nationalgrid

GRID CODE

CONSULTATION DOCUMENT

and REPORT TO THE AUTHORITY

Power Park Modules and

Synchronous Generating Units

The purpose of this document is to consult on the above Grid Code Modification Proposal with authorised electricity operators liable to be materially affected by the proposed changes and forms the basis of the subsequent Report to the Authority

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Prepared by	National Grid

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DISTRIBUTION

Name	Organisation
AEO's	Various
GCRP Members/Alternates	Various
Interested Parties	Various
National Grid Website	

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SUMMARY OF PROPOSALS

0.1 Consultation documents H/04 (Generic Provisions) and SA2004 (Consultation on Technical Requirements for Windfarms) amended the Grid Code to include provisions for the new generation technologies employed in renewable energy schemes.

0.2 During the intervening period, the new requirements have been successfully applied to projects across Great Britain. However, National Grid does acknowledge that a number of detailed practical issues have come to light through liaison with developers and manufacturers which, in National Grid's opinion, are best addressed through the Grid Code changes proposed in this consultation paper.

0.3 Should these proposals ultimately be approved by the Authority, National Grid believes that the following benefits will be realised:

- improved clarity of the requirements that new plant employing non-synchronous generation technologies are obliged to meet;
- refinement of the existing provisions to reflect current experience of the technical capabilities of the emerging technologies;
- introduction of generic specifications for some items of synchronous generating plant performance;
- relaxation of a number of technical requirements for emerging technologies.

0.4 A summary of the proposals is as follows:

a) Relaxation of the fault ride through requirement to allow a conditional power swing in active power recovery;
b) Introduction of additional short-circuit fault infeed and mechanical turbine data submissions;
c) The provisions for the Power Park Module (PPM) single line diagram will be amended such that the different equivalents that the User may choose to submit are specified within the Grid Code;
d) Introduction of new provisions which would allow the additional option of continuing to provide voltage control below 20% of Rated MW output;
e) CC.7.9 amended such that it claries the requirements for manned control points at PPMs in Scotland;
f) Introduction of a new Grid Code term (Power Available) and associated provisions;
g) Generic functional performance specifications to be included into the Grid Code for excitation control systems for Synchronous Generating Units and voltage control systems for PPMs;
h) Harmonisation of the point of Voltage Control and Reactive Capability across the GB Transmission System;
i) Introduction of provisions to allow for the supply of reactive power in steady state conditions within a restricted range from PPMs connected to DNO networks on which there are restrictions;
j) Amendments to the Grid Code definition of 'Power Park Module';
k) CC.A.3.4 amended such that it adopts the existing wording used in the definitions of Primary and High Frequency Response;
l) Schedule 5 amended such that the settings for rotor overspeed and underspeed are added to the list of protection settings required for Power Park Units (PPU);

m) Update to PC.3.3 and CC.3.4 (LEEMPS provisions) accordingly such that they are reflective of the proposals outlined in this Consultation Report.

0.5 In addition, it has been acknowledged that the issue regarding the applicability of technical requirements to PPM extensions would benefit from further analysis outside this consultation process, due to the complexity of issues surrounding the matter. This issue has been considered by the GCRP and added to the list of issues the GCRP will consider in the future.

A INTRODUCTION

1. Paragraph 2 of Condition C14 of the Transmission Licence granted to the National Grid Electricity Transmission plc ("National Grid") provides that National Grid shall, in consultation with authorised electricity operators liable to be materially affected thereby, periodically review the Grid Code and its implementation. That paragraph also requires National Grid, following such review, to send to the Authority:-

   (a) a report on the outcome of such review;

   (b) any proposed revisions to the Grid Code as National Grid (having regard to the outcome of such review) reasonably thinks fit for the achievement of the objectives set out in sub-paragraph (b) of Condition C14 of the Transmission Licence; and

   (c) any written representations or objections from authorised electricity operators (including any proposals by such operators for revisions to the Grid Code not accepted by National Grid in the course of the review) arising during the consultation process and subsequently maintained.

2. This review is concerned with changes to the Grid Code developed through the Power Park Modules and Synchronous Generating Units Working Group. The changes proposed will:
   - introduce improvements to existing Grid Code provisions for new generation technologies in light of experience obtained since the introduction of the H/04 (Generic Provisions) and SA2004 (Consultation on Technical Requirements for Windfarms) requirements in May 2005
   - introduce new provisions for PPMs to aid visibility and clarity of the requirements appropriate to them
   - introduce new provisions concerning the requirements of excitation systems of synchronous plant, in order to increase visibility of the requirements that will be included in Bilateral Agreements

3. The proposed changes to the Grid Code were discussed with the Grid Code Review Panel on 23rd November 2006. Panel members agreed that having taken account of comments received, National Grid should issue a Consultation Paper.

4. The revisions to the Grid Code proposed by National Grid and sent to the Authority require approval by that body and will, if approved, come into force on such date (or dates) of which you will be notified by National Grid, in accordance with the Authority's approval.

5. Comments should be sent to National Grid by **18th January 2007** as detailed below in Section C. The comments will be reviewed and responded to.

6. Unless otherwise marked as confidential any responses including those containing objections to the proposals which are maintained will be published on our website.

B. DESCRIPTION OF THE PROPOSED AMENDMENTS AND THEIR EFFECTS

8. Background

8.1 In May 2005, Ofgem approved major changes to the Grid Code resulting from consultations H/04 (Generic Provisions) and SA2004 (Consultation on Technical Requirements for Windfarms). These changes were designed to update the Grid Code to specifically include the new generation technologies employed in renewable energy schemes.

8.2 Since then, the new Grid Code requirements have been successfully applied to projects across Great Britain. However, during this period, a number of detailed practical issues have come to light through liaison with developers and manufacturers that National Grid believe are best addressed through Grid Code changes.

8.3 In November 2005, Econnect held a meeting for the BWEA (British Wind Energy Association) and project developers to discuss their experience with the Grid Code and Bilateral Agreements for connection to the Transmission System. The meeting noted two main areas of concern:

(a) The dynamic voltage performance requirements being required by National Grid in Bilateral Agreements are significantly in excess of the Grid Code.

(b) In some cases the reactive capability required on distribution connected Generators can not be used because of constraints in the Distribution Network.

8.4 In response to the issues highlighted by the BWEA, National Grid agreed to consider the inclusion into the Grid Code of the generic technical performance requirements for Voltage Control Systems for PPMs and to investigate whether Distribution Network constraints affect reactive capability requirements.

8.5 Generators have previously requested that generic performance requirements for the Excitation Control System for Synchronous Generators are included in the Grid Code. National Grid agreed to consider this proposal and believed that it would be suitable to discuss the issue at the same time as the voltage control requirements for PPMs were discussed.

8.6 The GCRP agreed at their meeting in February 2006 that a GCRP Working Group should be formed to review a number of areas identified by National Grid, the BWEA forum and Generators. This Working Group reported back its conclusions to the GCRP in November 2006 and this consultation paper seeks the views of interested parties on those conclusions.

9. Proposed Changes

9.1 National Grid believe that the proposals outlined in this report:

- will improve clarity on the requirements that new plant employing non-synchronous generation technologies are obliged to meet;
- refine existing provisions to reflect current experience of the technical capabilities of the emerging technologies;

- introduce generic specifications for some items of synchronous generating plant performance;
- constitute a number of relaxations of technical requirements for emerging technologies

9.2 The proposals may be summarised as follows:

Relaxation of Fault Ride Through Recovery Requirements

9.2.1 It is proposed to introduce additional provisions which will mean a relaxation of the current obligations by allowing subsequent oscillations in output power following a fault, provided that the integral of the Active Power output during the oscillations is at least equal to that which would have been achieved had there been no oscillations, and that the oscillations are sufficiently well damped.

Turbine Data

9.2.2 It is proposed to introduce the requirement to submit additional data that will be used by National Grid to undertake system studies. The data streams will be submitted by the developer at the time of application for a CUSC contract and will form part of the Week 24 submission where applicable.

User System Layout

9.2.3 The provisions for the PPM single line diagram, provided by Users to describe their network, will be amended such that the different equivalents that the User may choose to submit are specified within the Grid Code.

9.2.4 The requirements will be aligned with the proposed requirements for the submission of short circuit infeed data.

Short Circuit Infeed Data

9.2.5 It is recommended to introduce new provisions regarding the submission of short circuit infeed data. The data is required to make accurate assessments of short circuit levels across the Transmission System.

9.2.6 It is acknowledged that this provision constitutes a greater data requirement for PPMs compared to equivalent Synchronous Generating Units.

Voltage Control and Reactive Range Capability below 20% Active Power Output

9.2.7 It is proposed to introduce provisions that will allow an additional option of continuing to provide voltage control below 20% of Rated MW output. The proposal will provide additional flexibility for Users and will be of benefit to the Transmission and/or Distribution System to which it is connected.

9.2.8 The proposed amended provision will not specify the reactive capability required if voltage control is offered below 20% Rated MW. The existing requirements that the Generators should be able to supply zero MVArs within a tolerance will continue to apply.

Manned Control Points

9.2.9 It is proposed to amend CC.7.9 such that it clarifies the requirements for manned control points at Power Park Modules in Scotland.

9.2.10 Currently where Balancing Codes 1 and 2 apply to a BELLA (Bilateral Embedded Licence exemptable Large power station Agreement), it requires the power station to be able to respond to control instructions and therefore implies a continuously manned control point. However CC.7.9 of the Grid Code required Embedded Exemptable Large Power Stations in SHETL's area to have a manned control point between 0800 and 1800 hours only. It is this inconsistency between the CC.7.9 and BC2 provisions that will be addressed by this proposal.

Power Available Monitoring Signal

9.2.11 It is recommended to introduce a new Grid Code term ('Power Available') and associated provisions. The new term will indicate the maximum possible output of the PPM based on the turbines in service and the prevailing wind speed. The data will be used to indicate the amount of reserve currently being held by the PPM.

Excitation Control System for Synchronous Generating Units

9.2.12 It is proposed that the generic requirements for the functional performance of the excitation systems of Synchronous Generating Units will be included in the Grid Code. This will increase visibility in this area of the Grid Code.

Voltage Control Systems for Power Park Modules

9.2.13 It is proposed that the specification for Voltage Control Systems for PPMs will be included in the Grid Code. This will increase visibility of the requirements and ensure consistency.

9.2.14 The proposals will seek to remove ambiguity of interpretation that arises from the specification of the point of voltage control in CC.6.3.8(c) and to clarify that whilst the controlled point is specified, the location of voltage control system elements including any reactive compensation plant will be selectable by the User.

9.2.15 The proposals will also clarify the performance requirements of the voltage control system by specifying transient and steady state requirements.

Harmonisation of Point of Voltage Control and Point of Reactive Capability

9.2.16 The current Reactive Power capability requirements in Scotland may result in the PPM providing a capability at the HV side of a transformer that it does not own.

9.2.17 The proposals will harmonise the point of the provision of Reactive Capability and the point of Voltage Control to be the Grid Entry Point or User System Entry Point across the whole GB Transmission System.

Provision of Reactive Capability by Embedded Generators

9.2.18 It is proposed to introduce Grid Code provisions for PPMs to allow the supply of steady state reactive power within a reduced range where the generator is connected to a DNO network which has restrictions. Any limitations will be discussed and agreed between the DNO, National Grid, Generators and the relevant Transmission Owner.

9.2.19 The current provisions concerning the despatch of reactive power for Synchronous Generators (BC2.A.2.6) allow the despatch of a MVAr target that takes account of network restrictions. The provisions also allow for an agreement whereby the Generator will return to this despatch value following a system disturbance.

Definition of Power Park Modules

9.2.20 It is recommended that the existing Grid Code definition for 'Power Park Module' be amended. The amended definition will reflect the fact that synchronous plant may be used in future PPMs.

9.2.21 The proposal will remove the term 'Non-Synchronous' from the definition. The definition will still require an intermittent power source and will therefore still not apply to a conventional plant.

Frequency Response/Control

9.2.22 The existing wording in the definitions of Primary and High Frequency Response are to be adopted in CC.A.3.4 to clarify the frequency response requirements for PPMs following large frequency disturbances.

Schedule 5 Data

9.2.23 Existing Grid Code Schedule 5 will be amended such that the settings for rotor overspeed and underspeed are added to the list of protection settings required for PPUs.

Cross Referencing for Licence Exempt Embedded Medium Power Stations (LEEMPS) Provisions

9.2.24 It is important that the new provisions are adequately incorporated within the existing LEEMPS arrangements. It recommended that PC.3.3 and CC.3.4 are updated accordingly such that they reflect the proposals outlined in this Consultation Report. For these proposals to be fully effective consequential changes to the Distribution Code will be required.

10. Working Group Discussions

10.1 The rationale behind the proposals was developed through discussions in the Power Park Modules and Synchronous Generating Units Working Group. The complete record of how the change proposal was developed can be found in the Working Group Report:

https://www.nationalgrid.com/uk/Electricity/Codes/gridcode/workinggroups/ppm/

10.2 There was broad agreement amongst the Working Group members for the formal proposals summarised in Section 9 of this report. During Working Group discussions, differing views amongst members on particular aspects of the proposals were acknowledged and are summarised as follows:

Short Circuit Infeed Data

10.3 One Working Group member proposed that a subset of the full data is submitted if actual data is not available. They also propose that the main data submission should be detailed planning data and that this only needs to be submitted if National Grid identifies an issue.

10.4 The proposal to submit a subset of the full data has been included in the legal text. The requirement to always submit full data when it is available has been retained to ensure efficient investment in the transmission system. The data has been kept as standard planning data to maintain consistency with other fault data requirements.

Voltage Control and Reactive Range Capability below 20% Active Power Output

10.5 One Working Group member suggested that it may be beneficial to modify the current CC.6.3.2 provisions to reflect the revised requirements for the provision of voltage control below 20% Rated MW output.

10.6 In National Grid's opinion amending CC.6.3.2 will require the specification of a reactive power range. The aim of the proposals is to allow voltage control within any reactive range available. Therefore National Grid does not propose additional modifications to CC.6.3.2 regarding this issue.

Excitation Control System for Synchronous Generating Units

10.7 A Working Group member highlighted that some proposed modifications will not affect performance in all areas and therefore it may not be possible to meet higher performance requirements following a modification. The member suggested that Grid Code should be amended to reflect this fact.

10.8 National Grid will ensure that any requirements specified in the Bilateral Agreement will be based on existing requirements and any enhancements achievable by the modification. The Grid Code proposals are not intended to allow unachievable requirements to be specified. The Grid Code proposals allow for values to be set within a range; it will not specify default values.

10.9 A Working Group member queried a number of the clauses relating to the performance of excitation systems. The member indicates that they would prefer not to have exceptional values specified.

10.10 In National Grid's opinion the proposals reflect the wording currently used in Bilateral Agreements and to put other values in the Grid Code would not meet the objective of the changes, which is to make visible the requirements likely to be included in a Bilateral Agreement. The inclusion of exceptional values was proposed by other Working Group members.

Harmonisation of Point of Voltage Control and Point of Reactive Capability

10.11 A Working Group member indicated that the proposals would result in a reduction in the reactive capability available to the Transmission Network for some future generation connections, possibly resulting in increased TO investment requirements, the materiality of which could not be specified at this time.

10.12 National Grid believes the proposals reflect the group consensus and that they will result in a consistent approach across the GB Transmission System.

Voltage Control Systems for Power Park Modules

10.13 It was highlighted by some Working Group members that it would be beneficial for the Grid Code to explicitly state that the transient requirements can be achieved by a control scheme acting at the terminals.

10.14 It is National Grid's opinion that the Grid Code should not describe specific methods of meeting the requirements. This is a matter in which the generator is free to select any suitable arrangement.

10.15 Some Working Group members would prefer to have explicit voltage limits specified indicating where the requirements to produce maximum reactive current end.

10.16 It is National Grid's view that the need to give maximum reactive support when the connection point voltage is outside normal limits does not stop if the voltages get further from the normal range. The aim of the proposals is to ensure support is not removed as system conditions worsen.

10.17 A Working Group member would prefer if CC.A.7.2.2.5 was reworded such that the response must begin, but need not be completed, within 5 seconds.

10.18 NGET require that the response is completed within 5 seconds to ensure consistency with its licence standards.

10.19 A Working Group member highlighted that the requirement for a "linearly increasing" response does not reflect the actual performance of the likely plant operation e.g. capacitor switching.

10.20 National Grid recognises this concern but believe that it is not possible to put suitable words in the Grid Code that would describe all of the possible acceptable solutions. National Grid proposes to include examples of acceptable solutions in the associated guidance notes.

Provision of Reactive Capability by Embedded Generators

10.21 A Working Group member suggested that the Grid Code should specify that DNO restrictions will have no material impact on generators compliance with the reactive capability requirements.

10.22 It is National Grid's view that the restrictions relate to utilisation, not capability, and that it is not appropriate to modify the Grid Code. National Grid's statement that compliance will not be affected is included in the associated Working Group Report and meeting minutes.

Frequency Response/Control

10.23 It is the opinion of some Working Group members that the proposals for Frequency Response do not add any value and that further debate is required regarding this issue.

10.24 National Grid believes that the proposals add clarification to the requirements and this view is supported by some generators.

C. RESPONSES

11. This section will contain a summary of responses received during the Consultation and will be completed as part of the Report to the Authority.

12. Views are invited upon the proposals outlined in this report. Detailed legal text to give effect to the proposed changes may be found in Appendix A.

13. Your formal responses may be:-

Posted to: Lilian Macleod
Electricity Codes
Commercial Frameworks
National Grid Electricity Transmission plc
National Grid House
Warwick Technology Park
Gallows Hill
Warwick, CV34 6DA

Emailed to: lilian.macleod@uk.ngrid.com

APPENDIX A: PROPOSED REVISIONS TO THE GRID CODE

The following extract shows the proposed changes to the Planning Code to include the additional data items.

PC.A.5.4.2. …….

(b) **Power Park Unit** parameters

* Rated MVA
* **Rated MW**
* Rated terminal voltage
* ~~Inertia constant (MWsec/MVA) at synchronous speed~~

Average site air density (kg/m^3), maximum site air density (kg/m^3) and minimum site air density (kg/m^3) for the year

Year for which air density data is submitted

Number of pole pairs

Blade swept area (m^2)

Gear box ratio

Mechanical drive train

For each **Power Park Unit**, details of the parameters of the drive train represented as an equivalent two mass model should be provided. This model should accurately represent the behaviour of the complete drive train for the purposes of power system analysis studies and should include the following data items:-

Equivalent i~~I~~nertia constant (MWsec/MVA) of the first mass (eg. wind turbine rotor and blades) at minimum, synchronous and rated speeds

Equivalent ~~I~~inertia constant (MWsec/MVA) of the second mass (eg. generator rotor) at minimum, synchronous and rated speeds

Equivalent s~~S~~haft stiffness between the two masses (Nm/electrical radian)

Additionally, for **Power Park Units** that are ~~squirrel-cage or doubly-fed~~ induction generators (eg. squirrel cage, doubly-fed) driven by wind turbines:

* Stator resistance
* Stator reactance
* Magnetising reactance.
* Rotor resistance (at starting)
* Rotor resistance (at rated running)
* Rotor reactance (at starting)
* Rotor reactance (at rated running)

Additionally for doubly-fed induction generators only:

The generator rotor speed range (minimum and maximum speeds in RPM)

The optimum generator rotor speed versus wind speed submitted in tabular format

Power converter rating (MVA)

………

Transfer function block diagram, including parameters and description of the operation of the power electronic converter and fault ride through capability (where applicable).

…….

The corresponding changes are required in the DRC Schedule 1 Data table as shown below:

Schedule 1
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DATA DESCRIPTION	UNITS	DATA CAT.	POWER PARK UNIT (OR POWER PARK MODULE, AS THE CASE MAY BE)						
			G1	G2	G3	G4	G5	G6	STN
Power Park Module Rated MVA	MVA	**SPD+**							
Power Park Module Rated MW	MW	**SPD+**							
*Performance Chart of a ~~at~~ **Power Park Module** at the connection point		**SPD**	(see **OC2** for specification)						
***Output Usable** (on a monthly basis)	MW	**SPD**	(except in relation to **CCGT Modules** when required on a unit basis under the **Grid Code,** this data item may be supplied under Schedule 3)						
Number & Type of **Power Park Units** within each **Power Park Module**									
Power Park Unit Model - A validated mathematical model in accordance with PC.5.4.2 (a)	Transfer function block diagram and algebraic equations, simulation and measured test results	**DPD**							
Power Park Unit Data (where applicable)									
Rated MVA	MVA	**SPD+**							
Rated MW	MW	**SPD+**							
Rated terminal voltage	V	**SPD+**							
~~Inertia constant at synchronous speed~~	~~MW secs /MVA~~	~~**SPD+**~~							
Site minimum air density	kg/m^3	**SPD+**							
Site maximum air density	kg/m^3	**SPD+**							
Site average air density	kg/m^3	**SPD+**							
Year for which air density data is submitted		**SPD+**							
Number of pole pairs		**DPD**							
Blade swept area	m^2	**DPD**							
Gear box ratio		**DPD**							
Stator Resistance.	% on MVA	~~**DPD**~~ **SPD+**							
Stator Reactance.	% on MVA	**SPD+**							
Magnetising Reactance	% on MVA	**SPD+**							
Rotor Resistance (at starting).	% on MVA	**DPD**							
Rotor Resistance (at rated running)	% on MVA	**SPD+**							
Rotor Reactance (at starting).	% on MVA	**DPD**							
Rotor Reactance (at rated running)	% on MVA	**SPD**							
Equivalent i~~I~~nertia constant of the first mass (eg. wind turbine rotor and blades) at minimum speed	MW ~~secs~~ /MVA	~~**DPD**~~ **SPD+**							
Equivalent ~~I~~inertia constant of the first mass (eg. wind	MW ~~secs~~	~~**DPD**~~							

DATA DESCRIPTION	UNITS	DATA CAT.	POWER PARK UNIT (OR POWER PARK MODULE, AS THE CASE MAY BE)						
			G1	G2	G3	G4	G5	G6	STN
turbine rotor and blades) at synchronous speed	/MVA	SPD+							
Equivalent iInertia constant of the first mass (eg. wind turbine rotor and blades) at rated speed	MW secs /MVA	DPD SPD+							
Equivalent iInertia constant of the second mass (eg. generator rotor) at minimum speed	MW secs /MVA	DPD SPD+							
Equivalent Iinertia constant of the second mass (eg. generator rotor) at synchronous speed	MW secs /MVA	DPD SPD+							
Equivalent iInertia constant of the second mass (eg. generator rotor) at rated speed	MW secs /MVA	DPD SPD+							
Equivalent sShaft stiffness between the two masses	Nm / electrical radian	DPD SPD+							

Schedule 1
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DATA DESCRIPTION	UNITS	DATA CAT.	POWER PARK UNIT (OR POWER PARK MODULE, AS THE CASE MAY BE)						
			G1	G2	G3	G4	G5	G6	STN
………									
Transfer function block diagram, parameters and description of the operation of the power electronic converter including fault ride through capability (where applicable).	Diagram	**DPD**							

Glossary and Definitions

Common Collection Busbar

A busbar within a **Power Park Module** to which the higher voltage side of two or more **Power Park Unit** generator transformers are connected.

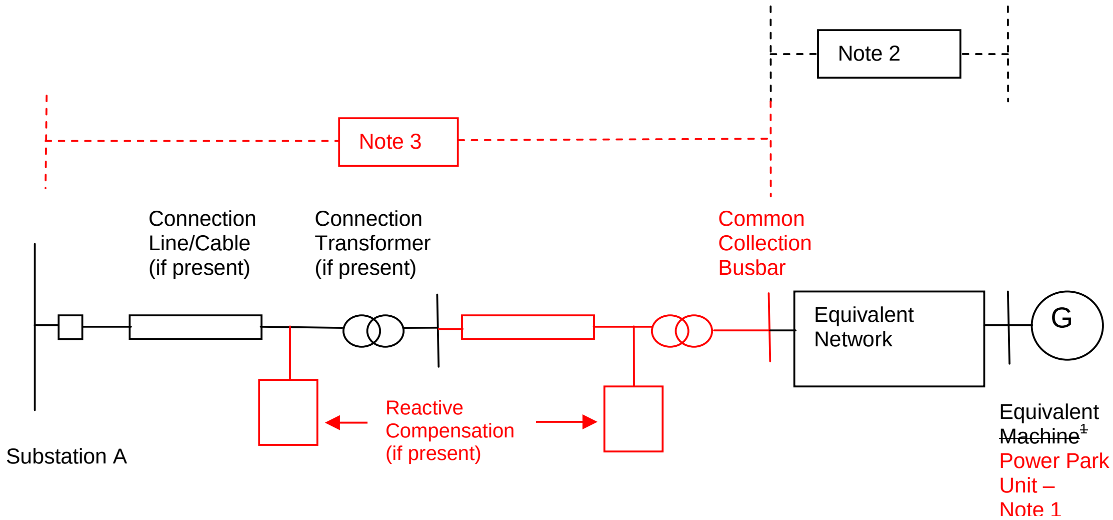
User's System Layout

PC.A.2.2.2 ….

The **Single Line Diagram** for a **Power Park Module** must include all parts of the System connecting generating equipment to the **Grid Entry Point** (or (**User System Entry Point** if **Embedded**). As an alternative the **User** may choose to submit a **Single Line Diagram** with the equipment between the equivalent **Power Park Unit** and the **Common Collection Busbar** reduced to an electrically equivalent network.~~**of** an electrically equivalent system connecting generating equipment to the **Grid Entry Point** (or **User System Entry Point** if **Embedded**). An example of~~ The format for a **Single Line Diagram** for a **Power Park Module** electrically equivalent system is shown in Appendix B.

PLANNING CODE APPENDIX B

Power Park Module Single Line Diagram



Notes:

1) ~~It is recommended that this~~ The electrically equivalent **Power Park Unit** consists of 'N' actual ~~generators~~ **Power Park Units** of the same type ie. any equipment external to the ~~generator~~ **Power Park Unit** terminals is considered as part of the Equivalent Network. **Power Park Units** of different types shall be included in separate electrically equivalent **Power Park Units**. The total number of equivalent **Power Park Units** shall represent all of the actual **Power Park Units** in the **Power Park Module**.
2) ~~Where a Power Park Module consists of different Power Park Units, the equivalent machine and network can be repeated for each different unit~~Separate electrically equivalent networks are required for each electrically equivalent **Power Park Unit**. The electrically equivalent network shall include all equipment between the **Power Park Unit** terminals and the **Common Collection Busbar**.
3) All **Plant** and **Apparatus** including the circuit breakers, transformers, lines, cables and reactive compensation plant between the **Common Collection Busbar** and Substation A shall be shown.

Short Circuit Contribution to GB Transmission System

PC.A.2.5.5.2 Auxiliary motor short circuit current contribution and any **Auxiliary Gas Turbine Unit** contribution through the **Unit Transformers** must be represented as a combined short circuit current contribution at the **Generating Unit's** terminals, assuming a fault at that location. ~~In the case of a **Power Park Unit** in a **Power Park Module**, the combined short circuit contribution need only be provided for each type of **Power Park Unit** in the **Power Park Module**.~~

PC.A.2.5.5.7 For each **Power Park Module** and each type of **Power Park Unit** (eg. Doubly Fed Induction Generator), including any **Auxiliaries**, positive, negative and zero sequence root mean square current values are to be provided of the contribution to the short circuit current flowing at

(i) the **Power Park Unit** terminals, or the **Common Collection Busbar** if an equivalent **Single Line Diagram** and associated data as described in PC.A.2.2.2 is provided, and
(ii) the **Grid Entry Point**, or **User System Entry Point** if **Embedded**

for the following solid faults at the **Grid Entry Point**, or **User System Entry Point** if **Embedded**:.

(i) a symmetrical three phase short circuit
(ii) a single phase to earth short circuit
(iii) a phase to phase short circuit
(iv) a two phase to earth short circuit

For a **Power Park Module** in which one or more of the **Power Park Units** utilise a protective control such as a crowbar circuit, the data should indicate whether the protective control will act in each of the above cases and the effects of its action shall be included in the data. For any case in which the protective control will act, the data for the fault shall also be submitted for the limiting case in which the protective circuit will not act, which may involve the application of a non-solid fault, and the positive, negative and zero sequence retained voltages at

(i) the **Power Park Unit** terminals, or the **Common Collection Busbar** if an equivalent **Single Line Diagram** and associated data is provided and
(ii) the **Grid Entry Point**, or **User System Entry Point** if **Embedded**

in this limiting case shall be provided.

For each fault for which data is submitted, the data items listed under the following parts of PC.A.2.5.6(a) shall be provided:-

(iv), (vii), (viii), (ix), (x);

In addition, if an equivalent **Single Line Diagram** has been provided the data items listed under the following parts of PC.A.2.5.6(a) shall be provided:-

(xi), (xii), (xiii);

In addition, for a **Power Park Module** in which one or more of the **Power Park Units** utilise a protective control such as a crowbar circuit:-

the data items listed under the following parts of P.C.A.2.5.6(a) shall be provided:-

(xiv), (xv);

All of the above data items shall be provided in accordance with the detailed provisions of PC.A.2.5.6(c), (d), (f).

Variation of Infeed during Faults

PC.A.2.5.6 Data Items

(a) The following is the list of data utilised in this part of the **PC**. It also contains rules on the data which generally apply:-

(vii) A continuous trace and a table showing the root mean square of the positive, negative and zero sequence components of the short circuit current between zero and 140ms at 10ms intervals.

(viii) The MWs being generated pre-fault by the **Power Park Module** and by each type of **Power Park Unit**

(ix) The reactive compensation shown explicitly on the **Single Line Diagram** that is switched in

(x) The **Power Factor** of the **Power Park Module** and of each **Power Park Unit** type

(xi) The positive sequence X/R ratio of the equivalent at the **Common Collection Busbar**

(xii) The minimum zero sequence impedance of the equivalent seen from the **Common Collection Busbar**

(xiii) The number of **Power Park Units** represented in the equivalent **Power Park Unit**

(xiv) The additional rotor resistance and reactance (if any) that is applied to the **Power Park Unit** under a fault condition

(xv) A continuous trace and a table showing the root mean square of the positive, negative and zero sequence components of the retained voltage at the fault point and **Power Park Unit** terminals, or the **Common Collection Busbar** if an equivalent **Single Line Diagram** and associated data as described in **PC.A.2.2.2** is provided, representing the limiting case, which may involve the application of a non-solid fault, required to not cause operation of the protective control

The information requested by the Planning Code is submitted by Users on the schedules contained in the Data Registration Code. National Grid proposes to add a third sheet to Schedule 14 to cover the Planning Code Changes relating to fault infeed data for Power Park Units.

SCHEDULE 14
Page 3 of 3

Fault infeeds from **Power Park Modules**

A submission is required for the whole **Power Park Module** and for each **Power Park Unit** type or equivalent. The submission shall represent operating conditions that result in the maximum fault infeed. The fault current from all motors normally connected to the **Power Park Unit's electrical system** shall be included. The fault infeed shall be expressed as a fault current at the terminals of the **Power Park Unit,** or the **Common Collection Busbar** if an equivalent **Single Line Diagram** and associated data as described in PC.A.2.2.2 is provided, and the **Grid Entry Point**, or **User System Entry Point** if **Embedded**, for a fault at the **Grid Entry Point**, or **User System Entry Point** if **Embedded**.

Should actual data in respect of fault infeeds be unavailable at the time of the application for a **CUSC Contract**, a limited subset of the data, representing the maximum fault infeed that may result from all of the plant types being considered, shall be submitted. This data will, as a minimum, include the continuous time trace and table showing the root mean square of the positive, negative and zero sequence components of the fault current for both single phase and three phase solid faults at the **Grid Entry Point** (or **User System Entry Point** if **Embedded**). Actual data in respect of fault infeeds shall be submitted to **NGET** as soon as it is available, in line with PC.A.1.2.

DATA DESCRIPTION	UNITS	F.Yr. 0	F.Yr. 1	F.Yr. 2	F.Yr. 3	F.Yr. 4	F.Yr. 5	F.Yr. 6	F.Yr. 7
Name of **Power Station**									
Name of **Power Park Module**									
Power Park Unit type									
A submission shall be provided for the contribution of the entire **Power Park Module** and each type of **Power Park Unit** or equivalent to the positive, negative and zero sequence components of the short circuit current at the **Power Park Unit** terminals, or **Common Collection Busbar**, and **Grid Entry Point** or **User System Entry Point** if **Embedded** for (i) a solid symmetrical three phase short circuit (ii) a solid single phase to earth short circuit (iii) a solid phase to phase short circuit (iv) a solid two phase to earth short circuit at the **Grid Entry Point** or **User System Entry Point** if **Embedded.** If protective controls are used and active for the above conditions, a submission shall be provided in the limiting case where the protective control is not active. This case may require application of a non-solid fault, resulting in a retained voltage at the fault point.									
- A continuous time trace and table showing the root mean square of the positive, negative and zero sequence components of the fault current from the time of fault inception to 140ms after fault inception at 10ms intervals	Graphical and tabular kA versus s								
- A continuous time trace and table showing the positive, negative and zero sequence components of retained voltage at the terminals or **Common Collection Busbar**, if appropriate	p.u. versus s								
- A continuous time trace	p.u.								

and table showing the root mean square of the positive, negative and zero sequence components of retained voltage at the fault point, if appropriate	versus s									
For **Power Park Units** that utilise a protective control, such as a crowbar circuit,										
- additional rotor resistance applied to the **Power Park Unit** under a fault situation	% on MVA									
- additional rotor reactance applied to the **Power Park Unit** under a fault situation.	% on MVA									
Positive sequence X/R ratio of the equivalent at time of fault at the **Common Collection Busbar**										
Minimum zero sequence impedance of the equivalent at **Common Collection Busbar**										
MW generated pre-fault	MW									
Number of **Power Park Units** in equivalent generator										
Power Factor (lead or lag)										
Pre-fault voltage (if different from 1.0 p.u.) at fault point (See note 1)	p.u.									
Items of reactive compensation switched in pre-fault										

Note 1. The pre-fault voltage provided above should represent the voltage within the range 0.95 to 1.05 that gives the highest fault current

Extension of a Power Park Module

CC.6.3 GENERAL **GENERATING UNIT** REQUIREMENTS

CC.6.3.1 This section sets out the technical and design criteria and performance requirements for **Generating Units, DC Converters** and **Power Park Modules** (whether directly connected to the **GB Transmission System** or **Embedded**) which each **Generator** or **DC Converter Station** owner must ensure are complied with in relation to its **Generating Units**, **DC Converters** and **Power Park Modules** but does not apply to **Small Power Stations** or individually to **Power Park Units**. References to **Generating Units, DC Converters** and **Power Park Modules** in this CC.6.3 should be read accordingly.

Voltage Control and Reactive Range Reactive Range below 20% Power Output

CC6.3.8 ……….

(c) In the case of a **Non-synchronous Generating Unit, DC Converter** or **Power Park Module** a continuously-acting automatic control system is required to provide control of the voltage (or zero transfer of **Reactive Power** as applicable to CC.6.3.2) at the **Grid Entry Point** or **User System Entry Point** without instability over the entire operating range of the **Non-Synchronous Generating Unit, DC Converter** or **Power Park Module**. In the case of a **Power Park Module** in Scotland, voltage control may be at the **Power Park Unit** terminals, an appropriate intermediate busbar or the **Connection Point** as specified in the **Bilateral Agreement**. When operating below 20% **Rated MW** the automatic control system may continue to provide voltage control utilising any available reactive capability. If voltage control is not being provided, ~~T~~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 1 of CC6.3.2 (c). The performance requirements for this automatic control system will be specified in the **Bilateral Agreement**.

Notes:
this change interacts with the proposed drafting for voltage control

Harmonisation of point of voltage control and point of reactive capability requirement

The revised drafting for CC.6.3.2(c) is shown below.

CC.6.3.2 …….

(c) Subject to the provisions of CC.6.3.2(d) below, all **Non-Synchronous Generating Units, DC Converters** (excluding current source technology) and **Power Park Modules** (excluding those connected to the **Total System** by a current source **DC Converter**) with a **Completion Date** on or after 1 January 2006 must be capable of supplying **Rated MW** output at any point between the limits 0.95 **Power Factor** lagging and 0.95 **Power Factor** leading at the **Grid Entry Point** (or **User System Entry Point** if **Embedded**)**.** ~~in England and Wales or at the HV side of the 33/132kV or 33/275kV or 33/400kV transformer for **Generators** directly connected to the **GB Transmission System** in Scotland (or **User System Entry Point** if **Embedded**)~~. With all **Plant** in service, the **Reactive Power** limits defined at **Rated MW** at Lagging **Power Factor** will apply at all **Active Power** output levels above 20% of the **Rated MW** output as defined in Figure 1. With all **Plant** in service, the **Reactive Power** limits defined at **Rated MW** at Leading **Power Factor** will apply at all **Active Power** output levels above 50% of the **Rated MW** output as defined in Figure 1. With all **Plant** in service, the **Reactive Power** limits will reduce linearly below 50% **Active Power** output as shown in Figure 1 unless the requirement to maintain the **Reactive Power** limits defined at **Rated MW** at Leading **Power Factor** 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.

The revised drafting for the Glossary and Definitions, CC.6.3.8, BCA2.A.2.5 and BC2.A.2.6 plus an additional appendix, APPENDIX 6, is shown below.

Glossary and Definitions

Automatic Voltage Regulator or **AVR**	~~A continuously acting automatic excitation system to control a **Generating Unit** terminal voltage.~~ The continuously acting automatic equipment controlling the terminal voltage of a **Synchronous Generating Unit** by comparing the actual terminal voltage with a reference value and controlling by appropriate means the output of an **Exciter**, depending on the deviations
Setpoint Voltage	The voltage at the **Grid Entry Point**, or **User System Entry Point** if **Embedded**, at which the transfer of **Reactive Power** between a **Power Park Module**, **DC Converter** or **Non-Synchronous Generating Unit** and the **Transmission System,** or **Network Operator's** system if **Embedded**, is zero.

CC6.3.8 ……….

(b) In respect of **Synchronous Generating Units** with a **Completion Date** before 1 January 2007, ~~T~~the requirements for excitation control facilities, including **Power System Stabilisers**, where in **NGET's** view these are necessary for system reasons, will be specified in the **Bilateral Agreement**. The performance requirements for a continuously acting automatic excitation control system that shall be complied with by the **User** in respect of **Synchronous Generating Units** with a **Completion Date** on or after 1 January 2007, or subject to a **Modification** to the continuously acting automatic excitation control system on or after 1 January 2007, are given or referred to in CC.A.6. Reference is made to on-load commissioning witnessed by **NGET** in BC2.11.2.

(c) In the case of a **Non-synchronous Generating Unit, DC Converter** or **Power Park Module** a continuously-acting automatic control system is required to provide control of the voltage (or zero transfer of **Reactive Power** as applicable to CC.6.3.2) at the **Grid Entry Point** or **User System Entry Point** without instability over the entire operating range of the **Non-Synchronous Generating Unit, DC Converter** or **Power Park Module**. Any **Plant** or **Apparatus** used in the provision 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**. In the case of a **Power Park Module** in Scotland with a **Completion Date** before 1 January 2007, voltage control may be at the **Power Park Unit** terminals, an appropriate intermediate busbar or the **Connection Point** as specified in the

Bilateral Agreement. When operating below 20% **Rated MW** the automatic control system may continue to provide voltage control utilising any available reactive capability. If voltage control is not being provided, tThe 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 1 of CC6.3.2 (c). The performance requirements for this automatic control system will be specified in the **Bilateral Agreement**.

(d) The performance requirements for a continuously acting automatic voltage control system in respect of **Power Park Modules**, **Non-Synchronous Generating Units** and **DC Converters** with a **Completion Date** before 1 January 2007 will be specified in the **Bilateral Agreement**. The performance requirements for a continuously acting automatic voltage control system that shall be complied with by the **User** in respect of **Power Park Modules**, **Non-Synchronous Generating Units** and **DC Converters** with a **Completion Date** on or after 1 January 2007, or subject to a **Modification** to the continuously acting automatic voltage control system on or after 1 January 2007, are given or referred to in CC.A.7.

(ed)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 recorded in the **Bilateral Agreement** records otherwise. Operation of such control facilities will be in accordance with the provisions contained in **BC2**.

APPENDIX 6

PERFORMANCE REQUIREMENTS FOR CONTINUOUSLY ACTING AUTOMATIC EXCITATION CONTROL SYSTEMS FOR **SYNCHRONOUS GENERATING UNITS**

CC.A.6.1 Scope

CC.A.6.1.1 This Appendix sets out the performance requirements of continuously acting automatic excitation control systems for **Synchronous Generating Units** 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.

CC.A.6.1.2 Where the requirements may vary between **Bilateral Agreements** 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** reserves the right to 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**.

CC.A.6.1.3 Proposals by **Generators** to make a change to the excitation 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**.

CC.A.6.2 Requirements

CC.A.6.2.1 The **Excitation System** of a **Synchronous Generating Unit** 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 The continuously acting automatic excitation control system shall include a **Power System Stabiliser (PSS)** as a means of supplementary control. For the avoidance of doubt this applies to replacement excitation systems fitted to existing **Generating Units** during the life-time of the **Power Station** as well as new **Generating Units**. The functional specification of the **Power System Stabiliser** is included in CC.A.6.2.5.

CC.A.6.2.3 Steady State Voltage Control

CC.A.6.2.3.1 An accurate steady state control of the **Generating Unit** pre-set 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 **Generating Unit** output is gradually changed from zero to rated MVA output at rated voltage, **Active Power** and **Frequency**.

CC.A.6.2.4 Transient Voltage Control

CC.A.6.2.4.1 For a step change from 90% to 100% of the nominal **Generating Unit** terminal voltage, with the **Generating Unit** on open circuit, the **Excitation System** response shall have a damped oscillatory characteristic. For this characteristic, the time for the **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.

CC.A.6.2.4.2 To ensure that adequate synchronising power is maintained, when the **Generating Unit** is subjected to a large voltage disturbance, the **Exciter** whose output is varied by the **Automatic Voltage Regulator** shall be capable of providing its upper and lower limit ceiling voltages to the **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.

CC.A.6.2.4.3 The **Exciter** shall be capable of attaining an on-load ceiling field 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 **Generating Unit** terminals. **NGET** reserves the right to specify a value outside the above limits where **NGET** identifies a system need.

CC.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** that will be

not less than 1.6 pu
normally not greater than 2 pu
exceptionally up to 3 pu

of **Rated Field Voltage** after the removal of the step disturbance of CC.A.6.2.4.3. **NGET** reserves the right to 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 **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 a value specified in the **Bilateral Agreement** that will be

not less than 1.6 pu
normally not greater than 2 pu
exceptionally up to 3 pu

of **Rated Field Voltage** upon recovery of the **Generating Unit** terminal voltage to 80% of rated terminal voltage following fault clearance. **NGET** reserves the right to 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 included in the **Bilateral Agreement** if **NGET** identifies a **Transmission System** need.

CC.A.6.2.5 Power Oscillations Damping Control

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

CC.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.

CC.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 generator electrical power output and not the steady state level of power output.

CC.A.6.2.5.4 The output signal from the **Power System Stabiliser** shall be limited to not more than 10% of the **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.

CC.A.6.2.5.5 The **Power System Stabiliser** shall include elements which provide a limited bandwidth 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.

CC.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 commissioning the **Generator** will provide to **NGET** a report containing:

i. the **Excitation System** model including the **Power System Stabiliser** with settings as required under the **Planning Code** (PC.A.5.3.2(c)).

ii. on load time series simulations of the response of the **Excitation System** with and without the **Power System Stabiliser** to 2% and 10% steps in the reference voltage and a three phase short circuit fault apllied to the higher voltage side of the **Generating Unit** transformer for 100 ms. The results should show field voltage, **Generating Unit** terminal voltage, **Power System Stabiliser** output and **Generating Unit Active Power** and **Reactive Power** output.

iii. gain and phase Bode diagrams for the open loop frequency domain response of the **Generating Unit Excitation System** with and without the **Power System Stabiliser**, operating under maximum leading conditions and minimum fault level conditions as agreed with **NGET**. These should be in a format to allow assessment of the phase contribution of the **Power System Stabiliser** and the gain and phase margin of the **Excitation System** with the **Power System Stabiliser**

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

CC.A.6.2.6.1 The overall **Excitation System** shall include elements which provide a limited bandwidth output. 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.

CC.A.6.2.6.2 As a measure of the ability of the overall **Excitation System** to provide adequate damping, the **Automatic Voltage Regulator** shall be arranged initially to respond to step signal disturbances injected into its reference voltage level. With the **Generating Unit** operating on no load at rated voltage and disconnected from the network, small step signal disturbances into the **Automatic Voltage Regulator** shall demonstrate that the generator terminal voltage is well damped. The step signal disturbances shall not exceed 5%. For this step change the time for the **Generating Unit** voltage to first reach 100% shall be less than 0.4 seconds and the settling time to within ±5% of the voltage change shall be less than 1.6 seconds.

CC.A.6.2.6.3 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 with the **Generating Unit** 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.

CC.A.6.2.6.4 The frequency domain tuning of the **Power System Stabiliser** shall also be demonstrated by injecting a 200mHz-3Hz band limited random noise signal into the **Automatic Voltage Regulator** reference with the **Generating Unit** operating at points specified by **NGET** (up to rated MVA output). 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.

CC.A.6.2.7 **Under-Excitation Limiter** Units

CC.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 during automatic control. The **Under**

Excitation Limiter shall respond to changes in the **Active Power** (MW) and 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 rated load at any setting and shall be readily adjustable.

CC.A.6.2.7.2 The performance of the **Under Excitation Limiter** shall be independent of the rate of change of the **Generating Unit** load and shall be demonstrated by testing its response to a step change corresponding to a 2% decrease in **Automatic Voltage Regulator** reference voltage when the generator is operating just off the limit line, as set up. The resulting maximum overshoot shall not exceed 4% of the **Generating Unit** rated MVA. The operating point of the **Generating Unit** 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 **Generating Unit** MVA rating within a period of 5 seconds.

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

CC.A.6.2.8 **Over-Excitation Limiter** Units

CC.A.6.2.8.1 The settings of the **Over-Excitation Limiter** shall ensure that the generator excitation is not limited to less than the maximum value that can be achieved whilst ensuring the **Generating Unit** is operating within its design limits. If the generator 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 **Generating Unit**.

CC.A.6.2.8.2 The performance of the **Over-Excitation Limiter** shall be demonstrated by testing its response to a step change corresponding to a 2% increase in the **Automatic Voltage Regulator** reference voltage when the **Generating Unit** is operating just off the **Over-Excitation Limit**. The resulting operation beyond the **Over-Excitation Limit** shall be controlled by the **Over-Excitation Limiter** without the operation of any protection that could trip the **Generating Unit**.

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

APPENDIX 7

PERFORMANCE REQUIREMENTS FOR CONTINUOUSLY ACTING AUTOMATIC VOLTAGE CONTROL SYSTEMS FOR **NON-SYNCHRONOUS GENERATING UNITS**, **DC CONVERTERS** AND **POWER PARK MODULES**

CC.A.7.1 SCOPE

CC.A.7.1.1 This Appendix sets out the performance requirements of continuously acting automatic voltage control systems for **Non-Synchronous Generating Units**, **DC Converters** and **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.

CC.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**.

CC.A.7.2 Requirements

CC.A.7.2.1 **NGET** requires that the continuously acting automatic voltage control system for the **Non-Synchronous Generating Unit**, **DC Converter** or **Power Park Module** shall meet the following functional performance specification. If a **Network Operator** has confirmed to **NGET** that its network to which an **Embedded Non-Synchronous Generating Unit**, **DC Converter** or **Power Park Module** is connected is restricted such that the full reactive range under the steady state voltage control requirements (**CC.A.7.2.2**) cannot be utilised, **NGET** may specify alternative limits to the steady state voltage control range reflecting the restrictions in the **Bilateral Agreement**. 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.

CC.A.7.2.2 Steady State Voltage Control

CC.A.7.2.2.1 The **Non-Synchronous Generating Unit**, **DC Converter** or **Power Park Module** shall provide continuous steady state control of the voltage at the **Grid Entry Point** (or **User System Entry Point** if **Embedded**) with a **Setpoint Voltage** and **Slope** characteristic as illustrated in Figure CC.A.7.2.2a.

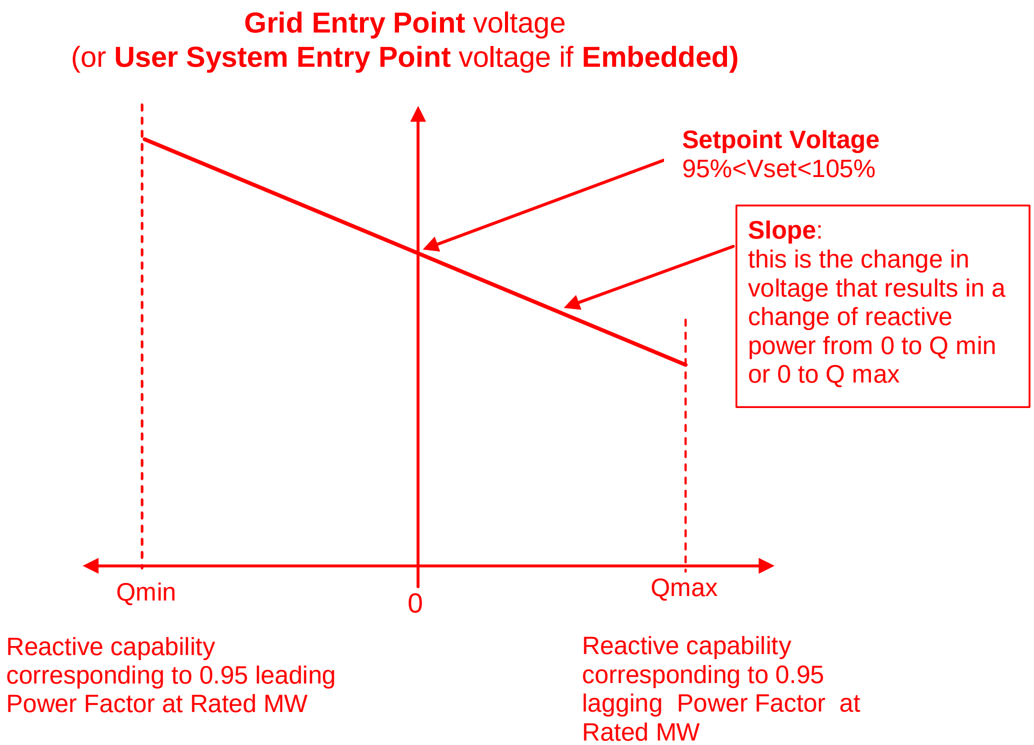


Figure CC.A.7.2.2a

CC.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%. The initial **Setpoint Voltage** will be 100%. **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 CC.6.3.4.

CC.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%). The initial **Slope** setting will be 4%. **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 CC.6.3.4.

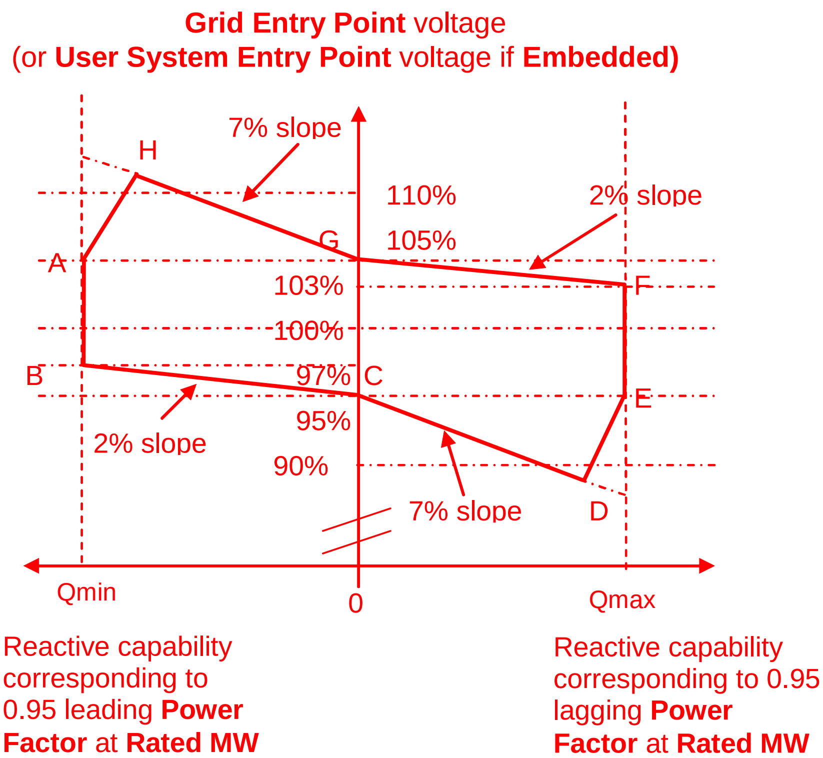


Figure CC.A.7.2.2b

CC.A.7.2.2.4 Figure CC.A.7.2.2b shows the required envelope of operation. The enclosed area within points ABCDEFGH is the required capability range of the **Non-Synchronous Generating Unit**, **DC Converter** or **Power Park Module** within which the **Slope** and **Setpoint Voltage** can be changed.

CC.A.7.2.2.5 Should the operating point of the **Non-Synchronous Generating Unit**, **DC Converter** or **Power Park Module** deviate so that it is no longer a point on the operating characteristic (figure CC.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.

CC.A.7.2.2.6 Should the **Reactive Power** output of the **Non-Synchronous Generating Unit**, **DC Converter** or **Power Park Module** reach its maximum lagging limit at a **Grid Entry Point** voltage (or **User System Entry Point** voltage if **Embedded**) above 95%, the **Non-Synchronous Generating Unit**, **DC Converter** or **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 CC.A.7.2.2b. Should the **Reactive Power** output of the **Non-Synchronous Generating Unit**, **DC Converter** or **Power Park Module** reach its maximum leading limit at a **Grid Entry Point** voltage (or **User System Entry Point** voltage if **Embedded**) below 105%, the **Non-Synchronous Generating Unit**, **DC Converter** or **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 figure CC.A.7.2.2b.

CC.A.7.2.2.7 For **Grid Entry Point** voltages (or **User System Entry Point** voltages if **Embedded**) below 95%, the lagging **Reactive Power** capability of the **Non-Synchronous**

Generating Unit, **DC Converter** or **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 figure CC.A.7.2.2b.For **Grid Entry Point** voltages (or **User System Entry Point** voltages if **Embedded**) above 105%, the leading **Reactive Power** capability of the **Non-Synchronous Generating Unit**, **DC Converter** or **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 figure CC.A.7.2.2b. Should the **Reactive Power** output of the **Non-Synchronous Generating Unit**, **DC Converter** or **Power Park Module** reach its maximum lagging limit at a **Grid Entry Point** voltage (or **User System Entry Point** voltage if **Embedded**) below 95%, the **Non-Synchronous Generating Unit**, **DC Converter** or **Power Park Module** shall maintain maximum lagging reactive current output for further voltage decreases. Should the **Reactive Power** output of the **Non-Synchronous Generating Unit**, **DC Converter** or **Power Park Module** reach its maximum leading limit at a **Grid Entry Point** voltage (or **User System Entry Point** voltage if **Embedded**) above 105%, the **Non-Synchronous Generating Unit**, **DC Converter** or **Power Park Module** shall maintain maximum leading **Reactive Power** output for further voltage increases.

CC.A.7.2.3 Transient Voltage Control

CC.A.7.2.3.1 For a step change in **Grid Entry Point** or **User System Entry Point** voltage, the continuously acting automatic control system shall respond according to the following minimum criteria

i. the **Reactive Power** output of the **Non-Synchronous Generating Unit**, **DC Converter** or **Power Park Module** shall change linearly with time. The response should commence within 0.2 seconds of the application of the step.
ii. the response rate shall be such that, for a sufficiently large step, 90% of the full reactive capability of the **Non-Synchronous Generating Unit**, **DC Converter** or **Power Park Module**, as required by **CC.6.3.2**, will be produced within 1 second
iii. the magnitude of the change in the **Reactive Power** produced within 1 second shall vary linearly in proportion to the magnitude of the step change
iv. the settling time shall be no greater than 2 seconds from the application of the step change in voltage and the peak to peak magnitude of any oscillations shall be less than 5% of the change in steady state **Reactive Power** within this time.
v. following the transient response, the conditions of CC.7.2.2.5 apply

This on load requirement shall apply irrespective of the magnitude of the step change or disturbance.

CC.A.7.2.4 Power Oscillation Damping

CC.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 **BC.2.11.2**.

CC.A.7.2.5 Overall Voltage Control System Characteristics

CC.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 **Grid Entry Point** voltage (or **User System Entry Point** voltage if **Embedded**).

CC.A.7.2.5.2 The overall voltage control system shall include elements which provide a limited bandwidth output. 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 **Non-Synchronous Generating Unit**, **DC Converter** or **Power Park Module** should also meet this requirement

CC.A.7.2.5.3 The response of the voltage control system (including the **Power System Stabiliser** if employed) shall be demonstrated by applying suitable step disturbances into the voltage control system of the **Power Park Module** or **Power Park Unit**, or by changing the actual voltage at a suitable point, with the generator 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 2 seconds of the application of the step.

BC2.A.2.5 ....

(b) **Ancillary Service** instructions for **Reactive Power** will normally follow the form:

(i) an exchange of operator names;
(ii) **BM Unit** Name;
(iii) Time of instruction;
(iv) Type of instruction (MVAR, VOLT, SETPOINT, SLOPE or TAPP)
(v) Target Value
(vi) Target Time.

The times required in the instruction are expressed as London time.

For example, for **BM Unit** ABCD-1 instructed at 1400 hours to provide 100Mvar by 1415 hours:

"**BM Unit** ABCD-1 message timed at 1400 hours. MVAR instruction. Unit to plus 100 Mvar target time 1415 hours."

BC2.A.2.6 **Reactive Power**

As described in BC2.A.2.4 and BC2.A.2.5 instructions for **Ancillary Services** relating to **Reactive Power** may consist of any of several specific types of instruction. The following table describes these instructions in more detail:

Instruction Name	Description	Type of Instruction
Mvar Output	The individual Mvar output from the **Genset** onto the **GB Transmission System** at the **Grid Entry Point** (or onto the **User System** at the **User System Entry Point** in the case of **Embedded Power Stations**), namely on the higher voltage side of the generator step-up transformer. In relation to each **Genset**, where there is no HV indication, **NGET** and the **Generator** will discuss and agree equivalent Mvar levels for the corresponding LV indication. Where a **Genset** is instructed to a specific Mvar output, the **Generator** must achieve that output within a tolerance of +/-25 Mvar (for **Gensets** in England and Wales) or the lesser of +/-5% of rated output or 25Mvar (for **Gensets** in Scotland) (or such other figure as may be agreed with **NGET**) by tap changing on the generator step-up transformer, unless agreed otherwise. Once this has been achieved, the **Generator** will not tap again without prior consultation with and the agreement of **NGET**, on the basis that Mvar output will be allowed to vary with **System** conditions.	MVAR

Instruction Name	Description	Type of Instruction
Target Voltage Levels	Target voltage levels to be achieved by the **Genset** on the **GB Transmission System** at the **Grid Entry Point** (or on the **User System** at the **User System Entry Point** in the case of **Embedded Power Stations**, namely on the higher voltage side of the generator step-up transformer. Where a **Genset** is instructed to a specific target voltage, the **Generator** must achieve that target within a tolerance of ±1 kV (or such other figure as may be agreed with **NGET**) by tap changing on the generator step-up transformer, unless agreed otherwise with **NGET**. In relation to each **Genset**, where there is no HV indication, **NGET** and the **Generator** will discuss and agree equivalent voltage levels for the corresponding LV indication. Under normal operating conditions, once this target voltage level has been achieved the **Generator** will not tap again without prior consultation with, and with the agreement of, **NGET**. However, under certain circumstances the **Generator** may be instructed to maintain a target voltage until otherwise instructed and this will be achieved by tap changing on the generator step-up transformer without reference to **NGET**.	VOLT
Instruction Name	Description	Type of instruction
Setpoint Voltage	Where a **Non-Synchronous Generating Unit**, **DC Converter** or **Power Park Module** is instructed to a specific **Setpoint Voltage**, the **Generator** must achieve that target within a tolerance of ±0.25% (or such other figure as may be agreed with **NGET**). The **Generator** must maintain the specified **Setpoint Voltage** target until an alternative target is received from **NGET.** Deviations of the actual **Setpoint Voltage** from the target must be corrected within the times specified in the **Bilateral Agreement**.	SETPOINT
Instruction Name	Description	Type of instruction
Slope	Where a **Non-Synchronous Generating Unit**, **DC Converter** or **Power Park Module** is instructed to a specific **Slope**, the **Generator** must achieve that target within a tolerance of ±0.5% (or such other figure as may be agreed with **NGET**). The **Generator** must maintain the specified **Setpoint Voltage** target until an alternative target is received from **NGET.**	SLOPE

Power Recovery

CC.6.3.15(a) ii) Each **Generating Unit** or **Power Park Module** shall be designed such that upon both clearance of the fault on the **GB Transmission System** as detailed in CC.6.3.15 (a) (i) and within 0.5 seconds of the restoration of the **voltage at the Grid Entry Point** to the minimum levels specified in CC.6.1.4 (or within 0.5 seconds of restoration of the voltage at the **User System Entry Point** to 90% of nominal or greater if **Embedded**), **Active Power** output shall be restored to at least 90% of the level available immediately before the fault. Once the **Active Power** output has been restored to 90% of the pre-fault 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 at 90% of the pre-fault level and that the oscillations are adequately damped. During the period of the fault as detailed in CC.6.3.15 (a) (i) each **Generating Unit** or **Power Park Module** shall generate maximum reactive current without exceeding the transient rating limit of the **Generating Unit** or **Power Park Module** and / or any constituent **Power Park Unit**.

CC.6.3.15(b) (iii) restore **Active Power** output, following **Supergrid Voltage** dips as described in Figure 5, within 1 second of restoration of the voltage at the **Grid Entry Point** to the minimum levels specified in CC.6.1.4 (or within 1 second of restoration of the voltage at the **User System Entry Point** to 90% of nominal or greater if **Embedded**), to at least 90% of the level available immediately before the occurrence of the dip except in the case of a **Non-Synchronous Generating Unit** or **Power Park Module** where there has been a reduction in the **Intermittent Power Source** in the time range in Figure 5 that restricts the **Active Power** output below this level. Once the **Active Power** output has been restored to 90% of the pre-dip level (or less in the case of a **Non-Synchronous Generating Unit** or **Power Park Module** where there has been a reduction in the **Intermittent Power Source** in the time range in Figure 5 that restricts the **Active Power** output below this 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 at 90% of the pre-dip level and that the oscillations are adequately damped.

Unbalanced faults

This requirement should not be placed on the older wind farms completed before the H/04 requirements were implemented. Therefore clause CC.6.3.15(c) should be modified.

(ii) In addition to meeting the conditions specified in CC.6.1.5(b) and CC.6.1.6, each **Non-Synchronous Generating Unit** or **Power Park Module** with a **Completion Date** after 1 April 2005 and any constituent **Power Park Unit** thereof 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 **GB Transmission System** operating at **Supergrid Voltage**.

Power Available Signal

Glossary and Definitions

Power Available

The potential available **Active Power** from a **Power Park Module** that can be delivered at the **Grid Entry Point** (or **User System Entry Point** for an **Embedded Power Park Module**) taking into consideration the number of **Power Park Units** in operation and the prevailing average energy source (eg wind speed) at the site over the sampling period.

CC.6.5.6 …….

(d) In the case of a **Power Park Module** ~~an~~ additional energy input signals (e.g. wind speed and **Power Available**) may be specified in the **Bilateral Agreement**. The signals may be used by NGET to establish the level of energy input from the **Intermittent Power Source** for monitoring pursuant to CC.6.6.1 ~~and **Ancillary Services**~~ and will, in the case of a wind farm, be used to provide **NGET** with both the available frequency response based on current wind speed and advanced warning of excess wind speed shutdown.

(e) For the **Power Available** and wind speed signals, the sampling period for each signal is required to be a maximum of 1 minute unless otherwise specified in the **Bilateral Agreement**.

Manned Control Rooms

CC.7.9 **Generators** and **DC Converter Station** owners shall provide a **Control Point** in respect of each **Power Station** directly connected to the **GB Transmission System** and **Embedded Large Power Station** or **DC Converter Station**. The **Control Point** shall be continuously manned (except for **Embedded Power Stations** containing **Power Park Modules** ~~in the **SHETL Transmission Area** which have a **Registered Capacity** less than 30MW~~ where the **Bilateral Agreement** in respect of such **Embedded Power Station** specifies that compliance with **BC2** is not required, where the **Control Point** shall be manned between the hours of 0800 and 1800 each day) to receive and act upon instructions pursuant to OC7 and BC2 at all times that **Generating Units** or **Power Park Modules** at the **Power Station** are generating or available to generate or **DC Converters** at the **DC Converter Station** are importing or exporting or available to do so.

Reactive Power output with voltage variation

CC.6.3.4 At the **Grid Entry Point** the **Active Power** output under steady state conditions of any **Generating Unit**, **DC Converter** or **Power Park Module** directly connected to the **GB Transmission System** should not be affected by voltage changes in the normal operating range specified in CC.6.1.4 by more than the change in **Active Power** losses at reduced or increased voltage. The **Reactive Power** output under steady state conditions should be fully available within the voltage range ±5% at 400kV, 275kV and 132kV and lower voltages, except for a **Power Park Module** or **Non-synchronous Generating Unit** if **Embedded** at 33kV and below (or directly connected to the **GB Transmission System** ~~in England and Wales~~ at 33kV and below) where the requirement shown in Figure 4 applies.

Cross referencing for LEEMPS provisions

PC.3.3 …..

PC.A.2.1.1
PC.A.2.2.2
PC.A.2.5.5.2
PC.A.2.5.5.7
PC.A.2.5.6
PC.A.3.1.5
PC.A.3.2.2
PC.A.3.3.1
PC.A.3.4.1
PC.A.3.4.2
PC.A.5.2.2
PC.A.5.3.2
PC.A.5.4
PC.A.5.5.1
PC.A.5.6

CC.3.4 …..

CC.5.1
CC.5.2.2
CC.5.3
CC.6.1.3
CC.6.1.5 (b)
CC.6.3.2, CC.6.3.3, CC.6.3.4, CC.6.3.6, CC.6.3.7, CC.6.3.8, CC.6.3.9, CC.6.3.10, CC.6.3.12, CC.6.3.13, CC.6.3.15, CC.6.3.16
CC.6.4.4
CC.6.5.6 (where required by CC.6.4.4)

Definition of Power Park Module

Glossary and Definitions

Power Park Module A collection of ~~**Non-synchronous**~~ **Generating Units** (registered as a **Power Park Module** under the **PC**) that are powered by an **Intermittent Power Source**, joined together by a **System** with a single electrical point of connection to the **GB Transmission System** (or **User system** if **Embedded**). The connection to the **GB Transmission System** (or **User System** if **Embedded**) may include a **DC Converter**.

Frequency response

High Frequency Response

An automatic reduction in **Active Power** output in response to an increase in **System Frequency** above the **Target Frequency** (or such other level of **Frequency** as may have been agreed in an **Ancillary Services Agreement**). This reduction in **Active Power** output must be in accordance with the provisions of the relevant **Ancillary Services Agreement** which will provide that it will be released increasingly with time over the period 0 to 10 seconds from the time of the **Frequency** increase on the basis set out in the **Ancillary Services Agreement** and fully achieved within 10 seconds of the time of the start of the **Frequency** increase and it must be sustained at no lesser reduction thereafter. The interpretation of the **High Frequency Response** to a + 0.5 Hz frequency change is shown diagrammatically in Figure CC.A.3.3.

Primary Response

The automatic increase in **Active Power** output of a **Genset** or, as the case may be, the decrease in **Active Power Demand** in response to a **System Frequency** fall. This increase in **Active Power** output or, as the case may be, the decrease in **Active Power Demand** must be in accordance with the provisions of the relevant **Ancillary Services Agreement** which will provide that it will be released increasingly with time over the period 0 to 10 seconds from the time of the start of the **Frequency** fall on the basis set out in the **Ancillary Services Agreement** and fully available by the latter, and sustainable for at least a further 20 seconds. The interpretation of the **Primary Response** to a – 0.5 Hz frequency change is shown diagrammatically in Figure CC.A.3.2.

Connection Conditions

CC.6.3.7 (a) Each **Generating Unit, DC Converter** or **Power Park Module** (excluding **Power Park Modules** in Scotland with a Completion Date before 1 July 2004 or in a **Power Station** in Scotland with a **Registered Capacity** less than 30MW) must be fitted with a fast acting proportional Frequency control device (or turbine speed governor) and unit load controller or equivalent control device to provide Frequency response under normal operational conditions in accordance with Balancing Code 3 (BC3). In the case of a **Power Park Module** the frequency or speed control devices may be on the **Power Park Module** or on each individual **Power Park Unit** or be a combination of both. The Frequency control device (or speed governor) must be designed and operated to the appropriate:

(i) European Specification; or

(ii) in the absence of a relevant European Specification, such other standard which is in common use within the European Community (which may include a manufacturer specification);

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(c) The Frequency control device (or speed governor) must meet the following minimum requirements:

(i) Where a **Generating Unit, DC Converter** or **Power Park Module** becomes isolated from the rest of the **Total System** but is still supplying Customers, the Frequency control device (or speed governor) must also be able to control System Frequency below 52Hz unless this causes the **Generating Unit**, **DC Converter** or **Power Park Module** to operate below its **Designed Minimum Operating Level** when it is possible that it may, as detailed in BC 3.7.3, trip after a time. For the avoidance of doubt the **Generating Unit**, **DC Converter** or **Power Park Module** is only required to operate within the System Frequency range 47 - 52 Hz as defined in CC.6.1.3.;

(ii) the Frequency control device (or speed governor) must be capable of being set so that it operates with an overall speed **Droop** of between 3% and 5%. For the avoidance of doubt, in the case of a **Power Park Module** the speed **Droop** should be equivalent of a fixed setting between 3% and 5% applied to each **Power Park Unit** in service;

(iii) in the case of all **Generating Units, DC Converter** or **Power Park Module** other than the **Steam Unit** within a **CCGT Module** the Frequency control device (or speed governor) deadband should be no greater than 0.03Hz (for the avoidance of doubt, ±0.015Hz). In the case of the Steam Unit within a **CCGT Module**, the speed governor deadband should be set to an appropriate value consistent with the requirements of CC.6.3.7(c)(i) and the requirements of BC3.7.2 for the provision of Limited High Frequency Response;

For the avoidance of doubt, the minimum requirements in (ii) and (iii) for the provision of System Ancillary Services do not restrict the negotiation of Commercial Ancillary Services between NGET and the User using other parameters; and

…………

APPENDIX 3

MINIMUM FREQUENCY RESPONSE REQUIREMENT PROFILE AND OPERATING RANGE for new Power Stations and DC Converter Stations.

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CC.A.3.4 TESTING OF FREQUENCY RESPONSE CAPABILITY

The response capabilities shown diagrammatically in Figure CC.A.3.1 are measured by taking the responses as obtained from some of the dynamic response tests specified by **NGET** and carried out by **Generators** and **DC Converter Station** owners for compliance purposes and to validate the content of **Ancillary Services Agreements** using an injection of a **Frequency** change to the plant control system (i.e. governor and load controller). The injected signal is a linear ramp from zero to 0.5 Hz **Frequency** change over a ten second period, and is sustained at 0.5 Hz **Frequency** change thereafter, as illustrated diagrammatically in figures CC.A.3.2 and CC.A.3.3. In the case of an **Embedded Medium Power Station** not subject to a **Bilateral Agreement** or **Embedded DC Converter Station** not subject to a **Bilateral Agreement**, **NGET** may require the **Network Operator** within whose **System** the **Embedded Medium Power Station** or **Embedded DC Converter Station** is situated, to ensure that the **Embedded Person** performs the dynamic response tests reasonably required by NGET in order to demonstrate compliance within the relevant requirements in the **CC**s.

The **Primary Response** capability (P) of a **Generating Unit** or a **CCGT Module** or **Power Park Module** or **DC Converter** is the minimum increase in **Active Power** output between 10 and 30 seconds after the start of the ramp injection as illustrated diagrammatically in Figure CC.A.3.2. This increase in **Active Power** output should be released increasingly with time over the period 0 to 10 seconds from the time of the start of the **Frequency** fall as illustrated by the response in Figure CC.A.3.2.

The **Secondary Response** capability (S) of a **Generating Unit** or a **CCGT Module** or **Power Park Module** or **DC Converter** is the minimum increase in **Active Power** output between 30 seconds and 30 minutes after the start of the ramp injection as illustrated diagrammatically in Figure CC.A.3.2.

The **High Frequency Response** capability (H) of a **Generating Unit** or a **CCGT Module** or **Power Park Module** or **DC Converter** is the decrease in **Active Power** output provided 10 seconds after the start of the ramp injection and sustained thereafter as illustrated diagrammatically in Figure CC.A.3.3. This reduction in **Active Power** output should be released increasingly with time over the period 0 to 10 seconds from the time of the start of the **Frequency** rise as illustrated by the response in Figure CC.A.3.2.

Figure CC.A.3.2 - Interpretation of Primary and Secondary Response Values

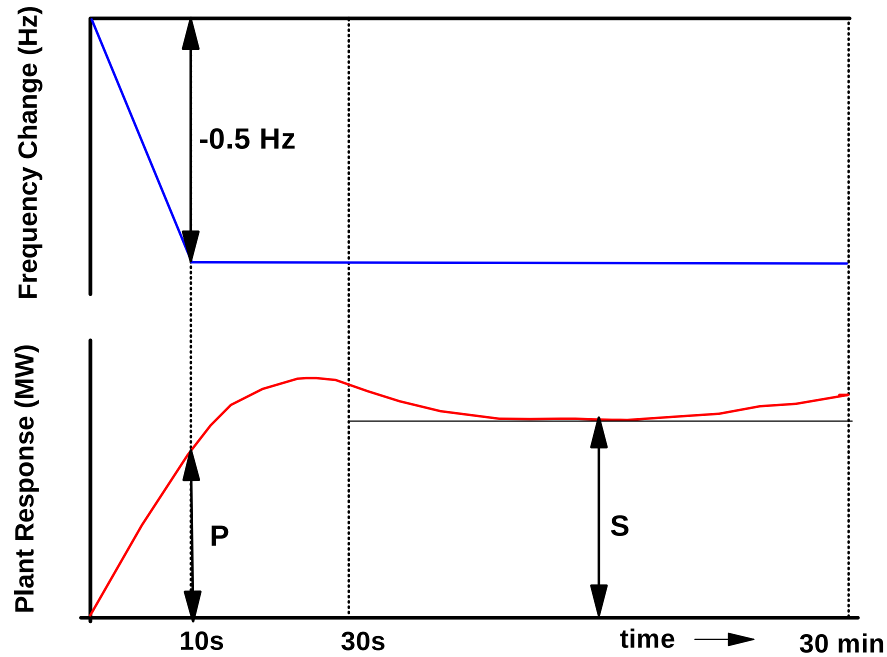
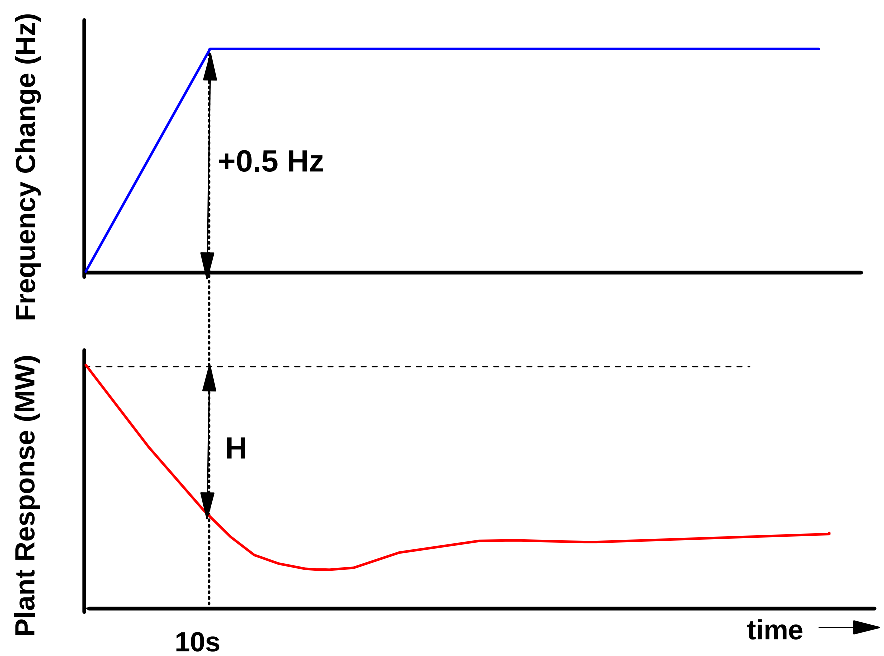


Figure CC.A.3.3 - Interpretation of High Frequency Response Values



Schedule 5 data

USERS SYSTEM DATA

DATA DESCRIPTION	UNITS	DATA CATEGORY
PROTECTION SYSTEMS The following information relates only to **Protection** equipment which can trip or inter-trip or close any **Connection Point** circuit breaker or any **GB Transmission System** circuit breaker. The information need only be supplied once, in accordance with the timing requirements set out in PC.A.1.4 (b) and need not be supplied on a routine annual thereafter, although **NGET** should be notified if any of the information changes.		
(a) A full description, including estimated settings, for all relays and Protection systems installed or to be installed on the **User's System;**		**DPD**
(b) A full description of any auto-reclose facilities installed or to be installed on the **User's System**, including type and time delays;		**DPD**
(c) A full description, including estimated settings, for all relays and **Protection** systems installed or to be installed on the **Power Park Module** or **Generating Unit's** generator transformer, unit transformer, station transformer and their associated connections;		**DPD**
(d) For **Generating Units** (other than **Power Park Units**) having a circuit breaker at the generator terminal voltage clearance times for electrical faults within the **Generating Unit** zone must be declared.		**DPD**
(e) Fault Clearance Times: Most probable fault clearance time for electrical faults on any part of the **Users System** directly connected to the **GB Transmission System**.	mSec	**DPD**

DATA DESCRIPTION	UNITS	DATA CATEGORY
POWER PARK MODULE/UNIT PROTECTION SYSTEMS Details of settings for the **Power Park Module/Unit** protection relays (to include):		
(a) Under frequency,		**DPD**
(b) Over Frequency,		**DPD**
(c) Under Voltage, Over Voltage,		**DPD**
(d) Rotor Over current		**DPD**
(e) Stator Over current,.		**DPD**
(f) High Wind Speed Shut Down Level		**DPD**
(g) Rotor Underspeed		DPD
(h) Rotor Overspeed		DPD