC.A.7.2.3.1 (ii), the peak to peak magnitude of any oscillations shall be less than 5% of the change in steady state maximum **Reactive Power**.

(v) following the transient response, the conditions of ECC.A.7.2.2 apply.

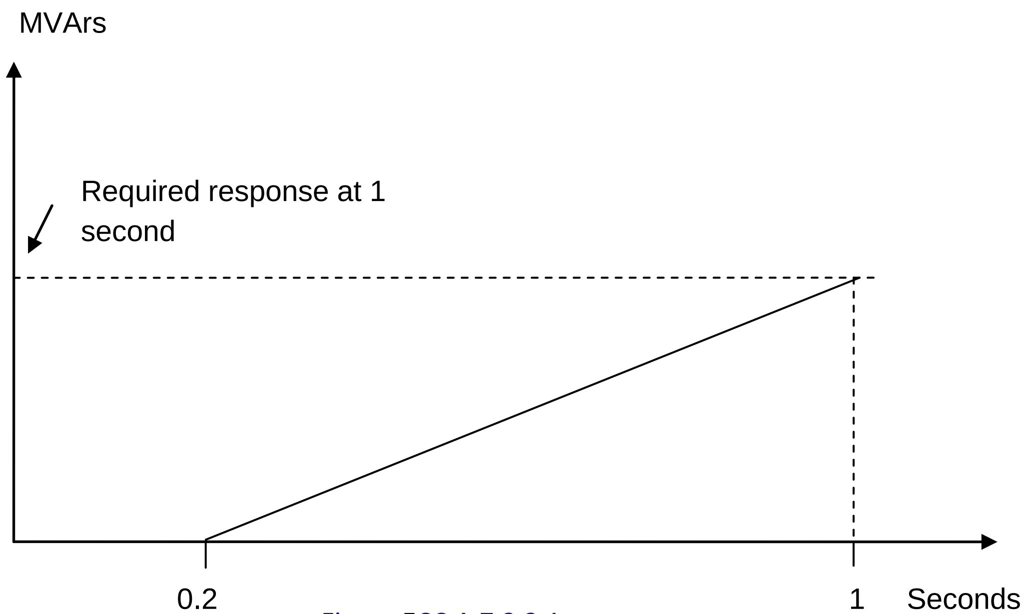



Figure ECC.A.7.2.3.1a

ECC.A.7.2.3.2 An ~~**Onshore Non-Synchronous Generating Unit, Onshore DC Converter,**~~ **OTSDUW Plant and Apparatus** or **Onshore Power Park Modules** shall be capable of

(a) changing its **Reactive Power** output from its maximum lagging value to its maximum leading value, or vice versa, then reverting back to the initial level of **Reactive Power** output once every 15 seconds for at least 5 times within any 5 minute period; and

(b) changing its **Reactive Power** output from zero to its maximum leading value then reverting back to zero **Reactive Power** output at least 25 times within any 24 hour period and from zero to its maximum lagging value then reverting back to zero **Reactive Power** output at least 25 times within any 24 hour period. Any subsequent restriction on reactive capability shall be notified to **NGET** in accordance with BC2.5.3.2, and BC2.6.1.

In all cases, the response shall be in accordance to ECC.A.7.2.3.1 where the change in **Reactive Power** output is in response to an on-load step change in **Onshore Connection** ~~**Grid Entry Point** or **Onshore User System Entry**~~ **Point** voltage, or in the case of **OTSDUW Plant and Apparatus** an on-load step change in **Transmission Interface Point** voltage.

ECC.A.7.2.4 Power Oscillation Damping

ECC.A.7.2.4.1 The requirement for the continuously acting voltage control system to be fitted with a **Power System Stabiliser (PSS)** shall be specified in the **Bilateral Agreement** if, in **NGET's** view, this is required for system reasons. However if a **Power System Stabiliser** is included in the voltage control system its settings and performance shall be agreed with **NGET** and commissioned in accordance with BC2.11.2. To allow assessment of the performance before on-load commissioning the **Generator** will provide to **NGET** a report covering the areas specified in CP.A.3.2.2.

ECC.A.7.2.5 Overall Voltage Control System Characteristics

ECC.A.7.2.5.1 The continuously acting automatic voltage control system is required to respond to minor variations, steps, gradual changes or major variations in **Onshore Grid Entry Point** voltage (or **Onshore User System Entry Point** voltage if **Embedded** or **Interface Point** voltage in the case of **OTSDUW Plant and Apparatus**).

ECC.A.7.2.5.2 The overall voltage control system shall include elements that limit the bandwidth of the output signal. The bandwidth limiting must be consistent with the speed of response requirements and ensure that the highest frequency of response cannot excite torsional oscillations on other plant connected to the network. A bandwidth of 0-5Hz would be judged to be acceptable for this application. All other control systems employed within the ~~**Onshore Non-Synchronous Generating Unit**, **Onshore DC Converter**,~~ **OTSDUW Plant and Apparatus** or **Onshore Power Park Module** should also meet this requirement

ECC.A.7.2.5.3 The response of the voltage control system (including the **Power System Stabiliser** if employed) shall be demonstrated by testing in accordance with OC5A.A.3.

ECC.A.7.3 **Reactive Power** Control

ECC.A.7.3.1 As defined in ECC.6.3.8.3.4, **Reactive Power** control mode of operation is not required in respect of **Onshore Power Park Modules** or **OTSDUW Plant and Apparatus** unless otherwise recorded in the **Bilateral Agreement**. However where there is a requirement for **Reactive Power** control mode of operation, the following requirements shall apply.

ECC.A.7.3.2 The **Onshore Power Park Module** or **OTSDUW Plant and Apparatus** shall be capable of setting the **Reactive Power** setpoint anywhere in the **Reactive Power** range as specified in ECC.6.3.2.6 with setting steps no greater than 5 MVAr or 5% (whichever is smaller) of full **Reactive Power**, controlling the reactive power at the **Connection Point** to an accuracy within plus or minus 5MVAr or plus or minus 5% (whichever is smaller) of the full **Reactive Power**.

ECC.A.7.3.3 Any additional requirements for **Reactive Power** control mode of operation shall be specified in the **Bilateral Agreement**.

ECC.A.7.4 <u>**Power Factor** Control</u>

ECC.A.7.4.1 As defined in ECC.6.3.8.4.3, **Power Factor** control mode of operation is not required in respect of **Onshore Power Park Modules** or **OTSDUW Plant and Apparatus** unless otherwise recorded in the **Bilateral Agreement**. However where there is a requirement for **Power Factor** control mode of operation, the following requirements shall apply.

ECC.A.7.4.2 The Onshore **Power Park Module** or **OTSDUW Plant and Apparatus** shall be capable of controlling the **Power Factor** at the **Connection Point** within the required **Reactive Power** range as specified in ECC.6.3.2.2.1 and ECC.6.3.2.4 ~~with~~ to a specified target **Power Factor** ~~in steps no greater than 0.01~~. **NGET** shall specify the target **Power Factor** value (which shall be achieved within 0.01 of the set **Power Factor**), its tolerance and the period of time to achieve the target **Power Factor** following a sudden change of **Active Power** output. The tolerance of the target **Power Factor** shall be expressed through the tolerance of its corresponding **Reactive Power**. This **Reactive Power** tolerance shall be expressed by either an absolute value or by a percentage of the maximum **Reactive Power** of the **Onshore Power Park Module** or **OTSDUW Plant and Apparatus**. The details of these requirements being pursuant to the terms of the **Bilateral Agreement**.

ECC.A.7.4.3 Any additional requirements for **Power Factor** control mode of operation shall be specified in the **Bilateral Agreement**.

## APPENDIX 8 - PERFORMANCE REQUIREMENTS FOR CONTINUOUSLY ACTING AUTOMATIC VOLTAGE CONTROL SYSTEMS FOR CONFIGURATION 2 AC CONNECTED OFFSHORE POWER PARK MODULES

ECC.A.8.1 Scope

ECC.A.8.1.1 This Appendix sets out the performance requirements of continuously acting automatic voltage control systems for **Configuration 2 AC connected Offshore Power Park Modules** that must be complied with by the **User**. This Appendix does not limit any site specific requirements that may be included in a **Bilateral Agreement** where in **NGET's** reasonable opinion these facilities are necessary for system reasons.

ECC.A.8.1.2 Proposals by **Generators** to make a change to the voltage control systems are required to be notified to **NGET** under the **Planning Code** (PC.A.1.2(b) and (c)) as soon as the **Generator** anticipates making the change. The change may require a revision to the **Bilateral Agreement**.

ECC.A.8.2 Requirements

ECC.A.8.2.1 **NGET** requires that the continuously acting automatic voltage control system for the **Configuration 2 AC connected Offshore Power Park Module** shall meet the following functional performance specification.

ECC.A.8.2.2 Steady State Voltage Control

ECC.A.8.2.2.1 The **Configuration 2 AC connected Offshore Power Park Module** shall provide continuous steady state control of the voltage at the **Offshore Connection Point** with a **Setpoint Voltage** and **Slope** characteristic as illustrated in Figure ECC.A.8.2.2a.

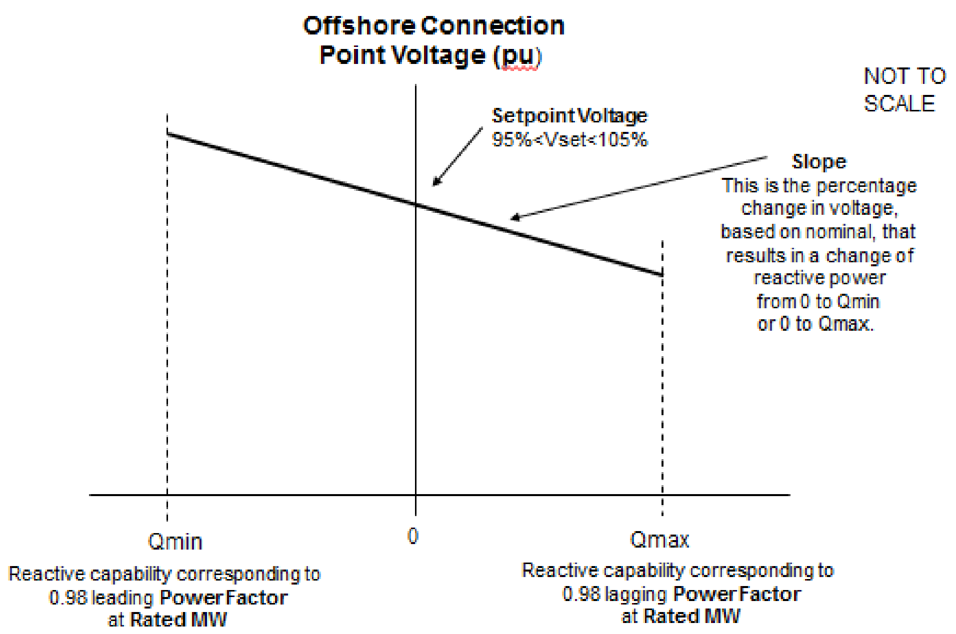



Figure ECC.A.8.2.2a

ECC.A.8.2.2.2 The continuously acting automatic control system shall be capable of operating to a **Setpoint Voltage** between 95% and 105% with a resolution of 0.25% of the nominal voltage. For the avoidance of doubt values of 95%, 95.25%, 95.5% … may be specified, but not intermediate values. The initial **Setpoint Voltage** will be 100%. The tolerance within which this **Setpoint Voltage** shall be achieved is specified in BC2.A.2.6. For the avoidance of doubt, with a tolerance of 0.25% and a Setpoint Voltage of 100%, the achieved value shall be between 99.75% and 100.25%. **NGET** may request the **Generator** to implement an alternative **Setpoint Voltage** within the range of 95% to 105%.

ECC.A.8.2.2.3 The **Slope** characteristic of the continuously acting automatic control system shall be adjustable over the range 2% to 7% (with a resolution of 0.5%). For the avoidance of doubt values of 2%, 2.5%, 3% may be specified, but not intermediate values. The initial **Slope** setting will be 4%. The tolerance within which this **Slope** shall be achieved is specified in BC2.A.2.6. For the avoidance of doubt, with a tolerance of 0.5% and a **Slope** setting of 4%, the achieved value shall be between 3.5% and 4.5%. **NGET** may request the **Generator** to implement an alternative slope setting within the range of 2% to 7%.

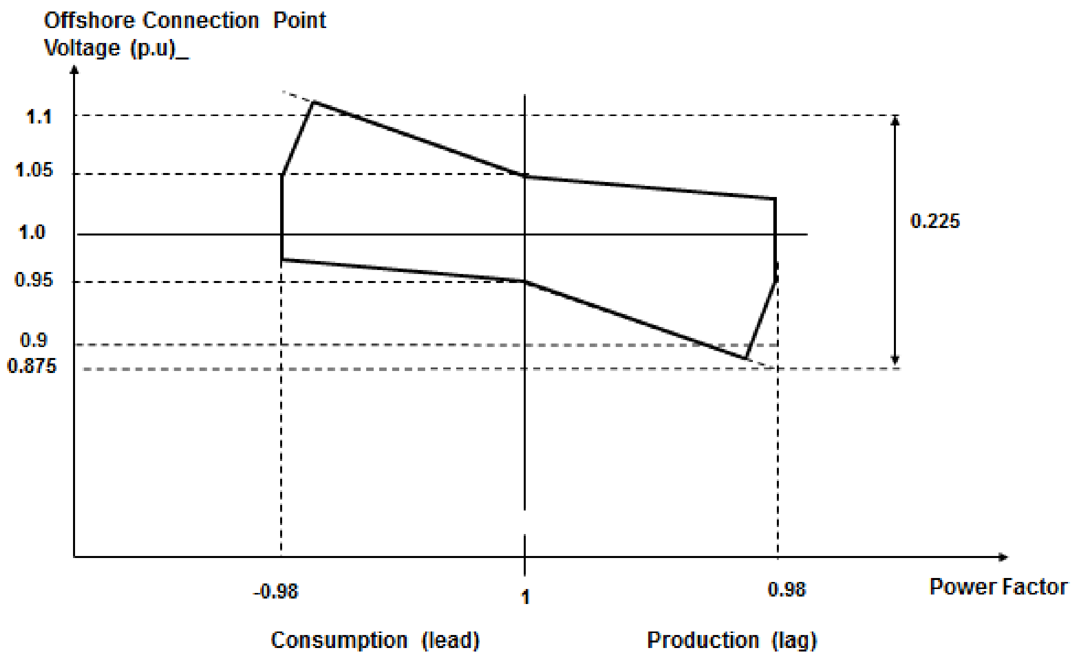



Figure ECC.A.8.2.2b

ECC.A.8.2.2.4 Figure ECC.A.8.2.2b shows the required envelope of operation for **Configuration 2 AC connected Offshore Power Park Modules.** The enclosed area within points ABCDEFGH is the required capability range within which the **Slope** and **Setpoint Voltage** can be changed.

ECC.A.8.2.2.5 Should the operating point of the **Configuration 2 AC connected Offshore Power Park** deviate so that it is no longer a point on the operating characteristic (Figure ECC.A.8.2.2a) defined by the target **Setpoint Voltage** and **Slope**, the continuously acting automatic voltage control system shall act progressively to return the value to a point on the required characteristic within 5 seconds.

ECC.A.8.2.2.6 Should the **Reactive Power** output of the **Configuration 2 AC connected Offshore Power Park Module** reach its maximum lagging limit at an **Offshore Connection Point** voltage above 95%, the **Configuration 2 AC connected Offshore Power Park Module** shall maintain maximum lagging **Reactive Power** output for voltage reductions down to 95%. This requirement is indicated by the line EF in figure ECC.A.8.2.2b. Should the **Reactive Power** output of the **Configuration 2 AC connected Offshore Power Park Module** reach its maximum leading limit at the **Offshore Connection Point** voltage below 105%, the **Configuration 2 AC connected Offshore Power Park Module** shall maintain maximum leading **Reactive Power** output for voltage increases up to 105%. This requirement is indicated by the line AB in figures ECC.A.7.2.2b.

ECC.A.8.2.2.7 For **Offshore Connection Point** voltages below 95%, the lagging **Reactive Power** capability of the **Configuration 2 AC connected Offshore Power Park Module** should be that which results from the supply of maximum lagging reactive current whilst ensuring the current remains within design operating limits. An example of the capability is shown by the line DE in figures ECC.A.8.2.2b. For **Offshore Connection Point** voltages above 105%, the leading **Reactive Power** capability of the **Configuration 2 AC connected Offshore Power Park Module** should be that which results from the supply of maximum leading reactive current whilst ensuring the current remains within design operating limits. An example of the capability is shown by the line AH in figures ECC.A.8.2.2b. Should the **Reactive Power** output of the **Configuration 2 AC connected Offshore Power Park Module** reach its maximum lagging limit at an Offshore **Connection Point** voltage below 95%, the **Configuration 2 AC connected Offshore Power Park Module** shall maintain maximum lagging reactive current output for further voltage decreases. Should the **Reactive Power** output of the **Configuration 2 AC connected Offshore Power Park Module** reach its maximum leading limit at an **Offshore Connection Point** voltage above 105%, the **Configuration 2 AC connected Offshore Power Park Module** shall maintain maximum leading reactive current output for further voltage increases.

ECC.A.8.2.3 <u>Transient Voltage Control</u>

ECC.A.8.2.3.1 For an on-load step change in **Offshore Connection Point** voltage an on-load step change in **Offshore Connection Point** voltage, the continuously acting automatic control system shall respond according to the following minimum criteria:

(i) the **Reactive Power** output response of the **Configuration 2 AC connected Offshore Power Park Module** shall commence within 0.2 seconds of the application of the step. It shall progress linearly although variations from a linear characteristic shall be acceptable provided that the MVAr seconds delivered at any time up to 1 second are at least those that would result from the response shown in figure ECC.A.8.2.3.1a.

(ii) the response shall be such that 90% of the change in the **Reactive Power** output of the **Configuration 2 AC connected Offshore Power Park Module** will be achieved within

– 2 seconds, where the step is sufficiently large to require a change in the steady state **Reactive Power** output from its maximum leading value to its maximum lagging value or vice versa and

– 1 second where the step is sufficiently large to require a change in the steady state **Reactive Power** output from zero to its maximum leading value or maximum lagging value as required by ECC.6.3.2 (or, if appropriate ECC.A.8.2.2.6 or ECC.A.8.2.2.7);

(iii) the magnitude of the **Reactive Power** output response produced within 1 second shall vary linearly in proportion to the magnitude of the step change.

(iv) within 5 seconds from achieving 90% of the response as defined in ECC.A.8.2.3.1 (ii), the peak to peak magnitude of any oscillations shall be less than 5% of the change in steady state maximum **Reactive Power**.

(v) following the transient response, the conditions of ECC.A.8.2.2 apply.

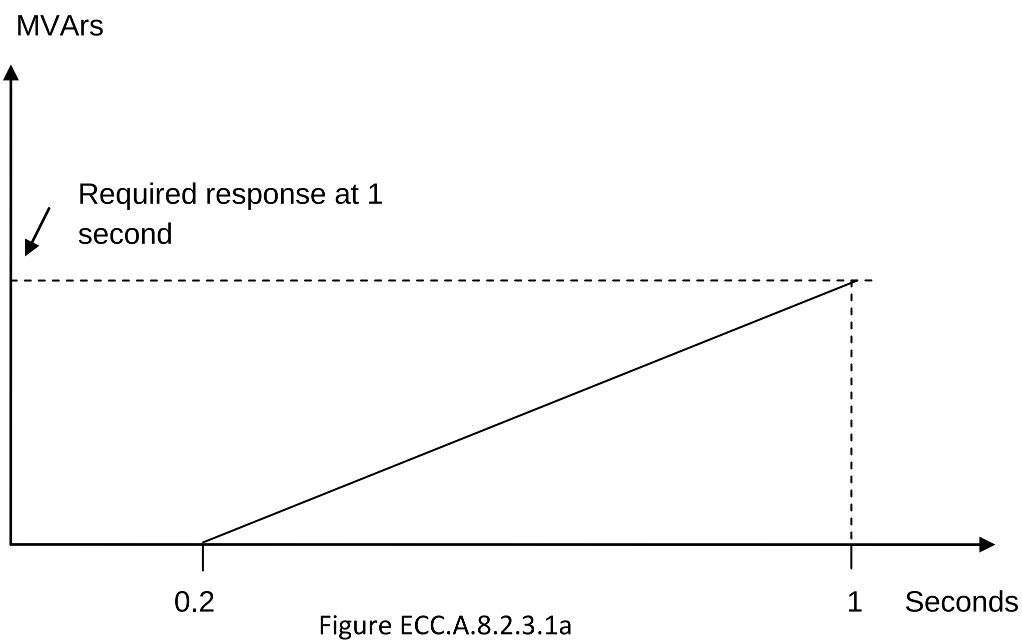



Figure ECC.A.8.2.3.1a

ECC.A.8.2.3.2 **Configuration 2 AC connected Offshore Power Park Module** shall be capable of

(a) changing its **Reactive Power** output from its maximum lagging value to its maximum leading value, or vice versa, then reverting back to the initial level of **Reactive Power** output once every 15 seconds for at least 5 times within any 5 minute period; and

(b) changing its **Reactive Power** output from zero to its maximum leading value then reverting back to zero **Reactive Power** output at least 25 times within any 24 hour period and from zero to its maximum lagging value then reverting back to zero **Reactive Power** output at least 25 times within any 24 hour period. Any subsequent restriction on reactive capability shall be notified to **NGET** in accordance with BC2.5.3.2, and BC2.6.1.

In all cases, the response shall be in accordance to ECC.A.8.2.3.1 where the change in **Reactive Power** output is in response to an on-load step change in **Offshore Connection Point** voltage.

ECC.A.8.2.4 Power Oscillation Damping

ECC.A.8.2.4.1 The requirement for the continuously acting voltage control system to be fitted with a **Power System Stabiliser (PSS)** shall be specified in the **Bilateral Agreement** if, in **NGET's** view, this is required for system reasons. However if a **Power System Stabiliser** is included in the voltage control system its settings and performance shall be agreed with **NGET** and commissioned in accordance with BC2.11.2. To allow assessment of the performance before on-load commissioning the **Generator** will provide to **NGET** a report covering the areas specified in CP.A.3.2.2.

ECC.A.8.2.5 Overall Voltage Control System Characteristics

ECC.A.8.2.5.1 The continuously acting automatic voltage control system is required to respond to minor variations, steps, gradual changes or major variations in **Offshore Connection Point** voltage.

ECC.A.8.2.5.2 The overall voltage control system shall include elements that limit the bandwidth of the output signal. The bandwidth limiting must be consistent with the speed of response requirements and ensure that the highest frequency of response cannot excite torsional oscillations on other plant connected to the network. A bandwidth of 0-5Hz would be judged to be acceptable for this application. All other control systems employed within the **Configuration 2 AC connected Offshore Power Park Module** should also meet this requirement

ECC.A.8.2.5.3 The response of the voltage control system (including the **Power System Stabiliser** if employed) shall be demonstrated by testing in accordance with OC5A.A.3.

ECC.A.8.3 **Reactive Power** Control

ECC.A.8.3.1 **Reactive Power** control mode of operation is not required in respect of **Configuration 2 AC connected Offshore Power Park Module** unless otherwise recorded in the **Bilateral Agreement**. However where there is a requirement for **Reactive Power** control mode of operation, the following requirements shall apply.

ECC.A.8.3.2 **Configuration 2 AC connected Offshore Power Park Module** shall be capable of setting the **Reactive Power** setpoint anywhere in the **Reactive Power** range as specified in ECC.6.3.2.8.2 with setting steps no greater than 5 MVAr or 5% (whichever is smaller) of full **Reactive Power**, controlling the reactive power at the **Offshore Connection Point** to an accuracy within plus or minus 5MVAr or plus or minus 5% (whichever is smaller) of the full **Reactive Power**.

ECC.A.8.3.3 Any additional requirements for **Reactive Power** control mode of operation shall be specified in the **Bilateral Agreement**.

ECC.A.8.4 **Power Factor** Control

ECC.A.8.4.1 **Power Factor** control mode of operation is not required in respect of **Configuration 2 AC connected Offshore Power Park Module** unless otherwise recorded in the **Bilateral Agreement**. However where there is a requirement for **Power Factor** control mode of operation, the following requirements shall apply.

ECC.A.8.4.2 The **Configuration 2 AC connected Offshore Power Park Module** shall be capable of controlling the **Power Factor** at the **Offshore Connection Point** within the required **Reactive Power** range as specified in ECC.6.3.2.8.2with a target **Power Factor**. **NGET** shall specify the target **Power Factor** (which shall be achieved to within 0.01 of the set **Power Factor**), its tolerance and the period of time to achieve the target **Power Factor** following a sudden change of **Active Power** output. The tolerance of the target **Power Factor** shall be expressed through the tolerance of its corresponding **Reactive Power**. This **Reactive Power** tolerance shall be expressed by either an absolute value or by a percentage of the maximum **Reactive Power** of the **Configuration 2 AC connected Offshore Power Park Module.** The details of these requirements being pursuant to the terms of the **Bilateral Agreement**.

ECC.A.8.4.3 Any additional requirements for **Power Factor** control mode of operation shall be specified in the **Bilateral Agreement**.

…………

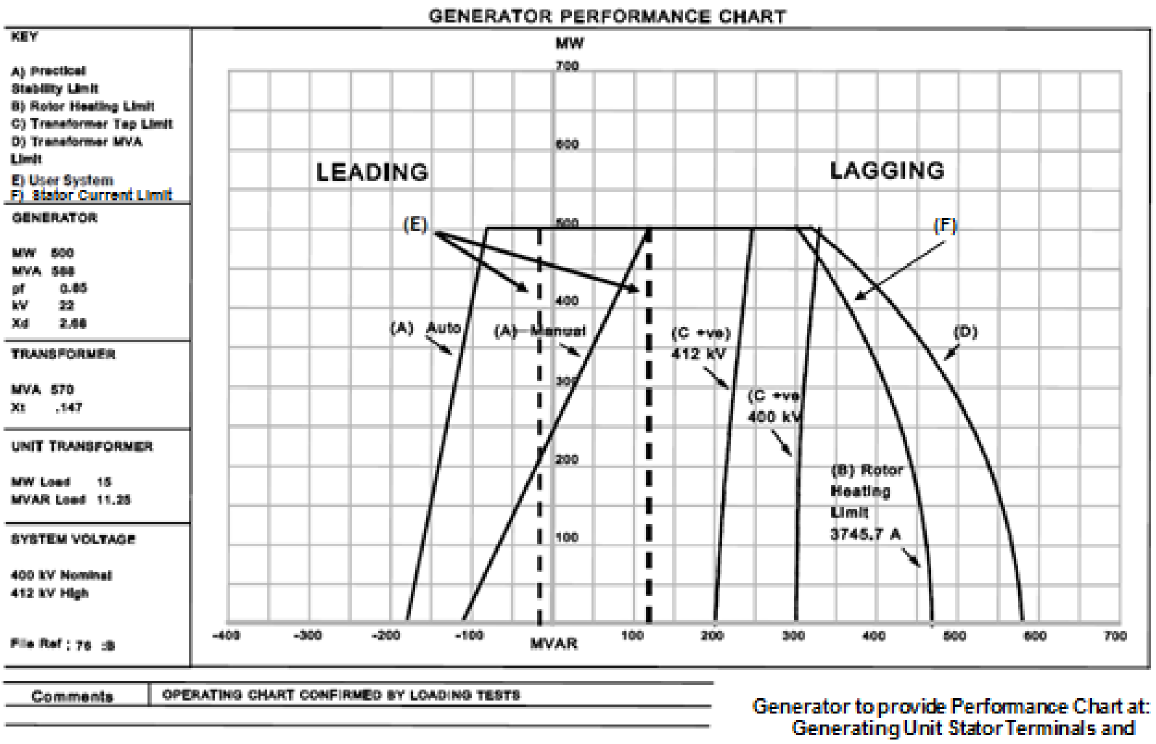
**OPERATING CONDITIONS 2 (OC2)**

OC2.4.2 DATA REQUIREMENTS

OC2.4.2.1(g) The **Generator Performance Chart** must be as described below and demonstrate the limitation on reactive capability of the **System** voltage at 3% above nominal. It must also include any limitations on output due to the prime mover (both maximum and minimum), **Generating Unit** step up transformer or **User System**.

(i) For a **Synchronous Generating Unit** on a **Generating Unit** specific basis at the **Generating Unit** Stator Terminals. It must include details of the Generating Unit transformer parameters. In addition, **Generators** in respect of **Synchronous Power Generating Modules** should also provide a performance chart at the **Connection Point**, in the same format as required under OC2 - Appendix 1.

**OC2 – APPENDIX 1 – PERFORMANCE CHART**




Generator to provide Performance Chart at: Generating Unit Stator Terminals and the Connection Point

## DATA REGISTRATION CODE

DRC Schedule 1 – Page 13

| DATA DESCRIPTION | UNITS | DATA to **RTL** | | DATA CAT. | **GENERATING UNIT** (OR CCGT MODULE, AS THE CASE MAY BE) | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | CUSC Contract | CUSC App. Form | | G1 | G2 | G3 | G4 | G5 | G6 | STN |
| Rated MVA *(PC.A.3.3.1)* | MVA | □ | ■ | **SPD+** | | | | | | | |
| Rated MW *(PC.A.3.3.1)* | MW | □ | ■ | **SPD+** | | | | | | | |
| Rated terminal voltage *(PC.A.5.3.2.(a) & PC.A.5.4.2 (b))* | kV | □ | | **DPD I** | | | | | | | |
| *Performance Chart at **Onshore Synchronous Generating Unit** stator terminals and at the **Connection Point** *(PC.A.3.2.2(f)(i))* | | | | **SPD** | (see **OC2** for specification) | | | | | | |
| * Performance Chart of the **Offshore Synchronous Generating Unit** at the **Offshore Grid Entry Point** *(PC.A.3.2.2(f)(ii))* | kV<br>kV | □<br>□ | | **DPD I**<br>**DPD I** | | | | | | | |
| * Maximum terminal voltage setpoint*(PC.A.5.3.2.(a) & PC.A.5.4.2 (b))* | | | | | | | | | | | |
| * Terminal voltage setpoint step resolution – if not continuous *(PC.A.5.3.2.(a) & PC.A.5.4.2 (b))* | | | | | | | | | | | |

## VOLTAGE / REACTIVE – GRID CODE LEGAL TEXT ISSUES TABLE

| No | Article | Issue | Comments |
|---|---|---|---|
| 1 | Art 16 (2) | Voltage Range | Use existing GB text with slight modifications. The advantage of this approach is that it will pick up RfG, DCC and HVDC and also cover the gaps left by RfG for Type A, B and C Generators whilst also retaining consistency. |
| 2 | Art 20 (2)(a) | Type PPM's – Reactive Capability | Discussion Point – Minimum value of 0.95PF lead to 0.95PF lag specified at the connection point unless otherwise specified by NGET or Network Operator. The Control System shall contribute to voltage control, Reactive Power control or Power Factor control as specified in the Connection Agreement (worded for maximum flexibility) |
| 3 | Art 18 (2)(a)<br>Art 21 (3)(a) | Reactive Capability at Connection Point | Included as part of RfG drafting – It is unlikely that the network would be owned by another party (ie not a Network Operator but possible and has been included within the scope of the drafting) |
| 4 | Art 18(2)(b)&(c) | Mix of terms – Generating Unit and Alternator | For GB drafting the term Generating Unit has been used. RfG uses Alternator but it is assumed that Alternator and Generating Unit mean the same thing. The GB definition of Generating Unit has been updated to reflect this. |
| 5 | N/A | CC.6.3.2(a)(i)&(ii) | Now the Reactive Capability is defined at the Connection Point it is unclear if this requirement is necessary in a post European world |
| 6 | N/A | CC.6.3.2(c) – In Scotland the Reactive capability for a Power Park Module is specified at the HV Side of the Transformer. In GB it is at the Connection Point | Under the RfG drafting it is proposed to remove this requirement so the requirement is consistent across the whole of GB |

| | | | |
|---|---|---|---|
| 7 | Art 25(5) | Reactive Capability – Offshore Power Park Modules | Under the GB Code, the reactive capability of Offshore Synchronous Power Generating Modules is defined whereas they are not in RfG. The same principles of RfG as applied to Offshore PPM's has also been applied to Offshore Synchronous Generating Units. |
| 8 | Art 25(5) | Reactive Capability – Offshore Power Park Modules | Tolerance of ±5% has been included in text. RfG does not specifically address this but Art 21((d)(v) does permit this tolerance for onshore Reactive Power control so the same requirement is assumed to apply offshore. |
| 9 | CC.6.3.6 | Real Time Frequency Provision – for HVDC Converters which form part of a OTSDUW Plant and Apparatus | Included in this section. It will also need to be included in the HVDC section of the code when updated. |
| 10 | Definition | Generator | As part of the legal drafting the term Generator has been used instead of Power Generating Facility Owner. Generator is considered to be the more eloquent definition |
| 11 | Article 19(2)(b)(iv) | Stator current Limiter | The text in ECC.A.6.2.8 has been updated to i) remove "where it exists" as RfG stipulates a Stator Current Limiter. |
| 12 | Article 25 | Treatment of Offshore Power Park Modules | AC Connected Configuration 1 Offshore Power Park Modules have to satisfy the requirement of zero transfer of reactive power at the Offshore Grid Entry Point which effectively makes them unable to contribute to voltage control at the Interface Point |
| 13 | Article 21(d)(v) and (vi) | Reactive Power Control and Power Factor Control | Drafting is limited only to onshore Power Park Modules. Drafting also includes OTSDUW Plant and Apparatus to reflect the Offshore Transmission Regime. |

Insert Heading

Use this column in a Q&A style for explanations, in order to preserve the flow of the main text.

**Draft G99 text applicable to Voltage and Control**

**NOTE:- THIS SECTION HAS BEEN PROVIDED IN GOOD FAITH FOR INFORMATION ONLY IN ORDER TO GIVE AN INDICATION OF THE STRUCTURE OF SECTION 9 OF G99. IT IS NOT PART OF THIS CONSULTATION AND COMMENTS ARE NOT REQUESTED ON THE TECHNICAL CONTENT OF THIS TEXT.**

Purple text = from G59

Brown/Orange text = from RfG (June 2015)

Green text = from other EU documents referenced by RfG

Blue text = from Distribution Code

Black text = Changes/ additional words

Red text = Words that may/ will need changing

A complete review of the Glossary and Definitions will be required when the full suite of European Codes has been implemented. The current assumption is to use GB definitions where appropriate with use of European definitions where required. A consistency check will also be required between the Glossary and Definitions in the Grid Code and those in the Distribution Code.

[9.8 **Voltage Limits and Control**

9.8.1 Where **a Power Generating Module** is remote from a network voltage control point it may be required to withstand voltages outside the normal statutory limits. In these circumstances, the **DNO** should agree with the **Power Generating Facility Owner** the declared voltage and voltage range at the **Connection Point**. Immunity of the **Power Generating Module** to voltage changes of ± 10% of the declared voltage is recommended, subject to design appraisal of individual installations.

9.8.2 The connection of a **Power Generating Module** to the **Distribution Network** shall be designed in such a way that operation of the **Power Generating Module** does not adversely affect the voltage profile of and voltage control employed on the **Distribution Network**. ETR 126 provides **DNOs** with guidance on active management solutions to overcome voltage control limitations. Information on the voltage regulation and control arrangements will be made available by the **DNO** if requested by the **User.**

9.8.3 When supplying **Rated MW** all Type B **Power Generating Modules** must be capable of continuous operation at any points between the limits of 0.95 Power Factor lagging and 0.95 Power Factor leading at the **Connection Point** unless otherwise specified by the **DNO** in the **Connection Agreement.**

9.8.4 At Active Power output levels other than **Rated MW**, all alternators within a Type B **Synchronous Power Generating Modules** must be capable of continuous operation at any point between the **Reactive Power** capability limits identified on the **Generator Performance Chart** unless otherwise agreed with the **DNO**.

9.8.5 At Active Power output levels other than **Rated MW**, all Type B **Power Park Modules** must be capable of continuous operation at any point between the **Reactive Power** capability limits identified on the P-Q operating chart unless otherwise agreed with the **DNO**.

9.8.6 Each Type B **Synchronous Power Generating Module** shall be equipped with a permanent automatic excitation system that can provide constant alternator terminal voltage at a selectable setpoint without instability over the entire operating range of the Type B Synchronous **Power Generating Module**.

9.8.7 The **DNO** will specify in the **Connection Agreement** if the control system of the Type B **Synchronous Power Generating Module** or **Power Park Module** shall contribute to voltage control or Reactive Power control or Power Factor control at the **Connection Point** (or other defined busbar). The performance requirements of the control system including droop (where applicable) shall be specified in the **Connection Agreement**.

9.8.8 The final responsibility for control of **Distribution Network** voltage does however remain with the **DNO**.

Brown/Orange text = from RfG (June 2015)
Green text = from other EU documents referenced by RfG
Blue text = from Distribution Code
Black text = Changes/ additional words
Red text = Words that may/ will need changing

**Draft G99 text for Section 9 Network Connection Design and Operation**

**NOTE:- THIS SECTION HAS BEEN PROVIDED IN GOOD FAITH FOR INFORMATION ONLY IN ORDER TO GIVE AN INDICATION OF THE STRUCTURE OF SECTION 9 OF G99. IT IS NOT PART OF THIS CONSULTATION AND COMMENTS ARE NOT REQUESTED ON THE TECHNICAL CONTENT OF THIS TEXT.**

Purple text = from G59
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Blue text = from Distribution Code or Grid Code
Black text = Changes/ additional words
Red text = Words that may/ will need changing

# 9 NETWORK CONNECTION DESIGN AND OPERATION

## 9.1 General Criteria

9.1.1 As outlined in Section 5, **DNO**s have to meet certain statutory and **Distribution Licence** obligations when designing and operating their **Distribution Networks**. These obligations will influence the options for connecting **Power Generating Modules**.

9.1.2 The **DNO** has a duty to develop and maintain an efficient, secure and co-ordinated **Network** of electricity supply that is both economical and safe.

9.1.3 **This Section** sets out current principles and standards to be applied in the design of the **DNO's Distribution Network** and any **User** connections to that **Network.** Each scheme for reinforcement or modification of the **DNO's Distribution Network** is individually designed in the light of economic and technical features associated with the particular **System** limitations under consideration.

9.1.4 Nothing in this section is intended to inhibit design innovation**.** This Section is, therefore, based upon the performance requirements of the **DNO's Distribution Network** necessary to meet the above criteria.

9.1.5 The technical and design criteria to be applied in the design of the **Distribution Network** and **Power Generating Module** connection are detailed in this document. The criteria are based upon the performance requirements of the **Distribution Network** necessary to meet the above obligations. These standards may be subject to revision from time to time in accordance with the provision of the **Distribution Licence**.

9.1. The **Distribution Network**, and any **Power Generating Module**

6 connection to that network, shall be designed,

a. to comply with the obligations (to include security, frequency and voltage; voltage disturbances and harmonic distortion; auto reclosing and single phase protection operation).

b. according to design principles in relation to **Distribution Network**'s plant and equipment, earthing, voltage regulation and control, and protection as outlined in this section, subject to any modification to which the **DNO** may reasonably consent.

9.1.7 **Power Generating Modules** should meet a set of technical requirements in relation to its performance with respect to frequency and voltage, control capabilities, protection coordination requirements, phase voltage unbalance requirements, neutral earthing provisions, islanding and **black start capability**. These requirements are listed in this section.

9.1.8 There are additional performance requirements that are specified in the **Grid Code** for all embedded **Power Generating Facilities** comprising **Power Generating Modules** greater than 50 MW. The requirements for Type C **Power Generating Modules** are referenced in section 9.16, and are all listed in ECC3.3 to ECC3.5 of the **Grid Code**. For Embedded Type D **Power Generating Modules** the **Grid Code** generally applies in full.

9.1.9 In accordance with Condition 14 of its **Distribution Licence** the **DNO**, on the request of a **User,** will prepare a statement showing present and future circuit capacity, forecast power flows and loading on the part or parts of the **DNO's Distribution Network** specified in the request and **Fault Levels** at each distribution node covered by the request and containing:

a) such further information as shall be reasonably necessary to enable such person to identify and evaluate the opportunities available when connecting to and making use of the part or parts of the licensee's distribution network specified in the request ;and

b) if so requested, a commentary prepared by the licensee indicating the licensee's views as to the suitability of the part or parts of the licensee's distribution network specified in the request for new connections and the distribution of further quantities of electricity..

The **Distribution Licence** sets out conditions on the time scales and charges associated with providing such a statement

9.1.10 In accordance with Condition 25 of its Distribution Licence the **DNO** will prepare on the request of the **Authority** a statement, also known as the Long Term Development Statement. The form and content of this statement will be specified by the **Authority** and will cover future years on a rolling basis. This statement gives information to assist any person who contemplates entering into distribution arrangements with the **DNO** to identify and evaluate the opportunities for doing so.

9.2 **Network Connection Design for Power Generating Modules**

9.2.1 The connection of new **Customers**, including **Power Generating Facility Owners**, to the **Distribution Network** should not generally increase the risk of interruption to existing **Customers**. For example, alterations to existing **Distribution Network** designs that cause hitherto normally closed circuits to have to run on open standby such that other **Customers** might become disconnected for the duration of the auto-switching times are deprecated.

9.2.2 Connection of **Power Generating Modules** to **Distribution Networks** will be subject to rules for managing the complexity of circuits. For example EREC P18 sets out the normal limits of complexity of 132kV circuits by stipulating certain restrictions to be applied when they are designed e.g. the operation of protective gear for making dead any 132kV circuit shall not require the opening of more than seven circuit breakers and these circuit breakers shall not be located at more than four different sites. Each DNO will have similar policies for managing complexity of lower voltage circuits.

9.2.3 The security requirements for the connection of **Power Generating Modules** are subject to economic consideration by the **DNO** and the **Power Generating Facility Owner.** A firm connection for **Power Generating Module** should allow the full MVA capacity to be exported via the **Distribution Network** at all times of year and after one outage on any one circuit of the **Distribution Network**. ETR 124 provides additional advice on the management of constraints and security.

9.2.4 The decision as to whether or not a firm connection is required should be by agreement between the **DNO** and the **Power Generating Facility Owner**. The **DNO** should be able to provide an indication of the likely duration and magnitude of any constraints so that the **Power Generating Facility Owner** can make an informed decision. The **Power Generating Facility Owner** should consider the financial implications of a non-firm connection against the cost of a firm connection, associated **Distribution Network** reinforcement and the risk of any constraints due to **Distribution Network** restrictions.

9.2.5 Where the **DNO** expects the **Power Generating Module** to contribute to system security, the provisions of EREC P2 and the guidance of ETR 130 will apply. In addition, the **Power Generating Module** should either remain synchronised and in parallel with the **Distribution Network** under the outage condition being considered or be capable of being resynchronised within the time period specified in EREC P2. There may be commercial issues to consider in addition to the connection cost and this may influence the technical method which is used to achieve a desired security of supply.

9.2.6 When designing a scheme to connect **a Power Generating Module**, consideration must be given to the contribution which that **Power Generating Module** will make to short circuit current flows on the **Distribution Network**. The assessment of the fault level contribution from **a Power Generating Module** and the impact on the suitability of connected switchgear are discussed in Section 9.4.

9.2.7 It is clearly important to avoid unwanted tripping of the **Power Generating Module** particularly where the **Power Generating Module** is providing **Distribution Network** or **Total System** security. The quality of supply and stability of **Power Generating Module** performance are dealt with in Sections 9.6 and 9.7 respectively.

9.2.8 **Power Generating Modules** may be connected via existing circuits to which load and/or existing **Power Generating Modules are** also connected. The duty on such circuits, including load cycle, real and reactive power flows, and voltage implications on the **Distribution Network** will need to be carefully reviewed by the **DNO**, taking account of maximum and minimum load and generation export conditions during system intact conditions and for maintenance outages of both the **Distribution Network** and **Generation Plant**. In the event of network limitations, ETR 124 provides guidance to **DNO**s on overcoming such limitations using active management solutions.

9.2.9 A **DNO** assessing a proposed connection of **a Power Generating Module** must also consider its effects on the **Distribution Network** voltage profile and voltage control employed on the **Distribution Network**. Voltage limits and control issues are discussed in Section 9.5.

9.3 Power Generating Module Performance and Control Requirements

9.3.1 The requirements of this section do not apply to **Power Generation Facilities** that are designed and installed for infrequent short term parallel operation only.

9.3.2 The design of and any changes to the schemes and settings of the different control devices of a **power generating module** with a **maximum capacity** of more than 1 MW (Type B and above) that are necessary for transmission **system stability** and for taking emergency action shall be coordinated and agreed between NETSO, the **DNO** and the **power generating facility owner**.

9.3.3 For **Embedded Power Generating Modules,** which do not constitute or contain **BM Units** that are active (ie submitting bid-offer data) in the **Balancing Mechanism**, the electrical parameters required to be achieved at the **Generation Set** terminals are defined according to the connection method and will be specified by the **DNO** with the offer for connection. The rated power output of a **Power Generating Module** should not be affected by voltage changes within the statutory limits declared by the **DNO** in accordance with the **ESQCR** unless otherwise agreed with the **DNO**.

9.3.4 Type A P**ower generating modules** connected to the **DNO's Distribution Network** shall be equipped with a logic interface (input port) in order to cease **active power** output within five seconds following an **instruction** being received at the input port. The relevant **DNO** has the right to define requirements for equipment to make this facility operable remotely.

9.3.5 To control active power output, Type B **Power Generating Nodules** shall be equipped with an interface (input port) in order to be able to reduce active power output following an instruction at the input port. The **DNO** shall have the right to specify the requirements for further equipment to allow active power output to be remotely operated.

9.3.6 Each item of a **Power Generating Module** and its associated control equipment must be designed for stable operation in parallel with the **Distribution Network**.

9.3.7 The **Power Generating Facility Owner** will notify, and keep notified, the **DNO** of the set points of the control scheme for voltage control or Power Factor control as appropriate and which have previously been agreed between the **Power Generating Facility Owner** and **DNO**. The information to be provided is detailed in Schedule 5a and Schedule 5b.

9.3.8 Load flow and **System Stability** studies may be necessary to determine any output constraints or post fault actions necessary for n-1 fault conditions and credible n-2 conditions (where n-1 and n-2 conditions are the first and second outage conditions as, for example, specified in EREC P2) involving a mixture of fault and planned outages. The **Connection Agreement** should include details of the relevant outage conditions. It may be necessary under these fault conditions, where the combination of **Power Generating Module** output, load and through flow levels leads to circuit overloading, to rapidly disconnect or constrain the **Power Generating Module** .

Frequency response

9.4.1 Under abnormal conditions automatic low-frequency load-shedding provides for load reduction down to 47Hz. In exceptional circumstances, the frequency of the **DNO's Distribution Network** could rise above 50.5 Hz. Therefore all embedded **Power Generating Facilities** should be capable of continuing to operate in parallel with the **Distribution Network** in accordance with the following:

a. 47 Hz – 47.5 Hz Operation for a period of at least 20 seconds is required each time the frequency is within this range.

b. 47.5 Hz – 49.0 Hz Operation for a period of at least 90 minutes is required each time the frequency is within this range.

c. 49.0Hz – 51.0 Hz The **Power Generating Module** must remain connected in this range

d. 51.0 Hz –51.5 Hz Operation for a period of at least 90 minutes is required each time the frequency is within this range.

e. 51.5 Hz – 52 Hz Operation for a period of at least 15 minutes is required each time the frequency is within this range.

9.4.1 Output power with falling frequency

Each **Power Generating Module**, must be capable of:

(a) continuously maintaining constant **Active Power** output for **System Frequency** changes within the range 50.5 to 49.5 Hz; and

(b) (subject to the provisions of paragraph 9.4.1) maintaining its **Active Power** output at a level not lower than the figure determined by the linear relationship shown in Figure 9.1 for **System Frequency** changes within the range 49.5 to 47 Hz for all ambient temperature changes up to and including 25$^{0}$C, such that if the **System Frequency** drops to 47 Hz the **Active Power** output does not decrease by more than 5%. In the case of a **CCGT Module**, the above requirement shall be retained down to 48.8 Hz. For **System Frequency** below 48.8 Hz, the existing requirement shall be retained for a minimum period of 5 minutes while **System Frequency** remains below that setting, and special measure(s) that may be required to meet this requirement shall be kept in service during this period. After that 5 minutes period, if **System Frequency** remains below that setting, the special measure(s) must be discontinued if there is a materially increased risk of the **Gas Turbine** tripping. The need for special measure(s) is linked to the inherent **Gas Turbine Active Power** output reduction caused by reduced shaft speed due to falling **System Frequency**. Where the need for special measures is identified in order to maintain output in line with the level identified in Figure 9.1 these measures should be still continued at ambient temperatures above 25$^{0}$C maintaining as much of the Active Power achievable within the capability of the plant.

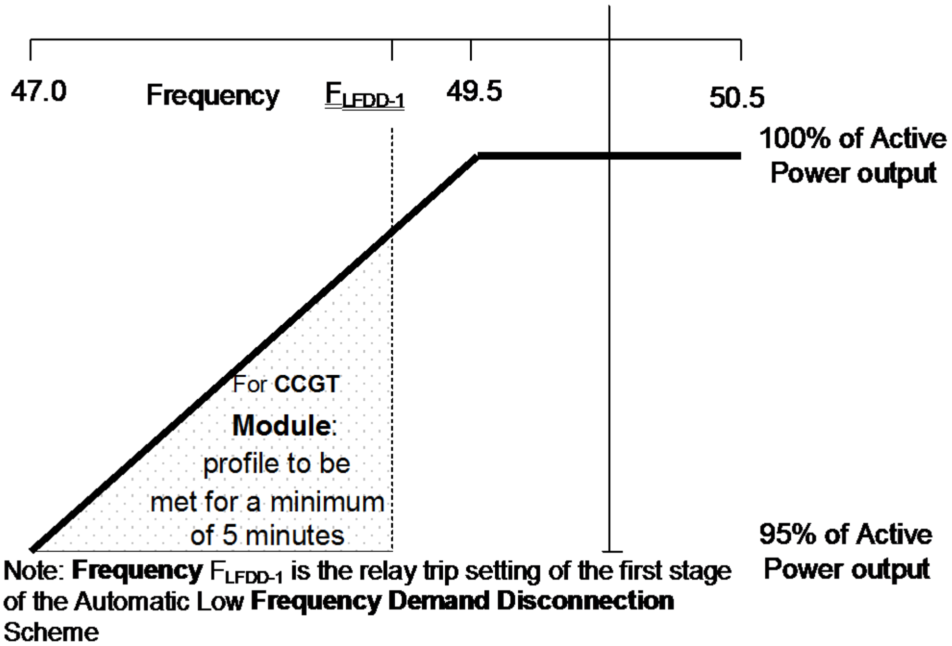


Figure 9.1

9.5 Limited Frequency Sensitive Mode – Overfrequency

9.5.1 Each **Power Generating Module** shall be capable of reducing **Active Power** output in response to **System Frequency** when this rises above 50.4Hz. For the avoidance of doubt, the provision of this reduction in **Active Power** output is not an **Ancillary Service**. Such provision is known as **Limited High Frequency Response**. The **Power Generating Module** shall be capable of operating stably during **LFSM-O** operation. When **LFSM-O** is active, the **LFSM-O** setpoint will prevail over any other active power setpoints.

9.5.2 (i) The rate of change of **Active Power** output must be at a minimum a rate of 2 percent of output per 0.1 Hz deviation of **System Frequency** above 50.4Hz (ie a Droop of 10%) as shown in Figure 9.2 below.

(ii) The reduction in Active Power output must be continuously and linearly proportional, as far as is practicable, to the excess of Frequency above 50.4 Hz and must be provided increasingly with time over the period specified in (iii) below.

(iii) As much as possible of the proportional reduction in **Active Power** output must result from the frequency control device (or speed governor) action and must be achieved within 10 seconds of the time of the **Frequency** increase above 50.4 Hz. The Power Generating Module shall be capable of initiating a Power Frequency Response with minimal delay. If the delay exceeds 2 seconds the Generator shall justify the delay, providing technical evidence to the DNO.

(iv) The residue of the proportional reduction in **Active Power** output which results from automatic action of the **Power Generating Module** output control devices other than the frequency control devices (or speed governors) must be achieved within 3 minutes for the time of the Frequency increase above 50.4Hz.

Active power frequency response capability of power-generating modules in LFSM-O

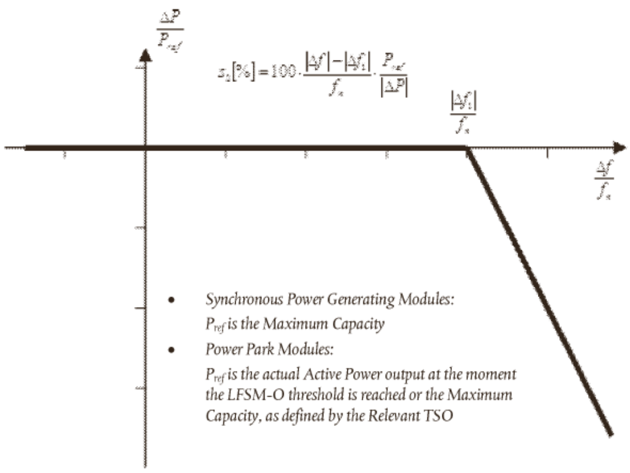


Figure 9.2: Pref is the reference active power to which ΔP is related and may be specified differently for **Synchronous Power Generating Modules** and **Power Park Modules**. ΔP is the change in **Active Power** output from the **Power Generating Module**. Fn is the nominal frequency (50Hz) in the network and Δf is the **Frequency** deviation in the network, At overfrequencies where Δf is below $\Delta f_1$ the **Power Generating Module** has to provide a negative **Active Power** output change according to droop $S_2$

9.5.3 The power generating module shall be capable of activating a power frequency response with an initial delay that is as short as possible. If that delay is greater than two seconds, the power generating facility owner shall justify the delay, providing technical evidence to the **TSO**;

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

(i) continuing operation at this level; or

(ii) further decreasing **active power output**;

9.5.5 The power generating module shall be capable of operating stably during LFSM-O operation. When LFSM-O is active, the LFSM-O setpoint will prevail over any other active power setpoints.

## 9.6 Fault Contributions and Switchgear Considerations

9.6.1 Under the **ESQCR** 2002 and the EaWR 1989 the **Power Generating Facility Owner** and the **DNO** have legal duties to ensure that their respective systems are capable of withstanding the short circuit currents associated with their own equipment and any infeed from any other connected system.

9.6.1.1 The short circuit rating of **User's Equipment** at the **Connection Point** should be not less than the design **Fault Level** of the **DNO's Distribution Network** to which it is connected. The choice of **Equipment** for connection at **Low Voltage** may take into account attenuation in the service lines as specified in Engineering Recommendation P25, "The short circuit characteristics of electricity board's low voltage distribution networks and the co-ordination of overcurrent protective devices on 230V single phase supplies up to 100 Amps" and Engineering Recommendation P26/1, "The estimation of the maximum prospective short circuit current for three phase 415V supplies". The **DNO** in the design of its **Network** will take into account the contribution to **Fault Level** of the **User's** connected **System** and **Apparatus**.

9.6.1.2 In order to permit these assessments to be carried out information should be exchanged on prospective fault power infeed and X/R ratios where appropriate at points of entry to and exit from the **DNO's Distribution Network.**

9.6.2 The **Power Generating Facility Owner** may accept that protection installed on the **Distribution Network** can help discharge some of his legal obligations relating to fault clearance and, if requested, the **DNO** should consider allowing such faults on the **Power Generating Facility Owner's** system to be detected by **DNO** protection systems and cleared by the **DNO's** circuit breaker. The **DNO** will not allow the **Power Generating Facility Owner** to close the **DNO's** circuit breaker nor to synchronise using the **DNO's** circuit breaker. In all such cases the exact nature of the protection afforded by the **DNO's** equipment should be agreed and documented. The **DNO** may make a charge for the provision of this service.

9.6.3 The design and safe operation of the **Power Generating Facility Owner's** and the **DNO's** installation's depend upon accurate assessment of the contribution to the short circuit current made by all the **Power Generating Modules** operating in parallel with the **Distribution Network** at the instant of fault and the **Power Generating Facility Owner** should discuss this with the **DNO** at the earliest possible stage.

9.6.4 Short circuit current calculations should take account of the contributions from all synchronous and asynchronous infeeds including induction motors and the contribution from inverter connected **Power Generating Module**s. The prospective short circuit 'make' and 'break' duties on switchgear should be calculated to ensure that plant is not potentially over-stressed. The maximum short circuit duty might not occur under maximum generation conditions; it may occur during planned or automatic operations carried out either on the **Distribution Network** or **Transmission System**. Studies must therefore consider all credible **Distribution Network** running arrangements which are likely to increase **Distribution Network** short circuit levels. The level of load used in the assessment should reflect committed projects as well as the existing loads declared in the **DNO'**s Long Term Development Statement (LTDS). Guidance on short circuit calculations is given in EREC G74.

9.6.5 The connection of **a Power Generating Module** can raise the **Distribution Network** reactance/resistance (X/R) ratio. In some cases, this will place a more onerous duty on switchgear by prolonging the duration of the DC component of fault current from fault inception. This can increase the proportion of the DC component of the fault current and delay the occurrence of current zeros with respect to voltage zeros during the interruption of fault current. The performance of connected switchgear must be assessed to ensure safe operation of the **Distribution Network**. The performance of protection may also be impaired by partial or complete saturation of current transformers resulting from an increase in **Distribution Network** X/R ratio.

9.6.6 Newly installed protection systems and circuit breakers for **Power Generating Module** connections should be designed, specified and operated to account for the possibility of out-of-phase operation. It is expected that the **DNO'**s metering/interface circuit breaker will be specified for this duty, but in the case of existing circuit breakers on the **Distribution Network**, the **DNO** will need to establish the possibility or otherwise of the **DNO**s protection (or the **Power Generating Facility Owner**'s protection if arranged to trip the **DNO'**s circuit breaker) initiating a circuit breaker trip during a period when one of more **Power Generating Module**s might have lost **Synchronism** with the **Total System**. Where necessary, switchgear replacement, improved security arrangements and other control measures should be considered to mitigate this risk.

9.6.7 When connection of **a Power Generating Module** is likely to increase short circuit currents above **Distribution Network** design ratings, consideration should be given to the installation of reactors, sectionalising networks, connecting the **Power Generating Module** to part of the **Distribution Network** operating at a higher voltage, changing the **Power Generating Module** specification or other means of limiting short circuit current infeed. If fault limiting measures are not cost effective or feasible or have a material detrimental effect on other users, **Distribution Network** plant with the potential to be subjected to short circuit currents in excess of its rating should be replaced or reference made to the relevant manufacturer to determine whether or not the existing plant rating(s) can be enhanced. In situations where **Distribution Network** design ratings would be exceeded in infrequent but credible **Distribution Network** configurations, then constraining the **Power Generating Module** off during periods of such **Distribution Network** configurations may provide a suitable solution. When assessing short circuit currents against **Distribution Network** design ratings, suitable safety margins should be allowed to cater for tolerances that exist in the **Distribution Network** data and **Power Generating Module** parameters used in system modelling programs. On request from a **Power Generating Facility Owner** the **DNO** will provide the rationale for determining the value of a specific margin being used in **Distribution Network** studies.

9.6.8 For busbars with three or more direct connections to the rest of the **Total System**, consideration may be given to reducing fault levels by having one of the connections 'open' and on automatic standby. This arrangement will only be acceptable provided that the loss of one of the remaining circuits will not cause the group to come out of **Synchronism**, cause unacceptable voltage excursions or overloading of **Distribution Network** or **Transmission System** plant and equipment. The use of the proposed **Power Generating Module** to prevent overloading of **Distribution Network** plant and equipment should be considered with reference to EREC P2.

9.6.9 Disconnection of **a Power Generating Module** must be achieved by the separation of mechanical contacts unless the disconnection is at **Low Voltage** and the equipment at the point of disconnection contains appropriate self monitoring of the point of disconnection, in which case an appropriate electronic means such as a suitably rated semiconductor switching device would be acceptable. The self monitoring facility shall incorporate fail safe monitoring to check the voltage level at the output stage. In the event that the solid state switching device fails to disconnect the **Power Generating Module**, the voltage on the output side of the switching device shall be reduced to a value below 50V within 0.5s. For the avoidance of doubt this disconnection is a means of providing LoM disconnection and not as a point of isolation to provide a safe system of work.

### 9.6.10 Capacitive and Inductive Effects

The **User** shall, when applying to make a connection, provide the **DNO** with information as detailed in DPC8. Details will be required of capacitor banks and reactors connected at **HV** which could affect the **DNO's Distribution Network** and which it is proposed to connect if agreed by the **DNO**. When requested by the **DNO** details shall also be provided of distributed circuit capacitance and inductance. Sufficient detail is required for the following:-

(a) To verify that controlling **Equipment** of the **DNO's Distribution Network** is suitably rated.

(b) To show that the performance of the **DNO's Distribution Network** will not be impaired.

(c) To ensure that arc suppression coils when used by the **DNO** for **System** earthing purposes are correctly installed and operated.

## 9.7 Fault Ride through

9.7.1 Paragraphs 9.7.1 to 9.7.8 inclusive set out the fault ride through, principles and concepts applicable to Type B **Synchronous Power Generating Modules** and **Power Park Modules**, subject to disturbances from faults on the transmission system of up to 140ms in duration.

9.7.2 Each **Synchronous Power Generating Module** and **Power Park Module** is required to remain connected and stable for any balanced and unbalanced fault where the voltage at the **Connection Point** remains on or above the heavy black line shown in Figures 9.3 and 9.4 below.

9.7.3 The voltage against time curves defined in 9.7.4 – 9.7.7 expresses the lower limit (expressed as the ratio of its actual value and its reference 1pu) of the actual course of the phase to phase voltages (or phase to earth voltage in the case of asymmetrical/unbalanced faults) on the network voltage level at the **Connection Point** during a symmetrical or asymmetrical/unbalanced fault, as a function of time before, during and after the fault.

9.7.4

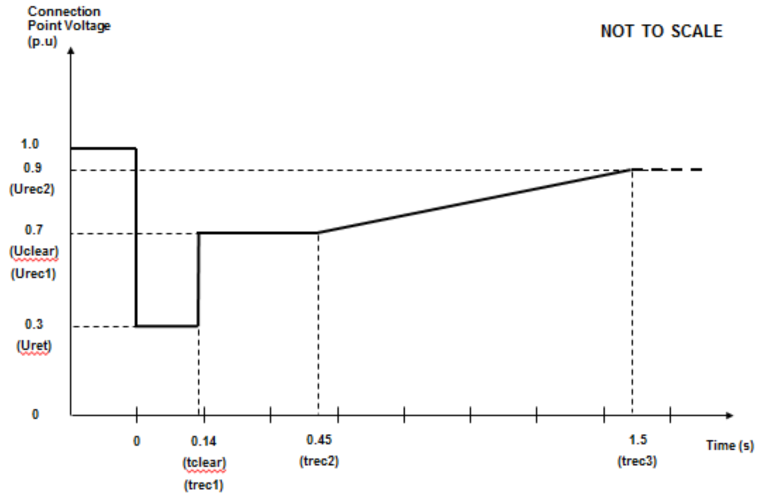


Figure 9.3 - Voltage against time curve applicable to Type B **Synchronous Power Generating Modules**

9.7.5 Voltage against time parameters applicable to Type B **Synchronous Power Generating Modules**

| Voltage parameters (pu) | | Time parameters (seconds) | |
|---|---|---|---|
| Uret | 0.3 | tclear | 0.14 |
| Uclear | 0.7 | trec1 | 0.14 |
| Urec1 | 0.7 | trec2 | 0.45 |
| Urec2 | 0.9 | trec3 | 1.5 |

9.7.6

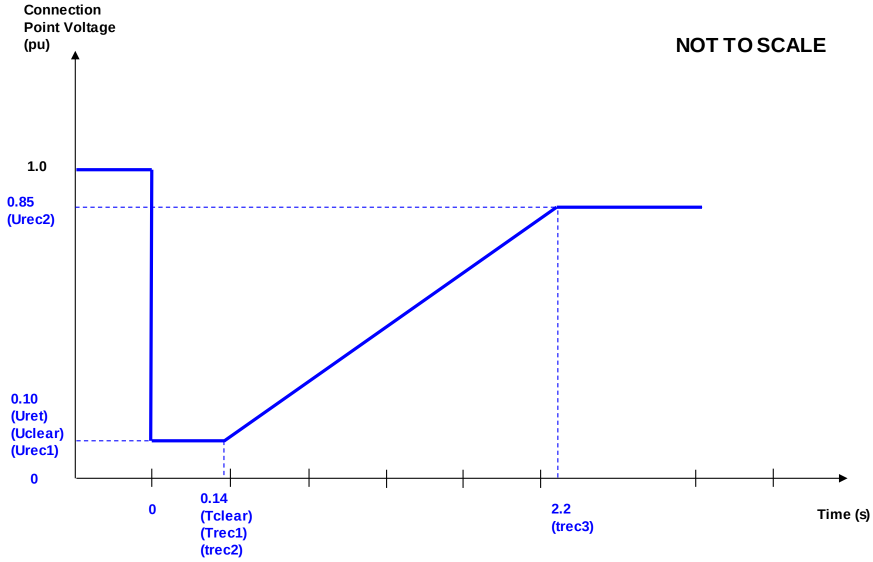


Figure 9.4 - Voltage against time curve applicable to Type B **Power Park Modules**

9.7.7 Voltage against time parameters applicable to Type B **Power Park Modules**

| Voltage parameters (pu) | | Time parameters (seconds) | |
|---|---|---|---|
| Uret | 0.1 | tclear | 0.14 |
| Uclear | 0.1 | trec1 | 0.14 |
| Urec1 | 0.1 | trec2 | 0.14 |
| Urec2 | 0.85 | trec3 | 2.2 |

9.7.8 In addition to the requirements in 9.7.4 to 9.7.7:

(i) Each Type B **Power Generating Module** shall be capable of satisfying the above requirements when operating at **Rated MW** output and maximum leading **Power Factor**.

(ii) The pre-fault voltage shall be taken to be 1.0pu and the post fault voltage shall be 0.9pu unless a higher value is specified in the Connection Agreement.

(iii) **The DNO** will publish fault level data under maximum and minimum demand conditions in the Long Term Development Statements. To allow a **User** to model the fault ride through performance of its Type B **Power Generating Modules**, **the DNO** will provide generic fault level values derived from typical cases. Where necessary, on reasonable request the DNO will specify the pre-fault and post fault short circuit capacity (in MVA) at the **Connection Point** and will provide additional network data as may reasonably be required for the **User** to undertake such study work.

(iv) Each **Generator** shall satisfy the requirements in 9.7.4 – 9.7.7 unless the protection schemes and settings for internal electrical faults requires disconnection of the Type B **Power Generating Module** from the network. The protection schemes and settings should not jeopardise fault ride through performance as specified in 9.7.4 – 9.7.7. The undervoltage protection at the **Connection Point** shall be set by the **Power Generating Facility Owner** according to the widest possible range unless **the DNO** has agreed to narrower settings which shall be pursuant to the terms of the **Connection Agreement**. All protection settings associated with undervoltage protection shall be agreed between the DNO and the Power Generating Facility Owner.

(v) In addition to the requirements of 9.7.4 – 9.7.8 each Type B **Power Generating Module** shall be designed such within 0.5 seconds of restoration of the voltage at the **Connection Point** to 90% of nominal voltage or greater, **Active Power** output shall be restored to at least 90% of the level immediately before the fault. Once **Active Power** output has been restored to the required level, **Active Power** oscillations shall be acceptable provided that:

- The total Active Energy delivered during the period of the oscillations is at least that which would have been delivered if the **Active Power** was constant
- The oscillations are adequately damped.

(vi) For Type B **Power Park Modules**, comprising switched reactive compensation equipment (such as mechanically switched capacitors and reactors), such switched reactive compensation equipment shall be controlled such that it is not switched in or out of service during the fault but may act to assist in post fault voltage recovery.

9.7.9 In addition to paragraphs 9.7.1 – 9.7.8 any **Power Generating Module** or **Power Generating Facility** connected to the **DNO's Distribution Network**, where it has been agreed between the **DNO** and the **Power Generating Facility Owner** that the **Power Generating Facility** will contribute to the **DNO**'s **Distribution Network** security, may be required to withstand, without tripping, the effects of a close up three phase fault and the Phase (Voltage) Unbalance imposed during the clearance of a close-up phase-to-phase fault , in both cases cleared by the **DNO**'s main protection. The **DNO** will advise the **Embedded Power Generating Facility** in each case of the likely tripping time of the **DNO**'s protection, and for phase-phase faults, the likely value of Phase (Voltage) Unbalance during the fault clearance time.

In the case of phase to phase faults on the **DNO**'s system that are cleared by **System** back-up **Protection** which will be within the **Plant** short time rating on the **DNO**'s **Distribution Network** the **DNO**, on request during the Connection Agreement process, will advise the Embedded Power Generating Facility Owner of the expected Phase Voltage Unbalance.

## 9.8 Voltage Limits and Control

9.8.1 Where **a Power Generating Module** is remote from a network voltage control point it may be required to withstand voltages outside the normal statutory limits. In these circumstances, the **DNO** should agree with the **Power Generating Facility Owner** the declared voltage and voltage range at the **Connection Point**. Immunity of the **Power Generating Module** to voltage changes of ± 10% of the declared voltage is recommended, subject to design appraisal of individual installations.

9.8.2 The connection of a **Power Generating Module** to the **Distribution Network** shall be designed in such a way that operation of the **Power Generating Module** does not adversely affect the voltage profile of and voltage control employed on the **Distribution Network**. ETR 126 provides **DNO**s with guidance on active management solutions to overcome voltage control limitations. Information on the voltage regulation and control arrangements will be made available by the **DNO** if requested by the **User.**

9.8.3 When supplying **Rated MW** all Type B **Power Generating Modules** must be capable of continuous operation at any points between the limits of 0.95 Power Factor lagging and 0.95 Power Factor leading at the **Connection Point** unless otherwise specified by the **DNO** in the **Connection Agreement.**

9.8.4 At Active Power output levels other than **Rated MW**, all alternators within a Type B **Synchronous Power Generating Modules** must be capable of continuous operation at any point between the Reactive Power capability limits identified on the **Generator Performance Chart** unless otherwise agreed with the **DNO**.

9.8.5 At Active Power output levels other than **Rated MW**, all Type B **Power Park Modules** must be capable of continuous operation at any point between the **Reactive Power** capability limits identified on the P-Q operating chart unless otherwise agreed with the **DNO**.

9.8.6 Each Type B **Synchronous Power Generating Module** shall be equipped with a permanent automatic excitation system that can provide constant alternator terminal voltage at a selectable setpoint without instability over the entire operating range of the Type B Synchronous **Power Generating Module**.

9.8.7 The **DNO** will specify in the **Connection Agreement** if the control system of the Type B **Synchronous Power Generating Module** or **Power Park Module** shall contribute to voltage control or Reactive Power control or Power Factor control at the **Connection Point** (or other defined busbar). The performance requirements of the control system including droop (where applicable) shall be specified in the **Connection Agreement**.

9.8.8 The final responsibility for control of **Distribution Network** voltage does however remain with the **DNO**.

9.8.9 Automatic Voltage Control (AVC) schemes employed by the **DNO** assume that power flows from parts of the **Distribution Network** operating at a higher voltage to parts of the **Distribution Network** operating at lower voltages. Export from **Power Generating Modules** in excess of the local loads may result in power flows in the reverse direction. In this case AVC referenced to the low voltage side will not operate correctly without an import of reactive power and relay settings appropriate to this operating condition. When load current compounding is used with the AVC and the penetration level of **Power Generating Modules** becomes significant compared to normal loads, it may be necessary to switch any compounding out of service.

9.8.10 **Power Generating Modules** can cause problems if connected to networks employing AVC schemes which use negative reactance compounding and line drop compensation due to changes in active and reactive power flows. ETR 126 provides guidance on connecting generation to such networks using techniques such as removing the generation circuit from the AVC scheme using cancellation CTs.

9.8.11 An agreement between the **DNO** and the **Power Generating Facility Owner** may allow the use of voltage control techniques other than those previously mentioned. Such an agreement would normally be reached during the negotiating stage of the connection.

9.8.12 The **Step Voltage Change** caused by the connection and disconnection of **Power Generating Modules** from the **Distribution Network** must be considered and be subject to limits to avoid unacceptable voltage changes being experienced by other **Customers** connected to the **Distribution Network**. The magnitude of a **Step Voltage Change** depends on the method of voltage control, types of load connected and the presence of local generation.

Typical limits for **Step Voltage Change** caused by the connection and disconnection of any **Customers** equipment to the **Distribution Network** should be ± 3% for infrequent planned switching events or outages in accordance with EREC P28. For unplanned outages such faults it will generally be acceptable to design to a **Step Voltage Change** of ±10%.

A voltage step change should be considered to be the change from the initial voltage level to the resulting voltage level after all the **Power Generating Module automatic voltage regulator** and static VAR compensator actions, and transient decay (typically 5 seconds after the fault clearance or system switching) have taken place, but before any other automatic or manual tap-changing and switching actions have commenced

9.8.13 The voltage depression arising from transformer magnetising inrush current is a short-time phenomenon not generally easily captured by the definition of **Step Voltage Change** used in this document. In addition the size of the depression is dependent on the point on wave of switching and the duration of the depression is relatively short in that the voltage recovers substantially in less than one second.

9.8.14 **Customer Installations** should be designed such that transformer magnetising inrush current associated with normal routine switching operations does not cause voltage fluctuations outside those in EREC P28 (i.e. a maximum of ±3%). To achieve this it may be necessary to install switchgear so that sites containing multiple transformers can be energised in stages.

9.8.15 Situations will arise from time to time when complete sites including a significant presence of transformers are energised as a result of post fault switching, post fault maintenance switching, carrying out commissioning tests on **Distribution Network** or on the **Customer**'s **Installation**. In these situations it will generally be acceptable to design to an expected depression of around 10% recognising that a worst case energisation might be a larger depression, on the basis that such events are considered to be rare and it is difficult to predict the exact depression because of the point on wave switching uncertainty. Should these switching events become more frequent than once per year then the design should revert to aiming to limit depressions to less than 3%.

9.8.16 These threshold limits should be complied with at the **Point of Common Coupling** as required by EREC P28.

## 9.9 Voltage Disturbances

Under fault and circuit switching conditions the rated **Frequency** component of voltage may fall or rise transiently. The fall or rise in voltage will be affected by the method of earthing of the neutral point of the **DNO's Distribution Network** and voltage may fall transiently to zero at the point of fault. BS EN 50160:2010 'Voltage Characteristics of Electricity Supplied by Public Distribution Systems', as amended from time to time, contains additional details of the variations and disturbances to the voltage which shall be taken into account in selecting **Equipment** from an appropriate specification for installation on or connected to the **System**.

### 9.10 Voltage Stability

9.10.1 The **DNO** in coordination with **NGET** shall have the right to specify that a Type B **Power Park Module** that is connected to the **DNO's Distribution Network** be capable of providing **fast fault current** at the **connection point** in case of symmetrical (3-phase) faults, under the following conditions:

9.10.2 (i) the **Power Park Module** shall be capable of activating the supply of **fast fault current** either by:

– ensuring the supply of the **fast fault current** at the connection point; or

– measuring voltage deviations at the terminals of the individual units of the power park module and providing a **fast fault current** at the terminals of these units;

9.10.3 (ii) the **DNO** in coordination with **NGET** shall specify:

– how and when a voltage deviation is to be determined as well as the end of the voltage deviation;

– the characteristics of the **fast fault current**, including the time domain for measuring the voltage deviation and fast fault current, for which current and voltage may be measured differently from the following methods;

- voltage measured as the root-mean-square value of the positive sequence phase-to-phase voltages at fundamental frequency;
- current measured by the root-mean-square value of the positive sequence of the phase current at fundamental frequency.

– the timing and accuracy of the **fast fault current**, which may include several stages during a fault and after its clearance;

9.10. With regard to the supply of fast fault current in case of

4 asymmetrical (1-phase or 2-phase) faults, the **DNO** in coordination with **NETSO** shall have the right to specify a requirement for asymmetrical current injection.

9.11 **Additional Requirements**

9.11.1 **Type B Power Park Modules** shall fulfil the following additional requirements in relation to robustness:

(a) providing post-fault **active power** recovery to meet **the TSO's** specification including:

(i) when the post-fault **active power** recovery begins, based on a voltage criterion;

(ii) a maximum allowed time for **active power** recovery; and

(iii) a maximum allowed time for **active power** recovery.

9.11.2 (b) the specifications shall be in accordance with the following principles:

(i) interdependency between **fast fault current** requirements according to Paragraphs 9.10.3 to 9.10.5 and active power recovery;

(ii) dependence between **active power** recovery times and duration of voltage deviations;

(iii) a specified limit of the maximum allowed time for **active power** recovery;

(iv) adequacy between the level of voltage recovery and the minimum magnitude for **active power** recovery; and

(v) adequate damping of active power oscillations.

9.12 Power Quality

9.12.1 Introduction

The connection and operation of **Power Generating Modules** may cause a distortion of the **Distribution Network** voltage waveform resulting in voltage fluctuations, harmonics or phase voltage unbalance.

9.12.2 Flicker

Where the input motive power of the **Power Generating Module** may vary rapidly, causing corresponding changes in the output power, flicker may result. The operation of a **Power Generating Module** including synchronisation, run-up and desynchronisation shall not result in flicker that breaches the limits for flicker in EREC P28.

The fault level of the **Distribution Network** needs to be considered to ensure that the emissions produced by the **Power Generating Module** do not cause a problem on the **Distribution Network**.

The **DNO** will use these declared figures to calculate the required maximum supply impedance required for the connection to comply with EREC P28. This calculation may show that the voltage fluctuations will be greater than those permitted and hence reinforcement of the **Distribution Network** may be required before the **Power Generating Module** can be connected.

9.12.2 For wind turbines, flicker testing should be carried out during the performance tests specified in BS EN 61400-12. Flicker data should be

.1 recorded from wind speeds of $1ms^{-1}$ below cut-in to 1.5 times 85% of the rated power. The wind speed range should be divided into contiguous bins of $1ms^{-1}$ centred on multiples of $1ms^{-1}$. The dataset shall be considered complete when each bin includes a minimum of 10 minutes of sampled data.

The highest recorded values across the whole range of measurements should be used as inputs to the calculations described in BS EN 61000-3-11 to remove back ground flicker values. Then the required maximum supply impedance values can be calculated as described in 13.1. Note that occasional very high values may be due to faults on the associated HV network and may be discounted, though care should be taken to avoid discounting values which appear regularly.

9.12.2 For technologies other than wind, the controls or automatic programs used shall produce the most unfavourable sequence of voltage changes for the purposes of the test.

9.12.3 Harmonic Emissions

Harmonic voltages and currents produced within the **Power Generating Facility Owner**'s system may cause excessive harmonic voltage distortion in the **Distribution Network**. The **Power Generating Facility Owner**'s installation must be designed and operated to comply with the planning criteria for harmonic voltage distortion as specified in EREC G5. EREC G5, like all planning standards referenced in this recommendation, is applicable at the time of connection of additional equipment to a **Customer**'s **Installation**.

The **DNO** will use these declared figures to calculate the required maximum supply impedance required for the connection to comply with BS EN 61000-3-12 and will use this data in their design of the connection for the **Power Generating Module**. This standard requires a minimum ratio between source fault level and the size of the **Power Generating Module**, and connections in some cases may require the installation of a transformer between 2 and 4 times the rating of the **Power Generating Module** in order to accept the connection to a **DNO's Distribution Network.**

Alternatively, if the harmonic emissions are low and they are shown to meet the requirements of BS EN 61000-3-2 then there will be no need to carry out the fault level to **Power Generating Module** size ratio check. **Power Generating Module**s meeting the requirements of BS EN 61000-3-2 will need no further assessment with regards to harmonics.

9.12.4 Where the **Power Generating Module** is connected via a long cable circuit the likelihood of a resonant condition is greatly increased, especially at 132kV. This arises from the reaction of the transformer inductance with the cable capacitance. Resonance is likely in the low multiples of the fundamental frequency (8th-11th harmonic). The resonant frequency is also a function of the **Total System** fault level. If there is the possibility that this can change significantly eg by the connection of another **Power Generating Module** then a full harmonic study should be carried out.

9.12.5 Voltage imbalance

EREC P29 is a planning standard which sets the **Distribution Network** compatibility levels for voltage unbalance caused by uneven loading of three phase supply systems. **Power Generating Modules** should be capable of performing satisfactorily under the conditions it defines. The existing voltage unbalance on an urban **Distribution Network** rarely exceeds 0.5% but higher levels, in excess of 1%, may be experienced at times of high load and when outages occur at voltage levels above 11kV. 1% may exist continuously due to unbalance of the system impedance (common on remote rural networks). In addition account can be taken of the neutralising effect of rotating plant, particularly at 11 kV and below.

9.12.6 The level of voltage unbalance at the **Point of Common Coupling** should be no greater than 1.3% for systems with a nominal voltage below 33kV, or 1% for other systems with a nominal voltage no greater than 132kV. Overall, voltage unbalance should not exceed 2% when assessed over any one minute period. EREC P29, like all planning standards, is applicable at the time of connection.

9.12.6.1 For **Power Generating Facilities** of 50kW or less section 7.5 of this document specifies maximum unbalance of **Power Generating Modules**. Where these requirements are met then no further action is required by the **Power Generating Facility Owner**.

9.12.7 Power factor correction equipment is sometimes used with asynchronous **Power Generating Modules** to decrease reactive power flows on the **Distribution Network**. Where the power factor correction equipment is of a fixed output, stable operating conditions in the event of loss of the **DNO** supply are extremely unlikely to be maintained, and therefore no special protective actions are required in addition to the standard protection specified in this document.

9.12.8 DC Injection

The effects of, and therefore limits for, DC currents injected into the **Distribution Network** is an area currently under investigation by **DNOs**. Until these investigations are concluded the limit for DC injection is less than 0.25% of the AC rating per **Power Generating Module**.

The main source of these emissions are from transformer-less **Inverters**. Where necessary DC emission requirements can be satisfied by installing a transformer on the AC side of an **Inverter**.

9.13 System Stability

9.13.1 Instability in **Distribution Networks** may result in unacceptable quality of supply and tripping of **Customer**'s plant. In severe cases, instability may cascade across the **Distribution Network**, resulting in widespread tripping and loss of demand and generation. There is also a risk of damage to plant.

9.13.2 In general, **System Stability** is an important consideration in the design of **Power Generating Module** connections to the **Distribution Network** at 33kV and above. Stability considerations may also be appropriate for some **Power Generating Module** connections at lower voltages. The risks of instability generally increase as **Power Generating Module** capacity increases relative to the fault level infeed from the **Distribution Network** at the **Connection Point**.

9.13.3 **System Stability** may be classified into several forms, according firstly to the main system variable in which instability can be observed, and secondly to the size of the system disturbance. In **Distribution Networks**, the forms of stability of interest are rotor angle stability and voltage stability.

Rotor angle stability refers to the ability of synchronous machines in an interconnected system to remain in **Synchronism** after the system is subjected to a disturbance.

Voltage stability refers to the ability of a system to maintain acceptable voltages throughout the system after being subjected to a disturbance.

9.13.4 Both rotor angle stability and voltage stability can be further classified according to the size of the disturbance.

Small-disturbance stability refers to the ability of a system to maintain stability after being subjected to small disturbances such as small changes in load, operating points of **Power Generating Module**s, transformer tap-changing or other normal switching events.

Large-disturbance stability refers to the ability of a system to maintain stability after being subjected to large disturbances such as short-circuit faults or sudden loss of circuits or **Power Generating Module**s.

9.13.5 Traditionally, large-disturbance rotor angle stability (also referred to as transient stability) has been the form of stability predominantly of interest in **Distribution Network**s with synchronous machines. However, it should be noted that the other forms of stability may also be important and may require consideration in some cases.

9.13.6 It is recommended that **a Power Generating Module** and its connection to the **Distribution Network** be designed to maintain stability of the **Distribution Network** for a defined range of initial operating conditions and a defined set of system disturbances.

The range of initial operating conditions should be based on those which are reasonably likely to occur over a year of operation. Variables to consider include system loads, system voltages, system outages and configurations, and **Power Generating Module** operating conditions.

The system disturbances for which stability should be maintained should be selected on the basis that they have a reasonably high probability of occurrence. It is recommended that these include short-circuit faults on single **Distribution Network** circuits (such as transformers, overhead lines and cables) and busbars, that are quickly cleared by main protection.

With the **System** in its normal operating state, it is desirable that all **Power Generation Modules** remain connected and stable for any of the following credible fault outages,

(a) any one single circuit overhead line, transformer feeder or cable circuit, independent of length,

(b) any one transformer or reactor,

(c) any single section of busbar at or nearest the point of connection where busbar protection with a total clearance time of less than 200ms is installed,

(d) if demand is to be secured under a second circuit outage as required by ER P2/6, fault outages (a) or (b), overlapping with any pre-existing first circuit outage, usually for maintenance purposes. In this case the combination of circuit outages considered should be that causing the most onerous conditions for **System Stability**, taking account of the slowest combination of main protection, circuit breaker operating times and strength of the connections to the system remaining after the faulty circuit or circuits have been disconnected

It should be noted that it is impractical and uneconomical to design for stability in all circumstances. This may include double circuit fault outages and faults that are cleared by slow protection. **Power Generating Modules** that become unstable following system disturbances should be disconnected as soon as possible.

9.13.7 Any **Generation Set** that causes the **System** to become unstable under fault conditions must be rapidly disconnected to reduce the risk of **Plant** damage and disturbance to the **System**.

9.13.8 Various measures may be used, where reasonably practicable, to prevent or mitigate system instability. These may include **Distribution Network** and **Power Generating Module** solutions, such as:

- improved fault clearance times by means of faster protection;
- improved performance of **Power Generating Module** control systems (excitation and governor/prime mover control systems; **Power System Stabilisers** to improve damping);
- improved system voltage support (provision from either **Power Generating Module** or **Distribution Network** plant);
- reduced plant reactance's (if possible);
- Protection to identify pole-slipping;
- increased fault level infeed from the **Distribution Network** at the **Connection Point**.

In determining mitigation measures which are reasonably practicable, due consideration should be given to the cost of implementing the measures and the benefits to the **Distribution Network** and **Customers** in terms of reduced risk of system instability.

9.14 Island Mode

9.14.1 A fault or planned outage, which results in the disconnection of a **Power Generating Module**, together with an associated section of **Distribution Network**, from the remainder of the **Total System**, creates the potential for island mode operation. It will be necessary for the **DNO** to decide, dependent on local network conditions, if it is desirable for the

**Users** to continue to generate onto the islanded **DNO's Distribution Network**. The key potential advantage of operating in Island Mode is to maintain continuity of supply to the portion of the **Distribution Network** containing the **Power Generating Module**. The principles discussed in this section generally also apply where **Generation Plant** on a **Customer**'s site is designed to maintain supplies to that site in the event of a failure of the **DNO** supply.

9.14.2 When considering whether **Power Generating Modules** can be permitted to operate in island mode, detailed studies need to be undertaken to ensure that the islanded system will remain stable and comply with all statutory obligations and relevant planning standards when separated from the remainder of the **Total System**. Before operation in island mode can be allowed, a contractual agreement between the **DNO** and **Power Generating Facility Owner** must be in place and the legal liabilities associated with such operation must be carefully considered by the **DNO** and the **Power Generating Facility Owner**. Consideration should be given to the following areas:

a. load flows, voltage regulation, frequency regulation, voltage unbalance, voltage flicker and harmonic voltage distortion;

b. earthing arrangements;

c. short circuit currents and the adequacy of protection arrangements;

d. **System Stability**;

e. resynchronisation to the **Total System**;

f. safety of personnel.

9.14.3 Suitable equipment will need to be installed to detect that an island situation has occurred and an intertripping scheme is preferred to provide absolute discrimination at the time of the event. Confirmation that a section of **Distribution Network** is operating in island mode, and has been disconnected from the **Total System**, will need to be transmitted to the **Power Generating Module(s)** protection and control schemes.

9.14.4 The **ESQCR** requires that supplies to **Customers** are maintained within statutory limits at all times ie when they are supplied normally and when operating in island mode. Detailed system studies including the capability of the **Power Generating Module** and its control / protections systems will be required to determine the capability of the **Power Generating Module** to meet these requirements immediately as the island is created and for the duration of the island mode operation.

9.14.5 The ESQCR also require that **Distribution Networks** are earthed at all times. **Power Generating Facility Owner**s, who are not permitted to operate their installations and plant with an earthed star-point when in parallel with the **Distribution Network**, must provide an earthing transformer or switched star-point earth for the purpose of maintaining an earth on the system when islanding occurs. The design of the earthing system that will exist during island mode operation should be carefully considered to ensure statutory obligations are met and that safety of the **Distribution Network** to all users is maintained. Further details are provided in Section 8.

9.14.6 Detailed consideration must be given to ensure that protection arrangements are adequate to satisfactorily clear the full range of potential faults within the islanded system taking into account the reduced fault currents and potential longer clearance times that are likely to be associated with an islanded system.

9.14.7 Switchgear shall be rated to withstand the voltages which may exist across open contacts under islanded conditions. The **DNO** may require interlocking and isolation of its circuit breaker(s) to prevent out of phase voltages occurring across the open contacts of its switchgear. Intertripping or interlocking should be agreed between the **DNO** and the **Power Generating Facility Owner** where appropriate.

9.14.8 It will generally not be permissible to interrupt supplies to **DNO Customers** for the purposes of resynchronisation. The design of the islanded system must ensure that synchronising facilities are provided at the point of isolation between the islanded network and the **DNO** supply. Specific arrangements for this should be agreed and recorded in the **Connection Agreement** with the **DNO**. If no facilities exist for the subsequent resynchronisation with the rest of the **DNO's Distribution Network** then the **User** will under **DNO instruction**, ensure that the **Power Generating Module** is disconnected for re-synchronisation.

## 9.16 Technical Requirements for Type C Power Generating Modules

Where a **Power Generating Facility Owner** in respect of a **Power Generating Module** connected to the DNO network is a party to the **CUSC** this section 9.16 will not apply.

### 9.15 Black Start Capability

The **National Electricity Transmission System** will be equipped with **Black Start Stations** (in accordance with the **Distribution Operating Code** DOC 9). It will be necessary for each User to notify the DNO if its **Power Generating Module** has a restart capability without connection to an external power supply, unless the **User** shall have previously notified the **TSO** accordingly under the **Grid Code**. Such generation may be registered by the **TSO** as a **Black Start Station**.

9.16.1.1 In addition to the requirements in this document, the **DNO** has an obligation under CC 3.3 of the **Grid Code** to ensure that all relevant **Grid Code** Connection Condition requirements are met by Embedded **Type CPower Generating Modules**. These requirements are summarised in ECC 3.3 of the **Grid Code**. It is incumbent on Embedded **Type C Power Generating Modules** to comply with the relevant **Grid Code** requirements listed in CC3.4 of the **Grid Code** as part of compliance with this **Distribution Code**.

9.16 Where data is required by **NETSO** from Embedded **Type C Power**

.1.2 **Generating** Modules, nothing in the **Grid Code** or **Distribution Code** precludes the **Power Generating Facility Owner** from providing the information directly to **NETSO** in accordance with **Grid Code** requirements. However, a copy of the information should always be provided in parallel to the **DNO**.

9.16.2 **Grid Code Connection Conditions Compliance**

The technical designs and parameters of the Embedded **Type C Power Generating Modules** will comply with the relevant Connection Conditions of the **Grid**. A statement to this effect, stating compliance with OC5.8 of the **Grid Code** is required to be presented to the **DNO** for onward transmission to **NETSO**, before commissioning of the **Power Station**. Note that the statement might need to be resubmitted post commissioning when assumed values etc have been confirmed.

9.16.2.1 Should the **Power Generating Facility Owner** make any material change to such designs or parameters as will have any effect on the statement of compliance referred to in 9.16.2 the **Power Generating Facility Owner** must notify the change to the **DNO**, as soon as reasonably practicable, who will in turn notify **NETSO**.

9.16.2.2 Tests to ensure **Grid Code** compliance may be specified by **NETSO** in accordance with the **Grid Code**. It is the **Power Generating Facility Owner's** responsibility to carry out these tests.

9.16.2.3 Where **the TSO** can reasonably demonstrate that for **Total System** stability issues the Embedded **Type C Power Generating** Modules should be fitted with a **Power System Stabiliser**, **NETSO** will notify the **DNO** who will then require it to be fitted for compliance with this section 9.16.2.3

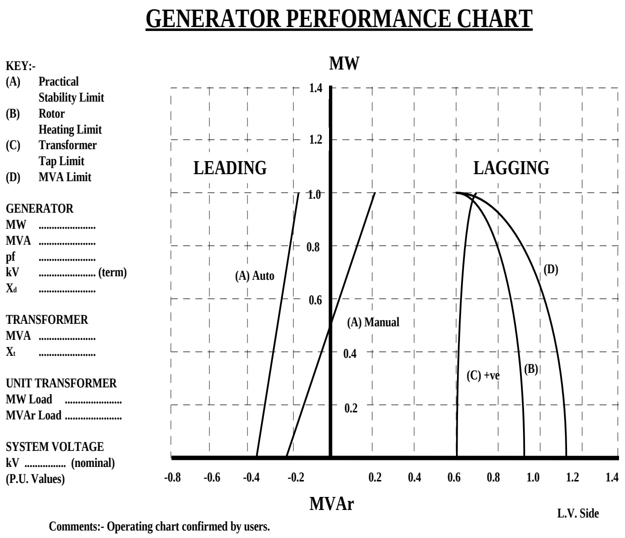


**FIGURE 1**

9.17 **Specification of Equipment, Overhead Lines and Underground Cables**

(a) The principles of design, manufacture, testing and installation of distribution **Equipment**, overhead lines and underground cables, including quality requirements, shall conform to applicable statutory obligations and shall comply with relevant **CENELEC** standards, **IEC** publications, European and British Standards. Further advice will be made available upon request to the **DNO**.

(b) The documents specified in paragraph (a) contain options for purchaser selection which together with other requirements that are necessary to meet **System** design needs, shall be specified so as to provide performances and ratings in line with **Electricity Supply Industry (ESI)** Technical Specifications (some of which are published as **Electricity Supply Industry (ESI)** Standards), British Electricity Board Specifications, Engineering Recommendations and Area Chief Engineers (ACE) Reports and Engineering Technical Reports and **Electricity Supply Industry (ESI)** documents as listed in Annex 1 of the **Distribution Code** or such other specifications as the **DNO** may adopt from time to time by agreement with the **Authority**.

(c) The specifications of **Equipment**, overhead lines and cables shall be such as to permit **Operation** of the **DNO's Distribution Network** within the **Safety Management System** of the **DNO**, details of which will be made available by the **DNO** upon request.

(d) **Equipment** shall be suitable for use at the operating **Frequency**, within the intended operating voltage range and at the design short-circuit rating of the **DNO's Distribution Network** to which it is connected having due regard to fault carrying capabilities and making and breaking duties. In appropriate circumstances, details of the **System** to which connection is to be made will be provided by the **DNO**. Guidance on the short circuit characteristics of the three phase **Low Voltage** system and associated supplies is provided in **Electricity Supply Industry** engineering publications, including Item 8 in DGD Annex 1 Engineering Recommendation P26/1, "The estimation of the maximum prospective short circuit current for three phase 415V supplies".

(f) Cables**,** overhead lines transformers and other **Equipment** shall be operated within the thermal rating conditions contained in the appropriate standards, specifications, and other relevant publications, taking into account the intended use. Such information will be made available by the **DNO** upon request.

(g) The standards, publications and specifications referred to in paragraphs (a) to (f) above are such standards, publications and specifications current at the time that the **Plant** and/or **Apparatus** was manufactured (and not commissioned) in the case of **Plant** and/or **Apparatus** on the **Total System**, or awaiting use or re-use. If any such **Plant/Apparatus** is subsequently moved to a new location or used in a different way, or for a different purpose, or is otherwise modified then such standards, publications and specifications current at the time that the **Plant** and/or **Apparatus** was manufactured (and not commissioned) will apply provided that in applying such standards, publications and specifications the **Plant** and/or **Apparatus** is reasonably fit for its intended purpose having due regard to the obligations of the **DNO** and the **User** under their respective licences.

(h) All **Equipment** at the **Ownership Boundary** shall meet the design principles contained above. Connections for entry to and exit from the **DNO's Distribution Network** shall incorporate a means of disconnection of the **User's** installation by the **DNO**.

9.18 **Communications and Telemetry Equipment**

Where required by the **DNO** in order to ensure control of the **DNO's Distribution Network,** communications between **Users** and the **DNO** shall be established in accordance with the following. **Users** shall provide and maintain those parts of the communications equipment within their location. Provision of any necessary communications requirements shall be in accordance with the **Connection Agreement** for a specific connection.

9.18.1 **Primary Speech Facility**

**Users** at their own cost shall provide and maintain equipment approved by the **DNO** by means of which routine and emergency communications may be established between the **User** and the **DNO**.

Connection to the **DNO's** corporate telephone network and any circuit or circuits required to connect the **Users** with the point of connections shall be provided in accordance with the **Connection Agreement.**

The facilities to be provided by the connection and the signalling and logical requirements for the interface between the **Users** equipment and the connection to the **DNO's** corporate telephone network will be specified in the **Connection Agreement.**

9.18.2 **Telemetry**

The **User** shall provide such voltage, current, frequency, **Active Power** and **Reactive Power** pulses and outputs and status points from his **System** as are considered reasonable by the **DNO** to ensure adequate **System** monitoring. The telemetry outstation in such a situation will be provided, installed and maintained by the **DNO**.

9.18.3 **Telecontrol Outstation**

If it is agreed between the parties that the **DNO** shall control the switchgear on the **User's System**, the **DNO** shall install the necessary telecontrol outstation. Notwithstanding the above, it shall be the responsibility of the **User** to provide the necessary control interface for the switchgear of the **User** which is to be controlled.

9.18.4 **Instructor Facilities**

Where required by the **DNO**, the **User** shall provide accommodation for special instructor facilities specified by **DNO** for the receipt of operational messages.

9.18.5 **Data Entry Terminals**

The **User** shall accommodate the **DNO's** data entry terminals for the purpose of information exchange.

9.18.6 **System Monitoring**

Monitoring equipment is provided on the **DNO's Distribution Network** to enable the **DNO** to monitor dynamic performance conditions. Under the requirements of the **Grid Code**, **Generation Sets** and **Power Stations** will need to provide signals for monitoring purposes. Where this monitoring equipment requires input signals from the **User's** side of the **DNO/User Ownership Boundary**, the **User** shall be responsible for the provision of suitable signals in accordance with the **Connection Agreement].**