Guidance Notes for Power Park Developers

September 2008 – Issue 2

Foreword

These Guidance Notes have been prepared by National Grid plc to indicate to Generators the manner in which they should:

(i) Record compliance with the Grid Code, and Site Specific Technical Conditions in the Bilateral Agreement (BA).
(ii) Demonstrate such compliance to National Grid, through testing or otherwise, as required.

These Guidance Notes are prepared, solely, for the assistance of prospective Generators connecting to and / or using the GB Transmission System, either directly or Large Embedded Power Parks. In the event of dispute, the Grid Code and Bilateral Agreement documents will take precedence over these notes.

Small and Medium Embedded Power Parks should contact the relevant Distribution Network Operator (DNO) for guidance.

These Guidance Notes are based on the Grid Code, Issue 3, Revision 29, effective from the 1st September 2008. They have been developed from Issue 2 Draft 1 of the Guidance Note of February 2007 and reflect the major changes brought by Grid Code revision G/06 as finally approved by the regulator.

The Grid Code Review Panel has convened a working group to develop the processes and demonstrations of compliance contained in this guidance note for inclusion in the Grid Code. Details of the meetings of this working group can be found on the National Grid information website associated with the Grid Code. The conclusions of the working group will be subject to a consultation before inclusion in the Grid Code. It is currently expected that most of the content of this Guidance Note will be covered by the updated Grid Code with the exception of information for manufacturers covered in Chapter 3.

The Grid Code Review Panel has also convened a working group to develop the rid Code for the offshore regime. Details can again be found on the National Grid information website associated with the Grid Code. This guidance note will be updated, once the proposals on the Grid Code modifications have been reviewed and accepted by the relevant parties.

Definitions for the terminology used this document can be found in the Grid Code.

National Grid staff will be happy to provide clarification and assistance required in relation to these notes and on Grid Code compliance issues.

National Grid welcomes comments from manufacturers and developers including ideas to reduce the compliance effort while maintaining the level of confidence. Feedback should be directed to 'National Grid Generation Dynamic Performance' (01926 65 4601).

CONTENTS

ABBREVIATIONS

This section includes a list of the abbreviations that appear in this document:

Abbreviation	Description
AC / DC	Alternating Current / Direct Current
AVC	Automatic Voltage Control
AVR	Automatic Voltage Regulator
BA / BCA	Bilateral Agreement / Bilateral Connection Agreement
BC	Balancing Code(s)
BEGA	Bilateral Embedded Generation Agreement
BELLA	Bilateral Embedded Licence exemptible Large power station Agreement
BM	Balancing Mechanism
CC / CC.A	Connection Conditions / Connection Conditions Appendix
CCCR	Connection Condition Compliance Report (now obsolete, replaced by UDL)
CCGT	Combined Cycle Gas Turbine
CCL	Capped Committed Level
CD	Compact Disc
CE	Compliance Engineer
CMS	Compliance Monitoring Statements
CPD	Connected Planning Data
CUSC	Connection and Use of System Code
DFIG	Doubly Fed Induction Generator
DNO	Distribution Network Operator
DMOL	Design Minimum Operating Level
DPD	Detailed Planning Data
DRC	Data Registration Code
E&W	England and Wales
EDL / EDT	Electronic Data Logging / Electronic Data Transfer
FON	Final Operational Notification
FRT	Fault Ride Through
GB	Great Britain
GCRP	Grid Code Review Panel
HF / LF	High Frequency / Low Frequency
HV	High Voltage
IG	Induction Generator
ION	Interim Operational Notification
LEGA	Licence Exempt Generator Agreement
LON	Limited Operational Notification
MEL	Maximum Export Limit
MG	Minimum Generation
MLP	Module Load Point (Power Park Module / CCGT Module Load Point)
MW	Megawatt
NGET	National Grid Electricity Transmission
OC	Operating Code
OFGEM	Office of Gas and Electricity Markets
PC	Planning Code
PPM	Power Park Module
PPU	Power Park Unit
PSS	Power System Stabiliser
RC	Registered Capacity
SEL	Stable Export limit
SO	System Operator (National Grid)
SPT	Scottish Power Transmission
SSTN	Sub Station Name (connection point for power station)
SHETL	Scottish Hydro Electric Transmission Limited
STC	System Operator Transmission Owner Code
TO	Transmission Owner
UDL	User Data Library

1 INTRODUCTION

This document provides an overview of the preferred connection process Generators may follow to achieve and maintain Operational Notification. Operational Notification is required to allow Generators to synchronise and export power onto the national transmission system. In addition the document describes in greater detail technical studies and testing which demonstrate compliance with the Connection Conditions section of the Grid Code.

To achieve Operational Notification the generator must demonstrate compliance with the Grid Code and Bilateral Agreement. The Grid Code is a generic document which specifies requirements regardless of local conditions. The Bilateral Agreement is a site specific document agreed by National Grid and the Generator, which for technical reasons, may specify additional/alternative requirements. The total requirements placed on Generators are therefore the aggregation of those specified in the Grid Code and Bilateral Agreement.

All compliance evidence, test results and associated data are to be compiled into a single report referred to from here on, as the User Data Library (UDL). The User Data Library provides a convenient framework for Generators to submit data. It replaces the Connection Conditions Compliance Report (CCCR) which was previously used to compile such data. Depending on the nature of the data in the various subsections of the User Data Library, the System Operator (SO) or Transmission Owner (TO) will take the compliance lead role.

This particular edition of the guidance notes has been written for new generation technologies such as Power Parks. Its contents are based on experience gained from wind turbines but similar arrangements are expected to apply to other renewable technologies. A separate document exists for conventional synchronous plant.

Generators may, if they wish, suggest alternative tests or studies, which they believe will demonstrate compliance in accordance with the requirements placed on themselves and National Grid.

2 COMPLIANCE PROCESS

This section provides an overview of the compliance process, associated milestones and lifetime compliance issues.

2.1 Scope

National Grid will manage the Compliance Process for all transmission connected Power Parks and Embedded Large Power Parks, this guidance note covers these classes of Power Park. For embedded medium and small Power Parks the relevant Distribution Network Operator (**DNO**) is responsible for the compliance process and the User should therefore consult the relevant DNO. The DNO is also responsible for forwarding the relevant data to National Grid and the Transmission Owner.

The current Grid Code classifies all Power Parks, based on their Registered Capacity (RC), as follows:

England & Wales (NGET Area)	- Large ≥ 100MW, Medium ≥ 50MW, Small < 50MW
South of Scotland (SPT Area)	- Large ≥ 30MW, Small < 30MW
North of Scotland (SHETL Area)	- Large ≥ 10MW, Small < 10MW

2.2 Responsibilities and Requirements

The process detailed in this document will be managed by the 'National Grid Electricity Customer Manager' (see Appendix K of this document). This manager will be responsible for accepting all documents from the User and for issuing all documents by National Grid.

The Electricity Customer Manager will appoint a member of his staff, currently known as the Commercial Contact to streamline this process and provide a single point of contact for the Generator. The Commercial

Contact will supply a site specific tick sheet identifying the expected timescales for the various actions in this compliance process. Appendix J.5 of this document shows part of such a tick sheet.

A nominated lead engineer from 'National Grid Generation Dynamic Performance', known as Compliance Engineer (**CE**), will co-ordinate, witness and record any testing or monitoring required.

The Generator will be responsible for self certifying the compliance statements, submitting all data, carrying out tests and simulation studies. The self-certification of the compliance statements and the submission of data are described in the following sections. Required tests and simulations studies are discussed in detail later in these Guidance Notes.

The English language should be used in all correspondence and documents submitted to National Grid.

Operational Notification is required to allow Generators to synchronise and export power onto the national transmission system. Operational Notification is issued by National Grid in one of three categories, Interim, Final or Limited. The Interim Operational Notification (ION) is time limited and exists purely for the purpose of commissioning new plant. Final Operational Notification does not place time limits on the operation of the plant. To achieve Final Operational Notification (FON) the generator must demonstrate compliance with the Grid Code and Bilateral Agreement. Limited Operational Notification (LON) is time limited and is used for rectification of non compliant plant which previously had a FON. The timing, requirements and circumstances for issuing these notifications are detailed later in this document.

2.3 Self-Certification

All Generators are required to self certify, with suitable supporting evidence, that their equipment is compliant with Grid Code and Bilateral Connection Agreement.

The Bilateral/Construction Agreement between National Grid and the User places an obligation on the User to submit certifying statements to National Grid that, to the best of the information, knowledge and belief of the User, all relevant Grid Code conditions applicable to the User have been complied with. Certain Grid Code conditions refer to the Bilateral Agreement, in which the specific requirements of the particular connection are set.

To stream line the process National Grid will provide a site specific compliance statement pro-forma for each new generation project, which are to be completed by the Generator. In addition National Grid will provide a pro forma summary front sheet which should be used by the Generator to highlight any non-compliance issues.

The Generator will be required to confirm some basic details and select various compliance options. This information will be used to ensure the correct Grid Code clauses including the appropriate optional clauses when applicable, appear in the compliance statement. Options are also available to select the type of 'Fault Ride Through' (FRT) compliance evidence that the Generator prefers to provide. The information required is detailed in Appendix J of this document. In the event that the Users wishes to modify the information submitted, contact National Grid who will issue a revised pro-forma.

2.4 User Data Library

The User Data Library (UDL) replaces the Connection Conditions Compliance Report (CCCR) which was used to compile all such data previously.

The User Data Library provides a common directory structure where information in support of compliance statements can be submitted, shared and commented upon. The empty directory structure of the UDL will be provided by National Grid. The structure of UDL is given in Appendix I of this document. In addition, it also shows for each subsection who will take the lead role for reviewing submitted data, and who will share that data, the Transmission Owner or System Operator. For embedded Power Parks, the lead role taken by the Transmission Owner (TO) will be transferred to the Distribution Network Operator (DNO) and any data shown to be shared by the TO will be shared by the DNO and TO.

In England and Wales, National Grid is the Transmission Owner and System Operator. It is also the System Operator for SPT and SHETL Transmission Area (Southern and Northern Scotland respectively) but not the Transmission Owner in these regions. Scottish Power is the Transmission Owner in SPT Transmission Area and Scottish and Southern Electricity in the SHETL Transmission Area. In the case of off-shore installations National Grid is the System Operator but depending on the location of the off-shore installations, the connection may be owned by a Distribution Network Operator or a Transmission Owner. In this case the lead role and data sharing arrangements will be the same as that for a Power Park in non-National Grid transmission area.

At the end of this compliance process the User Data Library (UDL) should contain data as per the installed and tested plant. Consequently the UDL can only be completed at the end of this process. In the beginning the UDL will have signed legal agreements and the Committed Project Planning Data required by the Planning Code. As the process develops it will be updated. The nature of the data required at each stage of the process is described later in this document.

2.4.1 Format of Data

Generators are requested to submit all data in standard formats for incorporation into National Grid's information management system and forward to the relevant Transmission Owner where necessary.

Unless otherwise agreed submissions should be in the following file formats.

- Specifications, Statements, Agreements and Technical Reports in PDF format
- Signed Documents in scanned PDF format.
- Test result data points in XLS format (e.g. Excel ®)
- Performance Charts/Plots PDF and/or XLS format.
- Drawings in PDF or DWG format.
- Simulation Models in the form of transfer function block diagrams (using PDF or DWG format)

Where documents and diagrams are provided as supporting information, they should be legible and should include all relevant data assumptions (for example generator base, p.u., percentage values etc).

Where testing and monitoring results are provided they should be legible, appropriately sized, scaled and labelled.

2.4.2 Media Formats

At the time of writing the preferred format for submitting this information to National Grid is Compact Disk. Submitted compact disks should have the version number printed or written on them and should contain a revision history indicating what has changed from version to version. Users should be aware that other methods of submitting the information are currently being considered, including disclosure via the National Grid web site. Announcements relating to future developments in this area will be made via National Grids web site.

2.5 Process Documentation

The following documents are used by 'National Grid' to formally clarify the status of the Power Park Module as it progresses through the commissioning process. If required, the Commercial Contact can provide a pro forma for each of the statements to be provided by the Generator (see 1, 6, 8 and 9 below, as applicable).

Note: The terms "Power Park Module" and "Power Park Unit" as used by National Grid, have very different meanings. A "Power Park Unit" refers to a power source within a Power Park, a single wind turbine for example. A "Power Park Module", by contrast, refers to a source of energy with a single point of connection to a Transmission or Distribution Network. A group of wind turbines collectively connected to the network is therefore referred to as a “Power Park Module”.

Note: The documents are applicable to Power Parks that are directly connected to the Transmission System and Large Embedded Power Parks. Medium and Small Embedded Power Parks should contact the Distribution Network Operator.

1) ‘Statement of Readiness to Commence the Commissioning Programme’, submitted by the Generator, endorsed by Transmission Owner. This provides notification that the Generator is now ready to commence the Commissioning Programme referred to in the Construction Agreement.
2) Statement of Readiness to Complete the Commissioning Programme, submitted by the User, endorsed by Transmission Owner.
3) Transmission connected Generators only: ‘Statement of Completeness and Readiness to Energise High Voltage Equipment’, submitted by the Generator, endorsed by Transmission Owner. This provides notification that equipment has been tested and inspected and is now ready for energisation and on-load commissioning tests.
4) Embedded Large Generators only: ‘Statement of Completeness and Readiness to use the GB Transmission System’, submitted by the Generator, endorsed by Distribution Network Operator. This provides notification that the Generator is ready to energise the connection to the Distribution Network and use the GB Transmission System.
5) ‘Energisation Notice’: This provides notification that National Grid or the Distribution Network Operator agree that the Substation can be energised for the purpose of commissioning the Power Park Module and taking demand (power) from host network.
6) ‘Notification of Users Intention to Synchronise’, submitted by the Generator, endorsed by Transmission Owner. This provides notification that the Generator is ready to complete the Commissioning Programme, in respect of the works prior to synchronisation. At this point the Generator is expected to submit the Connected Planning Data and a report certifying that to the best of the information, knowledge and belief of the Generator all relevant Grid Code Conditions and site specific technical conditions applicable to the Power Park Module have been complied with.
7) ‘Interim Operational Notification’, provided by National Grid. This provides notification that National Grid is satisfied with the interim compliance evidence and the Generator may begin to close the Power Park Unit circuit breakers and bring the units ‘online’. Interim Operational Notification will be time limited to cover the commissioning and compliance demonstration period and may include operational constraints. Extensions to the Interim Operational Notification period may be available for reasonable circumstances.
8) ‘Final Operational Notification’ provided by National Grid.
9) ‘Limited Operational Notification’ provided by National Grid.

2.6 Overview of Connection, Energisation and Synchronisation Process

The Generator starts the process with an application for a Connection and Use of System Code (CUSC) contract with the System Operator (National Grid). The transmission contracted work will be covered by an agreement between the System Operator and the Transmission Owner. At that time the applicant has to submit Standard Planning Data as specified in Part 1 of Appendix A in the Planning Code section of the Grid Code.

Following the signing of a CUSC contract a commissioning programme is agreed upon. The Generator also agrees to provide statements of readiness and notifications to proceed, at key milestones within the commissioning program (Refer Section 2.5 above).

National Grid will provide the following to start the process.

- A site specific tick sheet identifying the expected timescales for the various actions (Refer to Appendix J.5 of this document).
- Site specific compliance statements for each new Connection, which are to be completed by the Generator (Refer to Appendix J.1 of this document).
- Pro forma summary front sheet which should be used by the Generator to highlight any known or potential non compliance issues (Refer to Appendix J.4 of this document).
- Required User Data Library structure (Refer to Appendix I of this document).

Stage 1 – Submission of Detailed Planning Data

The Grid Code specifies that the detailed planning data (DPD) as specified Part 1 of Appendix A in the Planning Code section of the Grid Code should be submitted within 28 days of accepting the CUSC contract. Part 3 of the User Data Library is the repository for such data.

Stage 2 – Commissioning of the Network of the Plant

The generator should notify National Grid the start of commissioning phase, by submitting the 'Statement of Readiness to Commence the Commissioning Programme' (Document 1 in Section 2.5) endorsed by the Transmission Owner or the Distribution Network Operator.

The Generator may have a supply from the local Distribution Network Operator for most of the commissioning work but the plant is not considered "energised".

Similarly the generator should notify National Grid the completion of commissioning phase, by submitting the Statement of Readiness to Complete the Commissioning Programme (Document 2 in Section 2.5), endorsed by the Transmission Owner or the Distribution Network Operator.

Stage 3 – Energisation Process

Energisation is an important milestone in the compliance process. It marks the energisation of the new busbars on to which the new generation will be connected. The day this takes place is referred to as the Completion Date.

Before Energisation could take place, the following conditions have to be met.

- All Commercial & Legal documents listed in Part A of the User Data Library (UDL) are agreed and included in the UDL.
- The Power Park Safety & System Operation arrangements have been endorsed, mainly by the host Transmission Owner or Distribution Network Operator and some by the System Operator. This is fully covered by Part 1 of User Data Library.
- The Connection Technical Data has been submitted as Part 2 of the User Data Library and endorsed by the Transmission Owner, System Operator and Elexon as indicated in the User Data Library structure.
- General DRC Schedules listed in Part 4.

NB Guidance on submitting the DRC schedules can be found in the document "Guidance Notes for Network Operators – Submission of Grid Code Data 2006/2007" which can be obtained from the National Grid web site.

In summary Parts A, 1, 2 and 4 should be submitted and endorsed by the party taking the lead compliance role for each of the subsections in the UDL.

When a transmission connected Generator has successfully submitted the above data and had them endorsed then the 'Statement of Completeness and Readiness to Energise High Voltage Equipment' (Document 3 in Section 2.5), should be submitted to National Grid by the Generator, endorsed by the Transmission Owner and any other affected Transmission Owners if necessary.

If National Grid accepts this statement, it will then issue the 'Energisation Notice' (Document 5 in Section 2.5. This provides notification that National Grid agrees that the Substation can be energised for the purpose of commissioning the Power Park Module and taking demand (power) from the host network.

Similarly when an embedded Generator has successfully submitted the above data and had them endorsed then the Statement of Completeness and Readiness to use the GB Transmission System (Document 4 in Section 2.5), should be submitted to the Distribution Network Operator (DNO). In this case the DNO will issue the Energisation Notice to the Embedded Power Park.

Stage 4 – Synchronisation Process

Following energisation and completion of all pre-synchronising commissioning of the plant, the generator will be ready to synchronise and export power.

In the case of windfarms energisation and synchronisation may happen on the same day or within few days of each other. Under such circumstances submission of data listed in Part 3 of the UDL could be submitted together with all the other parts of the UDL which are required for Energisation.

When the Generator has completed all other commissioning prior to synchronising, the Generator is expected to submit the Connected Planning Data in Part 3 of the UDL and self certifying compliance statements. A 'Notification of Users Intention to Synchronise', will be submitted by the Generator and endorsed by Transmission Owner.

As synchronisation always follows energisation, at this stage National Grid should have all parts of the UDL, including self-certifying compliance statements with a Pro forma summary front sheet highlighting any known or potential non compliance issues. The UDL will contain among other things, simulation studies demonstrating compliance, simulation studies predicting plant behaviour during compliance tests and the compliance test programme. The plant data should include a validated model of the generator and its control systems, in transfer function diagram format.

When National Grid reviews all the endorsed data in the UDL and the accompanying self-certified compliance statements it will then consent to synchronisation. This consent is issued as an 'Interim Operational Notification' (**ION**) by National Grid. This provides notification that National Grid is satisfied with the interim compliance evidence and the Generator may synchronise. Interim Operational Notification will be time limited to cover the commissioning and compliance demonstration period and may include operational constraints. The ION will include a list of any outstanding issues which must be resolved within defined timescales, before Final Operational Notification (FON) can be achieved.

Note: For clarity, the Energisation Notice allows closure of the Power Park Module switch. The term 'synchronisation' used throughout this document refers to closure of any of the Power Park Unit switches and requires Operational Notification for the Power Park Module.

Stage 5 – Compliance Testing and Model Validation

Various compliance tests that need to be carried out are listed and described in Section 3. Results from these tests should demonstrate not only compliance with the Grid Code and Bilateral Agreement but also validity of the models submitted for the generator and its control systems. By simulating these compliance tests using the supplied models and comparing the results, the validity of the models can be demonstrated. If the models are not valid, the generator has to provide updates or modifications to the model until there is good agreement between simulation study results and recorded test results.

At this point there may be another stage "Extension of Interim Operational Notification" where the User requests an extension of the Interim Operational Notification (ION) if the commissioning and testing is not completed within the allotted period. The issue of an extension to an ION is subject to the User having made satisfactory progress towards the resolution of the outstanding compliance issues.

Stage 6 – Final Operational Notification

When all outstanding issues listed in the ION are resolved through compliance testing or otherwise, and all data submissions listed in the UDL have been endorsed by the relevant party, the time limitation placed through the ION can be removed and the Generator is issued with a Final Operation Notification (FON).

2.7 Week 24 Data Process

It is a requirement of the Grid Code (PC.4.3) that all Generators submit Standard and Detailed Planning Data on an annual basis. National Grid will contact Generators on week 17 requesting an update of DRC Schedules 1, 2, 4, 5 and 14 which unless otherwise agreed with National Grid, must be provided by the Generator in week 24.

2.8 Lifetime Compliance

The "lifetime compliance process" ensures that plant remains compliant throughout its lifetime. Plant will have been compliant at the time Final Operational Notification (FON) was issued but gradual degradation or replacement can result in a change of status.

After the issue of a FON National Grid will continue to monitor the plant performance and will discuss any concerns with the Generator as part of a normal and ongoing liaison process. This monitoring is particularly focussed, but not exclusively, on performance during frequency incidents and system fault events. In addition the Generators should inform National Grid if the Users system is about to become, or as soon as existing plant becomes non compliant through gradual degradation, or because the User plans to replace or enhance existing plant. National Grid should be informed even if the modification or new plant will be Grid Code compliant. For example if a control system is replaced by a better one, it might fulfil all Grid Code requirements but the model previously submitted would have become invalid and therefore not fit for simulation studies.

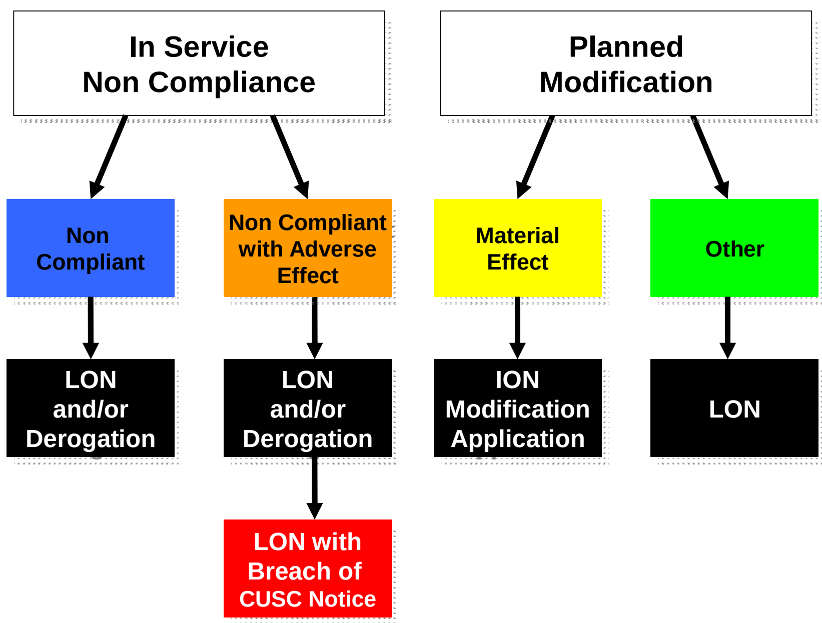


Figure 2.8 – Plant status whilst re-establishing compliance

The status of the plant, in terms of "Operational Notification" from National Grid, whilst the User re-establishes compliance is shown in figure 2.8 and is dependant upon a number of factors, as shown by the diagram and described in the following text.

2.8.1 In Service Non Compliance

The life time compliance process will be triggered, either as a result of an issue arising from National Grids monitoring or as a result of User notifying National Grid of a non compliance. In notifying National Grid of a non compliance as soon as it arises, the generator should include details indicating the nature of the problem, any restriction arising from it and provide an indication as to when it will be rectified.

Figure 2.8.1 below, details the interactions, timescales and resulting outcome (i.e. notification, issue of Limited Operational Notification and referral to OFGEM for a Time Limited Derogation), which are largely dependant on the significance of the non-compliance and the length of time the non compliance is predicted to or actually lasts for.

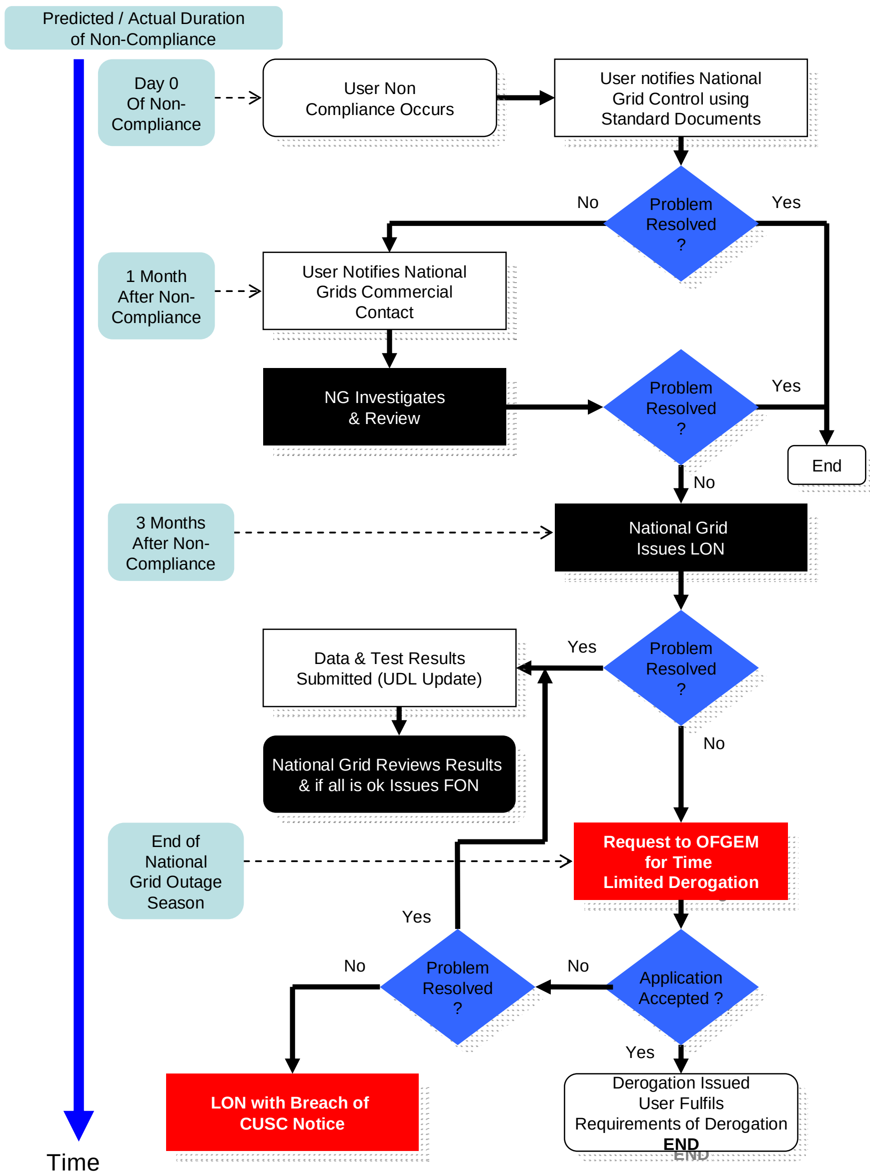


Figure 2.8.1 – Non Compliance Duration and Resolution Outcomes

Notes:

1. The Limited Operational Notification, if issued, will include a schedule of outstanding compliance issues together with timescales for their resolution. Generator Dynamic Performance within National Grid will monitor the situation and identify and notify the User of the tests and studies necessary to confirm that compliance with the Grid Code and Bilateral Agreement has been re-established. Regarding costs arising from non-compliance aspects, the principle that the party who has caused it pays will apply.
2. If the User claims the non-compliance is absolute and cannot be rectified economically the User and National Grid will be required to request the corresponding lifetime derogation. OFGEM may issue a derogation including terms and conditions. Alternatively OFGEM

may turn down the request. Requests to OFGEM for derogation can only be made by parties holding a Licence and only for Grid Code related issues.

3. Non compliances which are fixed and then reoccur more than once (i.e. are not fixed in an enduring manner) will on subsequent reoccurrences result in the initial stages of Figure 2.8.1 being bypassed. Ultimately this will lead to a request for Derogation being initiated.
4. Non Compliance with the Bilateral Agreement but compliance with the Grid Code will not result in requests for derogation but other parts of the procedure will still apply.
5. National Grid will specify the studies and testing required to prove compliance. National Grid will monitor progress of the compliance process and review the evidence. The User remains responsible for progressing resolution so that it complies with its obligations under the CUSC and Grid Code.
6. User's should provide evidence to National Grid of compliance in the form of an updated User Data Library and should include appropriate test and study results.

2.8.2 In Service Non Compliance – Adverse Effect

Where the non compliance does have an adverse effect on National Grid or adversely affects other Users of the system, the User will be notified in writing as soon as possible seeking confirmation that the User will take steps to restore compliance on an urgent basis. Failure to restore compliance may, lead to notification of default and de-energisation in accordance with National Grids rights under the CUSC.

2.8.3 Planned Modification

The User is required to notify National Grid of changes to plant and control systems which result in or have the potential for changing operational characteristics (including the submitted data and models). In addition a new model for the modified or new plant should be submitted to National Grid. These two actions have to be carried out as early as possible so that National Grid can evaluate whether the modified plant will be compliant and will not adversely affect the transmission system or other User's plant.

A Limited Operational Notification (LON) will be issued if there is no Material Effect (as defined in the CUSC) as a result of the changes or an Interim Operational Notification (ION) if there is a Material Effect. The plant will be tested for compliance, where National Grid considers it necessary and assuming the tests indicate that the modified plant is compliant, a Final Operational Notification will be issued.

In situations where some plant/equipment is replaced with newer variants, which are required to and are capable of meeting the latest Grid Code requirements, but the overall performance remains limited to some previously agreed level by other plant not being replaced: National Grid will take a pragmatic view to the level of performance which needs to be achieved and demonstrated. The extent of the design review, the studies required, the testing and the model updating required will be defined on a case by case basis, selecting appropriate parts from this document.

3 GENERIC POWER PARK UNIT TYPE VALIDATION

Power Park Modules are generally comprised of a large number of identical Power Park Units. Within manufacturing tolerances, the performance of a specific Power Park Unit type is normally reasonably constant from unit to unit which ever site they are installed on. It is therefore possible to register various aspects of this performance and the associated data once, and then reference this data for some or all of the sites which use this particular type of equipment. This should reduce the volume of work required by Users, Power Park Unit manufacturers and for National Grid. In addition it will provide a route for detailed data that Power Park Unit manufacturers regard as commercially sensitive to be sent directly to National Grid without publication to the User(s).

3.1 Background to Generic Power Park Unit Type Validation

The generic compliance process allows manufacturers to work directly with National Grid in order to exchange information and evidence of compliance without data passing through the project chain. Figures 1 to 3 illustrate the differences in the two processes. Figure 1 demonstrates the conventional process where the data flow is always via the power station or power park developer.

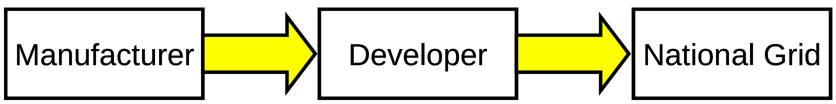


Figure 1 – The conventional compliance process data route

Figure 2 shows the one time process to fill the generator equipment 'type' register. It may be that information only comes from the manufacturer although a developer may be involved by providing site test opportunities. The data will comprise of a report on one or more of the aspects outlined below.

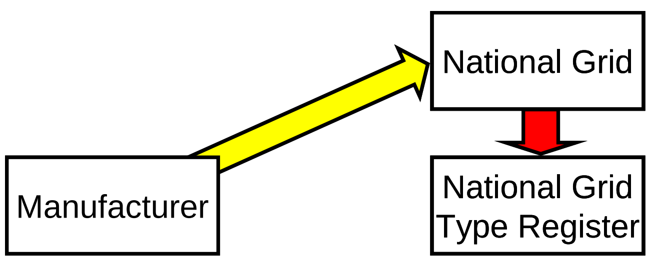


Figure 2 – The Type Register is filled with a selection of generic data

Figure 3 illustrates the process for referencing and using 'generic' data. Each project can, where appropriate, reference information held in the National Grid generator equipment Type Register substituting information that they are required to submit before connecting to the GB transmission system and in lieu of some aspects of Grid Code testing. Developers will not have access to this information from National Grid and the only requirement is to obtain the correct reference from the manufacturer. If no relevant or insufficient data is held in the Type Register then the data must be provided in full by the developer.

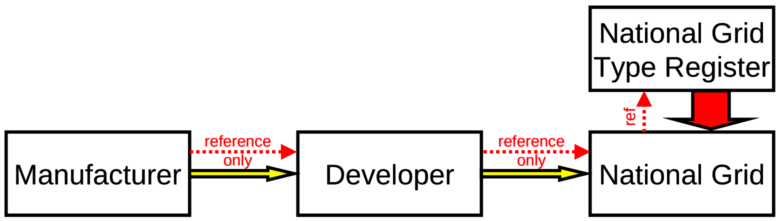


Figure 3 – The generic data (red arrow) is referenced but cannot be seen by the developer. There will still be some requirement for site specific data (yellow arrow).

3.2 Confidentiality Provisions

Data submitted by developers under the Data Registration Code (Grid Code) is protected by the confidentiality agreement contained in the Connection and Use of System Code (CUSC) and System Operator Transmission Owner Code (STC). This does not explicitly cover generic data sent from manufacturers directly to National Grid as it does not necessarily relate to a specific project. It is therefore necessary for manufacturers to sign a confidentiality agreement with National Grid prior to any exchange of information.

Please note that National Grid cannot sign individual manufacturer's confidentiality agreements as they may not cover the following aspects which are necessary to participate in the generic compliance process.

1) This agreement has been written to reflect the confidentiality provisions in the CUSC which deals with the confidentiality of data as between National Grid and Developers generally. National Grid will NOT however be permitted to release this 'generic' information back to developers (with the exception of the generic information document reference as originally submitted) which is unlike data submissions received through the normal project chain.

2) Some aspects of data must be passed to other Transmission System Operators and Owners in GB for system operation and design reasons as per the System Operator and Transmission Owner Code (STC).

3) The 'Purpose' as defined in the Agreement reflects the purposes for which National Grid do (and are permitted under the CUSC) to use information provided to National Grid by developers through the normal project chain.

4) The agreement is subject to the laws of England & Wales because the entire framework within which this data will be used is structured around English law and if the data was directly provided by a Developer it would be subject to English law.

5) Company Policy requires National Grid business areas to adopt information and records management procedures that comply with all relevant legal requirements and are consistent with best practice as applied to their business needs. The records management procedure for this area

provides that this data must be kept for 7 years after the data is last used. This therefore requires that the data should be kept for a period equating to the life of any plant it refers to plus a period of 7 years. This is in line with normal project data submissions direct from developers.

6) National Grid may pass back information (e.g. computer models) to the manufacturer but does not accept any liability in respect of its accuracy.

If this agreement is not signed then the standard Grid Code data requirements apply and all data will be provided through the project chain. Failure to supply adequate data by either of these methods will result in non-compliance by the developer with the GB Grid Code and possible disconnection or denial of permission to connect to the GB transmission system.

3.3 Referencing Information in the Type Register

While generators may not see the Type Registered information they must ensure that the correct reference is used as the same provisions will apply to this data as a normal Data Registration Code or a User Data Library submission. The Type Register reference given by the Power Park Unit manufacturer will contain the following; manufacturer name, Power Park Unit type, date and report version number. The user should then reference the document in the appropriate place for example in lieu of fault ride through studies, assuming a suitable fault ride through report has been submitted, the user can enter the following sentence in the User Data Library;

> "*This information has been submitted generically to National Grid and can be found in the National Grid Type Register under document reference* '*manufacturerX_10MWturbinetype1_22Aug08_reportver001*"

3.4 Areas Suitable for Type Registration

The following areas have been deemed suitable for Type Registration by National Grid

(a) Fault Ride Through capability

(b) Reactive Capability

(c) Voltage Control

(d) Frequency Control

(e) Power Park Module mathematical model

(f) Fault in-feed contribution (Schedule 14 DRC)

Items (a), (b), (c), (d) correspond to actual Power Park Unit tests. Items (e) and (f) correspond to simulation studies. The manufacturer may chose to complete one or more of the above mentioned areas. In each case the manufacturer should submit a detailed report to National Grid for approval and consequent submission into the Type Register.

To achieve Type Registration for the items (a), (b), (c), (d), a series of tests and data submissions will be developed to demonstrate the performance characteristics of a single Power Park Unit. Details of these tests and submissions are to be agreed between the Power Park Unit manufacturer and National Grid. National Grid may wish to witness some or all of these tests.

To achieve Type Registration for items (e) and (f) National Grid and the Power Park Unit manufacturer will need to agree a series of simulations and data submissions which are suitable for entry into the Type Register in relation to either or both of the following areas;

(a) A mathematical model of the Power Park Unit and associated control systems in line with the requirements outlined in PC.A.5.4.2. In addition the performance of this model should be validated against test results including faults, voltage steps and frequency changes as is deemed to be appropriate by National Grid**.**

(b) Simulations illustrating the fault in-feed characteristics of a single Power Park Unit to various balanced and unbalanced faults.

3.5 Submitting Data into the Type Register

Manufacturers considering Type Registration should talk to National Grid early in their planning stage using the Generation Dynamic Performance contact details contained in Appendix K.

In order to be considered for Type Registration, the Power Park Unit manufacturer should submit a report to National Grid outlining the details and results as appropriate for its consideration. Each report should have an appropriate reference including manufacturer name, type of report (e.g. Fault Ride Through etc.), Power Park Unit type, date and report version number.

National Grid will, following submission of all required reports and data, confirm to the Power Park Unit manufacturer in writing whether or not the Power Park Unit has achieved Type Registered status in respect of the relevant Grid Code requirement.

3.6 Achieving Grid Code Compliance with Type Registered Data

Users should note that using Type Registered data does not guarantee Grid Code compliance for a Power Park Module, but does indicate that the Power Park Unit is capable of achieving Grid Code compliance in the appropriate area. Limited tests may be required to confirm that the performance of the Power Park Module aligns with the data held by National Grid in the Type Register. Any Generator wishing to use Type Registered data is advised to contact National Grid early in the compliance process to determine if the information held in the Type Register is appropriate and sufficient in each case.

A generator should insert the relevant Type Register reference in the appropriate place in the Data Registration Code data submission and / or in the User Data Library. A Type Register reference will be considered by National Grid in place of the following;

(a) Data Registration Code data submissions;

(i) A mathematical model suitable for representation of the entire Power Park Module as per the requirements in the Grid Code. For the avoidance of doubt only site specific parameters will still need to be submitted by the Generator.

(ii) Data Registration Code Schedule 14 full site specific fault in-feed information. For the avoidance of doubt this option still requires a complete Data Registration Code schedule 5 submission.

(b) Fault simulation studies;

National Grid will no longer require Fault Ride Through simulation studies to be conducted as per the Grid Code requirements provided that;

(i) Relevant Power Park Unit data is held in the Type Register, and

(ii) For each type and duration of fault, the expected minimum retained voltage is greater than the corresponding minimum voltage achieved and successfully ridden through in the Type Register Fault Ride Through report.

(c) Reduced commissioning testing;

Where a Power Park Unit has been Type Registered for one or more of the following

(i) Reactive range

(ii) Voltage control

(iii) Frequency control

National Grid may agree a reduced program of compliance testing depending on the information held in the Type Register and the control methodology in operation at the Generator's site. This should be discussed and agreed between National Grid and the Generator.

It is the responsibility of the User to ensure that the correct Type Register reference is received from the Power Park Unit manufacturer. National Grid may contact the Power Park Unit manufacturer directly to ensure that the correct Type Register reference is used. If National Grid believe the reference is incorrect or the referenced data is inappropriate then permission to use the Type Register data may be refused.

4 SIMULATION STUDIES

4.1 General

The simulation studies described here, and Power Park Unit type and site tests described in sections 3 and 5, provide indicative evidence that the requirements of the Grid Code and a typical Bilateral Agreement have been met. However if the study requirements specified here, are at variance with the Bilateral Agreement then the Bilateral Agreement requirements will take precedence. In this case the Generator should contact National Grid to discuss and agree an alternative program and success criteria.

In general Simulation Studies are required where it is impractical to demonstrate capability through testing as the effects on other system Users would be unacceptable. The simulations must be based on the validated models supplied to National Grid in accordance with Grid Code Planning Code Appendix section 5.4.2 (PC.A.5.4.2).

The following sections outline validation of the Power Park Unit and Module models and the Simulation Studies that are required.

4.2 Validated Models

The Generator is required to provide National Grid and the Transmission Owner with a model of their Power Park Module as detailed in PC.A.5.4.2 (a to h) of the Grid Code. The model data is to be provided in a block diagram format, complete with Laplace equations and all associated parameters for the site in question. Control systems with a number of discrete states or logic elements may be provided in flow chart format if a block diagram format does not provide a suitable representation. The electrical system is to be provided as a single line diagram.

The model structure and complexity must be suitable for National Grid to integrate into their power system analysis software (currently DigSilent). In cases where the model's functionality cannot be correctly or satisfactorily represented within National Grid's power system analysis software, the Generator may be required to liaise with National Grid to determine appropriate interpretation.

All model parameters must be identified along with units and site-specific values. A brief description of the model should ideally be provided as ultimately this will save time and money for both parties.

The model representation provided should ideally be implemented on a power system analysis software package of the Generator's choosing, as it is otherwise highly unlikely to produce valid results when compared with the test results from the real equipment. In the event the model does not produce the correct output, the data submission will be considered incorrect and not contractually compliant. National Grid will confirm model accuracy using its power system analysis software.

The model also needs to be suitable for integration into the power system analysis software used by the relevant Transmission Owner (if not National Grid). Support may be required from the Generator to implement and if necessary modify the model representation for use on the Transmission Owner's power system analysis software (ordinarily this will not be the case if the model has already been satisfactorily implemented at National Grid).

National Grid encourages developers to work with manufacturers to develop the use of standard models for each type of Power Park Unit. This information can be provided in the type validation report and this will minimise the work needed by all parties to validate Power Park models at each new site.

It is the responsibility of the Generator to provide information as described in the planning code, which enables National Grid to model the UK Power System. The following validation studies are requested / required:

<table>
<tr><td rowspan="2">Power Park Unit Model Validation</td><td>Ideally a manufacturer performs type testing on a Power Park Unit to demonstrate its full reactive response capability. The manufacturer uses these results to validate the Power Park Unit model. This should include studies and tests for:

• Fault Ride Through
• Voltage Control
• Frequency Response</td></tr>
<tr><td>Where no factory type test validation information is available for a Power Park Unit model, it is the responsibility of the Generator to ensure that the response of the Power Park Unit model is validated against the results obtained in the Unit Tests. This should be done by simulating the tests using the submitted model.</td></tr>
<tr><td>Power Park Module Model Validation</td><td>Once the on site Voltage Control Module tests have been completed, Generators can use this data to validate the Power Park Module model against the results. This should be done by comparing the test results against those obtained by the developer from the submitted model.</td></tr>
</table>

4.3 STUDY 1 - Steady State Reactive Capability across the Voltage Range

National Grid Compliance Testing / Monitoring	
Title of Study: Steady State reactive Capability	Study Number: 1
User Procedure Reference:	

Description & Purpose of Study:

Grid Code CC.6.3.4 requires that the reactive power capability requirements of CC.6.3.2 must be fully available within the voltage range ±5% at 400kV, 275kV, 132kV and lower voltages. The only exceptions are:

- Embedded Generators with a User System Entry Point at 33kV or below
- Generators directly connected to the GB Transmission System at 33kV or below.

See Appendix A.1.2 for details on the above and other variations in requirements which depend on location and completion dates.

Note: The Grid Code indicates that Generators must still be capable of providing the full reactive capability even if DNO connected Power Park Modules can not in practice achieve this because of limitations imposed by the DNO's network. Under these circumstances the studies should be performed ignoring the DNO network limitations.

Compliance Study Description:

As it is usually impractical and undesirable for voltage security, to operate areas of the system at the extremes of connection point voltage for testing. Consequently Load Flow type Simulation Studies are required to demonstrate that the full reactive capability can be delivered at the extremes of voltage and active power levels.

If the load flow studies demonstrate the Power Park Module tap changers have sufficient range and if all parts of Test 1 (see section 5.3) were performed at nominal PPU (Power Park Unit) voltage, then compliance can be demonstrated by simply using the following two load flows:

Study 1.1) Use a load flow study to demonstrate the capability of the Power Park Module to provide maximum lagging reactive power at Rated MW when the Grid Entry Point Voltage is +5% higher than nominal.

Study 1.2) Use a load flow study to demonstrate the capability of the Power Park Module to provide maximum leading reactive power at the Stable Export Limit when the Grid Entry Point Voltage is 95% of nominal.

Notes:

1. For Generators connected to the GB Transmission System at 33kV or below or with a User System Entry Point at 33kV or below (if embedded), the above studies should be performed to demonstrate any reactive capability lagging and leading at +5% and -5% nominal volts respectively. As a minimum the studies should demonstrate the Module can operate at Unity Power Factor at both +5% and -5% of nominal.
2. If the Power Park Units deviate from nominal voltage to meet the reactive power requirements then evidence must be provided by factory or site tests to demonstrate the Power Park Unit is capable of operating continuously operating at all points in each load flow. However this is not necessary if this capability has already been demonstrated during Power Park Unit type validation.

4.4 STUDY 2 - Voltage Control and Reactive Power Stability

National Grid Compliance Testing / Monitoring	
Title of Study: Voltage Control and Reactive Power Stability	Study Number: 2
User Procedure Reference:	

Description & Purpose of Study:

National Grid requires verification of the capability to provide continuously-acting and stable automatic voltage control over the entire operating range of the Power Park Module in accordance with Grid Code CC.6.3.8 and CC.A.7. The Simulations listed below are required, in conjunction with the Power Park Unit Type tests and the Power Park Module Site tests to provide supporting evidence of compliance with the Grid Code.

It is usually not possible to demonstrate the full transient response capability of a complete Power Park Module (CC.6.3.8 and CC.A.7) from unity power factor to maximum reactive power output due to the resultant step change in voltage seen by other Users connected to the system. Therefore this compliance will normally be supported by Power Park Unit testing and dynamic Simulation Studies.

Similarly in some situations it may not be possible to demonstrate control actions at the extremes of the reactive capability envelope due to restrictions on the Transmission or Distribution Systems. In which case compliance will normally be supported by Power Park Unit testing and dynamic Simulation Studies.

Compliance Study Description:

The dynamic simulations should be completed using the verified Power Park Unit models, models of any other reactive sources and all associated voltage and reactive power control systems within the Power Park Module. Models of discrete reactive power sources such as switched capacitor elements must be verified to ensure the representation of switching delays and logic timing is correctly represented. Unless otherwise stated the baseline operating conditions should be:

- Active power = Rated MW
- Minimum Transmission System Fault Level
- Nominal Network Voltages for zero MVAr at the Grid Entry Point

Study 2.1) Demonstrate the maximum step change profile of lagging reactive power by a sufficiently large negative step in the system voltage to cause maximum reactive power change at any active power output above 20% of Rated MW.

Study 2.2) Demonstrate the maximum step change profile of leading reactive power by a sufficiently large positive step in the system voltage to cause maximum reactive power change at any active power output above 20% of Rated MW.

Study 2.3) Step the voltage at the relevant voltage control point by 2% in the direction of any reactive power limits (if applicable) when operating within 5% of MVAr limits to confirm control stability (CC 6.3.8 (c)).

Studies 2.1, 2.2 and 2.3 will be waived for type validated Power Park Units, provided the Power Park Module does not require the support of other reactive power sources. If the Power Park Units do require the support of other reactive power sources, National Grid may require further verification of capability based on the simulations included in this study.

4.5 STUDY 3 - Fault Ride Through

National Grid Compliance Testing / Monitoring	
Title of Study: Fault Ride Through	Study Number: 3
User Procedure Reference:	

Description & Purpose of Study:

Generators and manufacturers can demonstrate fault ride through compliance with CC.6.3.15 through one of three methods known as level 1, 2 or 3. Refer to section 5.6 and Appendix E.1 for further details of each level and a description of 'Mode A & B' fault requirements as discussed below.

For level 1 and 2 type-tested Power Park Units, a simplified representation of the power system network can be used for the design study, provided that for this simplification:

1. The calculated voltage at the Power Park Unit terminals must be greater than the voltage the Power Park Unit was able to ride through during the type tests.
2. The simplified calculation produces less favourable conditions (i.e. a worst case result) than would be experienced should a fault be applied to the real system or a more complex model of the system.

In the event that the simplification produces conditions which are too severe, a detailed simulation of the network can be used which should produce more favourable conditions but will take more effort to calculate. More details of this simplified approach are given in Appendix F of this document.

Note: For Power Park Units which can demonstrate fault ride through at zero retained volts, project based Fault Ride Through studies are not required.

Level 1 or 2: Extrapolation of Type Validation Data (only if type validated)

Type validated Power Park Units will have demonstrated their capability to ride through test circuit faults with similar characteristics to the faults that may occur on the Supergrid close to the Power Park Module. The objective of these studies is to confirm that the type validation tests were sufficiently representative of the impact of Supergrid faults for the site in question.

Ideally these studies would utilise verified models capable of accurately representing the behaviour of the Power Park Units in unbalanced fault conditions. However, in many cases the models available only provide indicative behaviour and are not suitable for unbalanced analysis.

Therefore the objective of these studies is to provide a relatively easy route to demonstrating compliance by making simplified extrapolations upon the proven capability and characteristics observed during the type validation tests. The simplifications used in these studies reflect National Grid's desire to minimise the burden of evidence upon the Generator (see Appendix F of this document). In certain cases the simplifications may not be considered appropriate and alternative studies may be required.

Study 3.1) 'Mode A' Requirements - first 140msec of a fault

The objective of this study is to estimate the positive phase sequence (pps) and negative phase sequence (nps) network voltages that occur as the result of solid 3 phase and various balanced and unbalanced faults at the nearest Supergrid connection. Provided the sequence voltage deviations are less severe than demonstrated in the type validation tests, at the equivalent network location, then compliance with 'Mode A' requirements will be assumed.

- Retained 'pps' voltage ≥ than the retained 'pps' voltage, for all fault types demonstrated during the type validation tests, for at least 140msec, at the equivalent network location.

- Retained ‘nps’ voltage ≤ than the retained ‘nps’ voltage, for all fault types demonstrated during the type validation tests, for at least 140msec, at the equivalent network location.

Dynamic models, unbalanced load flows, sequence circuits or the technique described in Appendix F of this document, can all be used to illustrate the above retained voltages during Supergrid faults. The validity of these studies should be confirmed by ensuring the phase currents in the converged analysis correlate with the associated currents observed in the type validation tests.

Study 3.2) ‘Mode B’ Requirements - fault period following the first 140msec
The objective of this study is to estimate the retained voltages and associated durations that occur as a result of the balanced Supergrid voltage depressions given in Table 1 below. Provided these retained voltages and durations are equal to or higher than the retained voltages and durations than were demonstrated in the type validation ‘Mode B’ tests, at the equivalent network location, then compliance with ‘Mode B’ requirements will be assumed.

The type validation process should have demonstrated the capability of the Power Park Unit to withstand various levels of balanced voltage dip for tested periods. The tests should have recorded the reactive and active power contribution during these events.

Appropriate load flow or dynamic simulations can be used to illustrate the retained voltages during Supergrid faults. The validity of these studies should be confirmed by ensuring the active power and reactive power in the converged analysis correlate with the values observed in the type validation tests for the same retained voltage at the equivalent network location. The analyses should be repeated for each of the following Supergrid profiles in Table 1 below.

Note: If the Type Tests are performed to an under voltage profile where transformer terminal volts are lower than the profile shown in Figure 5 of CC.6.3.15 (b), this study is not needed and the Power Park Unit will be considered compliant with Mode B requirements.

Table 1 Summary of Voltage Dip Studies (Modes A, B & C)

% Retained Supergrid Voltage	3ph	ph – ph	2ph – E	1ph – E	Grid Code Ref	Power Recovery
0	0.14s	0.14s	0.14s	0.14s	CC6.3.15a	in 0.5 second post fault
30	0.384s				CC6.3.15b Including Figure 5	In 1 second post fault
50*	0.71s					
80	2.5s					
85	180s					
*50% retained voltage is to give an indication of being able to meet the slope from 0.14s to 1.2s on the voltage – time trace in CC6.3.15b Figure 5 for balanced faults						

The table above summarises the minimum studies which should be performed for fault modes A & B.

Level 3: Non-Type Validated (Case by Case)
Power Park Units that have not been type validated are required to undertake full dynamic studies to demonstrate their capability to ride through Supergrid faults at the nearest Supergrid connection and deliver the required power recovery.

Ideally these studies would utilise verified models capable of accurately representing the behaviour of the Power Park Units in unbalanced fault conditions. Technologies that are considered to be more capable of riding through unbalanced than balanced faults will not be required to undertake unbalanced studies (for example fixed speed simple induction machine wind turbines).

Validation of the models is of critical importance and will be considered on a case by case basis. The validation must include the performance of the mechanical system and response of the power capture control system. For example wind turbine models must include and validate the rotor dynamics and pitch control system behaviour.

All studies should use the minimum Supergrid fault level and Embedded Generators should use minimum fault level at the closest Grid Entry Point. For an embedded generator the minimum impedance between the power station and the closest Grid Entry Point can be derived from the maximum fault level at the User System Entry Point where the power station connects to the public network.

5 COMPLIANCE TESTS

5.1 General

The tests identified here and simulation studies described in section 4 provide indicative evidence that the requirements of the Grid Code and a typical Bilateral Agreement have been met. However if the test requirements described here are at variance with the Bilateral Agreement then the Bilateral Agreement requirements will take precedence. In this case the Generator should contact National Grid to discuss and agree an alternative test program and success criteria.

5.1.1 Additional Compliance Tests

National Grid may require further compliance tests or evidence to confirm site-specific technical requirements (in line with Bilateral Agreement) or to address compliance issues that are of particular concern. Additional compliance tests, if required, will be identified following National Grid's review of the Interim and Final submissions of User Data Library.

5.1.2 Variance in Requirements

It should be noted that various revisions to the Grid Code have been released over time and consequently the requirements placed on Users of the Transmission System vary depending on the project completion/connection dates. Therefore alternative rules may apply, refer to the project specific compliance statements provided by National Grid.

5.1.3 Witness Testing and Data Recorder Details

'National Grid Generation Dynamic Performance' may witness the agreed compliance tests. At each witnessed test, 'National Grid Generation Dynamic Performance' may wish to connect a data recorder for its own recording purposes. The Power Park will also be required to provide its own recording equipment to provide a back up to the test results should one of the recording instruments fail at the time of testing.

The Power Park is responsible for providing the signals as outlined in 5.1.4 below to the User's and National Grid's recording equipment. For National Grid purposes the signals provided are required to be in the form of dc voltages within the range -10V to +10V. The input impedance of the National Grid equipment is in the region of 1MΩ and its loading effect on the signal sources should be negligible. The signals supplied should be raw i.e. taken directly from a transducer or signal source. The Power Park must inform National Grid if the signal ground (0V) is not solidly tied to earth or of any other potential problems.

Signals supplied to the National Grid recording equipment from the Power Park Module control system (i.e. other than those directly from a transducer) should have a minimum sample/update rate of 1Hz for reactive range testing, 10Hz for frequency response testing and 100Hz for voltage control testing (although it is accepted that signals such as wind speed and wind direction may have lower effective sample rates). All signals should be appropriately scaled within the dc voltage range.

If some of the required signals are supplied directly from a transducer then the following specification should be observed.

1. The transducer(s) should be permanently installed at the Users location to easily allow safe testing at any point in the future, and to avoid a requirement for recalibration of the CTs / VTs.
2. The transducer(s) should be directly connected to the metering CTs / VTs or similar.
3. The following should be available from the transducer(s)
    a. Total Power Park MW
    b. Total Power Park MVAr
    c. Line – line voltage at Point of Connection or User System Entry Point as appropriate (kV)
    d. System Frequency (Hz)
4. The output should be suitably scaled within the range -10 to +10 Vdc. For example the following ranges would generally be acceptable to National Grid.
    a. 0MW to Registered Capacity 0-8Vdc

b. Max leading reactive power to max lagging reactive power -8 to 8 Vdc
c. 48 – 52Hz as -8 to 8Vdc
d. Nominal voltage -10% to +10% as -8 to 8Vdc

5. The transducers should have a response time no greater than 50ms to reach 90% of output.

It should be arranged for National Grid recording equipment to be on site one day prior to the test date. The Power Park representatives are asked to check, prior to the arrival of the National Grid equipment, that a 230V AC power supply is available and that the signals are brought to robust terminals at a single location. Suitable representatives from the Power Park Unit (or Power Park Module associated equipment as appropriate) manufacturer and the User should be available on site for the complete testing period and at least one day in advance to discuss testing and set-up the equipment.

For offshore Power Park Modules, the control and signals for the witnessing of all testing should be available at the onshore connection point to avoid the risks associated with off shore working.

Prior to witnessing tests National Grid may require test results from a single frequency response test at one convenient de-load point (see section 5.5 of this document).

5.1.4 Available Signals

The User should ensure that the following signals are available and are terminated at a single location for the purpose of connecting National Grid's and the User's own recording equipment.

1) Total MW
2) Total MVAr
3) Point of connection line-line Voltage (HV) (kV)
4) System frequency (Hz)
5) Injected signal (Hz / Volts as appropriate) or test logic signal
6) Available power (MW)
7) Power source speed (e.g. wind speed m/s)
8) Power source direction (degrees)
9) Power Park site voltage (MV) (kV)
10) Any other signals as agreed between the user and National Grid or as specified in the Bilateral Agreement

As a minimum, signals 1-4 should be available as dc voltages for National Grid to monitor on site. In some cases the remaining signals may only be available from the Power Park control systems as a download once the testing has been completed. National Grid will agree to this provided the full test results can be provided within 2 working days to National Grid Generator Dynamic Performance with all data at the appropriate resolution depending on the type of test. This solution should not unreasonably add a significant delay between tests or impede the volume of testing which can take place on the day.

5.1.5 The National Grid Type Register

Users may wish to reference data held in the National Grid Type Register to help to complete various parts of the compliance process (see Section 3 of this document). This can be achieved by placing the manufacturer document reference in the appropriate place in the Data Registration Code or User Data Library. This reference should be obtained by the User from the Power Park Unit manufacturer. Please note that it is the responsibility of the User to ensure that the correct reference is submitted to National Grid.

Even though different Power Park Modules may be comprised of the same Power Park Unit type, differences in performance can result; for example using different sources of dynamic reactive power. Submitting a Type Register reference can therefore not be a guarantee of compliance, and the suitability of the reference should be discussed with National Grid as part of the normal compliance process.

5.2 Practicalities & Procedure for Compliance Testing

Due to the volume, it is impractical to test each Power Park Unit contained in a Power Park Module.

5.2.1 Compliance Risk & Interim Operation

To commission the Power Park Units the developer will need to synchronise them. However the Power Park Module compliance tests can only be undertaken with at least 95% of the Power Park Units in service. In addition National Grid recognises developers may wish to synchronise some units to earn revenue, whilst the remaining units are commissioned i.e. prior to compliance testing.

Whilst operating under Interim Operational Notification, National Grid is can accommodate these aspirations providing the following risk mitigation actions are undertaken:

1. Units can be synchronised, provided the maximum rated capacity of those units in service at any time is less than both 50MW and 20% of Registered Capacity of the Power Park.

2. Staged testing carried out, as the percentage availability of the Power Park Module increases. The User must confirm to National Grid and provide results to demonstrate:

    - Voltage control testing (see section 5.4) has been successfully completed before the lesser of 20% or 50MW of the Power Park Module is operational. For the avoidance of doubt, these tests can be completed once a single turbine has been installed.

    - In addition, for a Power Park Module with a Registered Capacity of 100MW or above, the two following interim tests must be completed before 70% of the Power Park Module is operational. In each case the User must provide results to demonstrate:

        - Reactive power capability and voltage control testing (see section 5.4) has been successfully completed, with at least 50% of the units operational.
        - Frequency response (see section 5.5 parts 1 and 2) has been successfully completed, with at least 50% of the units operational.

Please Note: These tests do not exempt the Generator from undertaking the full compliance tests when all the Power Park Units are operational and intermediate results will not be considered as indicative of full Power Park Module compliance capability. In the case where a Power Station is comprised of multiple Power Park Modules, each module must complete the above tests as appropriate.

5.2.2 Prior to Synchronisation of the First Power Park Unit

'National Grid Generation Dynamic Performance' will act as the National Grid interface with the Generator for approval of all generator compliance test procedures.

At least 1 month in advance of the Interim Operational Notification, the Generator must provide 'National Grid Generation Dynamic Performance' with a schedule of commissioning tests and associated procedures for each Power Park Module. These should indicate those tests which, to their knowledge, may have an impact on the GB Transmission System or other Users.

National Grid will use this information to identify those tests, if any, which may have an adverse impact on the GB Transmission System, or to any equipment belonging to other Users of the GB Transmission System. Embedded Generators must also co-ordinate generator commissioning with the Distribution Network Operator (DNO). In particular, National Grid will require detailed information on:

- MVAr Capability Tests
- Voltage Control Tests
- Frequency Response Tests
- Fault Ride Through Tests

- Model Validation Tests

With this information, National Grid will be in a better position to assist the Generator to plan the commissioning tests and to advise the Generator of any requirements for commissioning test procedures well in advance of the tests themselves.

5.2.3 Following Synchronisation of Power Park Units

In addition to the above and following synchronisation the Generator is responsible for notifying the 'National Grid Control Centre' of any tests to be carried out on their plant, which could have a material effect on the GB Transmission System. The procedures for planning and co-ordinating all plant testing with the 'National Grid Control Centre is detailed in OC7.5 of the Grid Code (i.e. Procedure in Relation to Integral Equipment Tests). For further details relating to this procedure, refer to "Integral Equipment Tests - Guidance Notes" which can be found on National Grid's Internet site.

The Generator should be aware that this interface will normally be available in week-day working hours only. As best practice the Generator should advise the 'National Grid Control Centre' and in Scotland the relevant Transmission Owner, or Distribution Network Operator (if embedded) of the times and nature of the proposed tests at the earliest stage possible. If there is insufficient notice or information provided by the Generator, then the proposed testing may not be allowed to proceed.

'National Grid Generation Dynamic Performance' will remain the interface for technical discussions on testing and shall be responsible for witnessing tests where necessary and approving the Grid Code Compliance test procedures are sufficient for the purpose.

5.2.4 Compliance Testing with Limited Power Source Availability

Many of the compliance tests require operation at a significant proportion of Rated MW. An Interim Operational Notification extension may be provided to allow operation until sufficient resource is available to complete the compliance tests at a suitable level of generation. In some cases the compliance tests may be approved at reduced capacity provided National Grid are satisfied that the Power Park Module capability is sufficiently supported by generic type validation tests and site design data.

5.2.5 Compliance Testing of Power Stations Comprised of Identical Power Park Modules

Where a Power Station is comprised of two or more identical Power Park Modules, National Grid may allow reduced compliance testing on the remaining Power Park Module(s) provided that the first has successfully completed the full list of tests as specified in section 5.3. The reduced testing will consist of confirmatory tests which should be discussed and agreed between National Grid and the User.

5.3 TEST 1 - Reactive Capability

National Grid Compliance Testing / Monitoring	
Title of Test: Reactive Capability	Test Number: 1
User Procedure Reference:	

Description & Purpose of Test:

National Grid requires verification of the minimum leading and lagging reactive power capability of the Power Park Module, to demonstrate compliance with Grid Code CC.6.3.2. The capability is usually measured at the connection point to the public system and applies to the Power Park Module as a whole rather than individual Power Park Units. A summary of the Grid Code reactive capability requirements is given in Appendix A.1.

If the Power Park Module is comprised of Power Park Units which have been fully Type Registered for reactive capability, and the dynamic reactive power for the Power Park Module is solely provided by these Power Park Units or other Type Registered equipment, then the tests in this section will not be required assuming National Grid deem the information held in the Type Register to be appropriate, and the appropriate load flow studies (Study 1.1 and 1.2) have been completed and accepted by National Grid. If the Power Park Unit has not yet been Type Registered, National Grid, the Power Park Unit manufacturer and the User may agree to progress the Power Park Unit to Type Registered Status in lieu of the tests here. For more information please see Section 3 or contact National Grid Generation Dynamic Performance.

In addition it is necessary to demonstrate the Power Park Modules ability to deliver a requested steady state power output to an accuracy of 2.5% (CC.6.3.9) when not impacted by power source variation. While this is a governor system requirement, it is included here as it is a steady state measurement of reduced plant output which allows it to be combined with Reactive Capability testing without additional cost to the Generator.

The Reactive Capability testing is normally arranged with and witnessed by the 'National Grid Control Centre' at a mutually agreed time (as described in a National Grid note entitled 'New Generating Stations MVAr Capability Tests'). The test will be carried out under instruction from the National Grid control engineer and should be monitored and recorded at both the 'National Grid Control Centre' and by the Generator.

Verification of reactive power capability can be achieved by operation of the Power Park Module at following load points for the specified durations. Embedded Generators should liaise with the relevant Distribution Network Operator to ensure the following tests will not have an adverse impact upon the distribution network (OC.7.5). In situations where the tests have an adverse impact upon the distribution network, National Grid will only require demonstration within the limits of acceptable the network operating conditions.

Test 1.1) Operation in excess of 50% Rated MW and maximum lagging reactive power for 60 minutes.
Test 1.2) Operation in excess of 50% Rated MW and maximum leading reactive power for 60 minutes.
Test 1.3) Operation at 50% Rated MW and maximum leading reactive power for 5 minutes.
Test 1.4) Operation at 20% Rated MW and maximum leading reactive power for 5 minutes.
Test 1.5) Operation at 20% Rated MW and maximum lagging reactive power for 5 minutes.
Test 1.6) Operation at less than 20% Rated MW and unity power factor for 5 minutes – This test only applies to systems which do not offer voltage control below 20% of rated power.
Test 1.7) Operation at 20% or 50% of Rated MW for 30 minutes.

Witnessed at site by National Grid:

- Generally not by National Grid Generator Dynamic Performance.
- Yes by National Grid Control Centre

Results Required:

Although National Grid will monitor and record the reactive capability on the HV side of the connection, the User will be required to produce Power Park Module performance chart as specified in OC2.4.2.1 and provided in Grid Code submissions DRC Schedule 1.

As a minimum the following data for each test must be recorded and submitted to National Grid with the appropriate resolution as specified at the start of Section 5.

- MW - Active power at the applicable measurement point.
- MVAr - Reactive power at the applicable measurement point.
- System Voltage at Grid Entry Point (or User System Entry Point if Embedded).

Test Assessment

The test results will be assessed against:

• CC.6.3.2, CC6.3.8(c) & CC.6.3.9 of the Grid Code

Criteria of Assessment

The tests will be regarded as supporting compliance if:

• The reactive power required in each test is achieved within a tolerance of ±5%.

• The tests will record and verify the performance chart of the overall Power Park Module submitted to National Grid.

• For Test 1.7 the standard deviation of load error over a 30 minute period does not exceed 2.5% of registered capacity.

5.4 TEST 2 – Voltage Control

National Grid Compliance Testing / Monitoring	
Title of Test: Voltage Control	Test Number: 2
User Procedure Reference:	

Description & Purpose of Test:

These tests are to verify that the Power Park Module is equipped with a continuously-acting automatic voltage control that meets the requirements of CC.6.3.8 and CC.A.7. The results of these tests should also be compared by the Generator, to results obtained from the submitted generator model and associate studies as part of the model validation process (unless the model has been Type Registered and is deemed to be appropriate by National Grid for use in this instance, in which case it will have already been validated).

National Grid is mindful of the rarity of Power System Stabilisers (PSS) on non synchronous plant. If a PSS is required by National Grid it will be specified in the Bilateral Agreement. If a Power System Stabiliser is fitted additional testing will be required to evaluate the stabiliser performance in the time and frequency domains. Users should note the requirements of BC2.11.2 with regard to PSS commissioning and in service use. Examples of additional Module Test procedures if a PSS is present are included in Appendix B.3.1.

Embedded Generators should also liaise with the relevant Distribution Network Operator to ensure all requirements covered in this section are compatible.

If the Power Park Units have not been Type Registered then the tests will comprise of multiple step injections to the Power Park Module voltage reference, and where possible, multiple up-stream transformer taps. Examples of test procedures are included in Appendix B.2.4.

If the Power Park Units have been Type Registered, and National Grid deem the information held in the Type Register to be appropriate for this Power Park Module, a reduced set of compliance tests will apply. These will consist of a single 2% step or single up-stream transformer tap (followed by removal of the step or a tap back to the starting position) to confirm correct operation of the voltage control system. Provided these preliminary tests replicate the data held in the Type Register then no further voltage control testing will be required at this stage. If this is not the case then full voltage control testing may be required. Please note if dynamic voltage control is provided either fully or partially by equipment which has not been Type Registered then (for example a STATCOM in addition to Type Registered Power Park Units) then full voltage control testing will be required.

Witnessed at site by National Grid:

- Yes, for Power Park Modules equal to or greater than 100MW.
- Generally not for Power Park Modules of less than 100MW.
- Yes, for Power Park Modules with Power System Stabilisers.

Results Required:

Signals should be provided to National Grid in accordance with the guidance at the start of Section 5. This may be modified to suit specific sites following consultation with National Grid.

As a minimum the following data must be recorded and submitted to National Grid with the appropriate resolution as specified at the start of Section 5.

- MW - Active power at the applicable measurement point.
- MVAr - Reactive power at the applicable measurement point.
- Voltage at controlled busbar, usually the Grid Entry Point or User System Entry point if embedded.
- PSS (if fitted) – Internal PSS Control Signal
- Intermittent Power Resource (e.g. wind speed)
- Power Available
- Other signals relevant to the control action of the voltage controller as specified by National Grid.

Test Assessment

The test results will be assessed against:
CC.6.3.8, CC.A.7 and the Bilateral Agreement

Criteria of Assessment

The performance will be assessed against the performance requirements detailed in Appendix 7 of the Connection Conditions and the Appendix F5 of the Bilateral Agreement. In general

- An appropriate proportion of the full reactive capability of the Power Park Unit is delivered within 1 second. (CC.A.7.2.3.1(iii))
- The change in reactive output commences within 0.2s of the application of the step injection (CC.A.7.2.3.1(i))
- Any oscillations settle, to within 5% of the change in steady state reactive power within 2 seconds of the application of the step injection. (CC.A.7.2.3.1(iv))
- The final steady state reactive value according to the slope characteristic is achieved within 5 seconds of the step application. (CC.A.7.2.3.1(iv) and CC.A.7.2.2.5)
- Adjustable slope characteristic, 2 to 7%. NB The slope is calculated in terms of rated Power Factor, for example a 4% droop should result in a 4% change in volts when moving from unity PF to 0.95 exporting or importing.

5.5 TEST 3 – Frequency Controller Response Performance

National Grid Compliance Testing / Monitoring	
Title of Test: Frequency Response	Test Number: 3
User Procedure Reference:	

Description & Purpose of Test:

The tests, for compliance purposes, should; demonstrate the capability of each Power Park Module to continuously modulate active power to contribute to frequency control; validate the frequency controller model submitted to National Grid, assess dead-band, incremental droop, steady-state/dynamic stability of the frequency controller and demonstrate the robustness of the control system. At the same time, the tests will also be used to verify the Mandatory Services Agreement frequency response matrices, for frequency services and response capability assessment.

Where a Power Park Unit (or a number of Power Park Units) has been Type Registered for frequency controller response performance, a reduced set of compliance tests may apply provided National Grid deems the data held in the Type Register to be appropriate. In this case only the following confirmatory tests need be completed;

1) A +0.8Hz ramp over 30 seconds with the Power Park Module in Limited Frequency Sensitive Mode from maximum available power
2) A +0.5Hz ramp over 10 seconds with the Power Park Module in Frequency Sensitive Mode from a sufficient de-load point to allow unconstrained operation
3) A -0.5Hz ramp over 10 seconds with the Power Park Module in Frequency Sensitive Mode from a sufficient de-load point to allow unconstrained operation

If these tests do not correspond to the performance demonstrated in the data held in the Type Register then a full set of compliance tests will have to be conducted as outlined in Appendix D.

For Power Park Modules with a completion date after 1 April 2005 the established response capability will be checked to ensure its compliance with the minimum frequency response requirements set out in C.C.6.3.7. A brief description is given in Appendix D.

The frequency controller should be in Frequency Sensitive Mode or Limited Frequency Sensitive Mode as appropriate for each test. Simulated frequency deviation signals should be injected into the frequency controller reference/feedback summing junction. If the injected frequency signal replaces rather than sums with the real system frequency signal then an additional test should be performed with the Power Park / Power Park Unit in normal Frequency Sensitive Mode monitoring real system frequency over a period of at least 10 minutes. The aim of this test is to verify that the control system correctly measures the real system frequency for normal variations over a period of time.

For a Power Park Module, National Grid will request the User to conduct preliminary tests before the ION is extended to allow full output as per section 5.2.1. These tests may or may not be witnessed by National Grid Generation Dynamic Performance. In any case, the results should be sent to National Grid Generation Dynamic Performance for assessment.

Details of preliminary and main test procedures are included in Appendix D.1.

Witnessed at site by National Grid:

- Yes, for Power Park Modules greater than 100MW.
- May witness a selection of tests for Power Park Modules between 50MW and 100MW.
- Not usually for Preliminary Tests

Results Required:

Signals should be provided to National Grid in accordance with the guidance at the start of Section 5. This may be modified to suit specific sites following consultation with National Grid.

As a minimum the following data must be recorded and submitted to National Grid with the appropriate resolution as specified at the start of Section 5.

- MW - Active power at the applicable measurement point.
- Injected signal
- MVAr - Reactive power at the applicable measurement point.
- Voltage at controlled busbar, usually the Grid Entry Point or User System Entry point if embedded.
- PSS (if fitted) – Internal PSS Control Signal
- Intermittent Power Resource (e.g. wind speed)
- Power Available
- Other signals relevant to the control action of the voltage controller as specified by National Grid.

Test Assessment

The test results will be assessed against:

• CC.6.3.6, CC.6.3.7, BC3.5, BC3.6 and BC3.7 of the Grid Code

Criteria of Assessment

- Frequency control dead band less than ±0.015Hz.
- Fast acting proportional control delivered linearly with time over the period 0 to 10 seconds from the time of the start of the **Frequency** change as illustrated by the Plant Response in Figure CC.A.3.2. If there is an initial inherent delay in the change of **Active Power** output following a change in **Frequency**, this must be minimised as far as is reasonably practicable and in any event such a delay should be no longer than two seconds unless in National Grid's reasonable opinion a longer delay is unavoidable.
- Unit/module droop in the range of 3-5%.
- Continuous frequency modulation capability and stable operation from Designed Minimum Operating Level to Maximum Export Limit.
- Capable of withstanding frequency disturbances without tripping (CC.6.3.7).
- The responses obtained are equal to or exceed the minimum requirements for frequency response profile specified in Appendix CC.A.3 of the Grid Code i.e. Primary, Secondary & High Frequency Response capability of the module >10% on module Registered Capacity.
- Results verify the Mandatory Ancillary Services Agreement matrices to the satisfaction of National Grid.
- Responds to larger frequency rises in accordance with Limited Frequency Sensitive Mode Operation in accordance with BC3.7
- The DMOL must not be more than 55% of Registered Capacity.

The User should note that the test requirements are indicative. A meeting will be arranged to discuss and agree the timing of the tests, associated test programmes and any witnessing requirements.

5.6 TEST 4 – Fault Ride Through, Fault Contribution and Power Recovery

National Grid Compliance Testing / Monitoring	
Title of Test: Fault Ride Through, Fault Contribution and Power Recovery	Test Number: 4
User Procedure Reference:	

Description & Purpose of Test:

National Grid requires verification that each Power Park Module has the capability to ride through Supergrid faults [CC.6.3.15, CC.A.4]. This requirement is critical to network stability. Rapid recovery of active power following restoration of the Supergrid voltage is of particular importance.

Demonstrating fault ride through and power recover capability at site by applying Supergrid faults is not practical and other evidence mechanisms are needed. National Grid has identified three test levels for demonstration of compliance. The first two depend upon having previously demonstrated a level of ride through capability in a suitable test environment.

Level 1) The test circuits will utilise the full Power Park Unit with no exclusions (e.g. in the case of a wind turbine it would include the full wind turbine structure). The test would typically apply short circuits to a test network to which the turbine is connected.

Level 2) The test circuits will include all the Power Park Unit's electrical components (and associated control systems) which interface to the network but do not include the power capture or similar components. For example a wind turbine generator driven by a motor, on a motor generator test bed. In addition a separate test, appropriate to the technology, would then be carried out using the Power Park Unit (e.g. wind turbine) in order to asses the power capture components.

Level 3) Technical evidence, simulation and monitoring.

To contain system risk within reasonable levels, the compliance route described in level 2 and 3 will only be available for Power Park Modules with a Registered Capacity of less than 200MW and 100MW respectively. Exemptions to this limitation may be available for technologies considered to be low risk provided they are supported by appropriate validated models.

For levels 1 & 2 the type validation tests should fully characterise the fault ride through behaviour and capability of the Power Park Unit which should be at least as severe as those that will occur at the Power Park Unit terminals as a result of Supergrid fault conditions. The compliance design study detailed in section 4.5 provides guidelines as to how the test data may be acceptably extrapolated to confirm compliance on a site by site basis.

Compliance Test Description:

Level 1 & 2: Previously Type Validated to Fault Ride Through Level 1 (Full Type Test)

All fault ride through, fault contribution and power recovery site tests will normally be waived for Power Park Units previously type validated using these levels. Although National Grid will require some study evidence to correlate type test capability to the relevant site configuration, see study in section 4.5.

The type tests necessary for Fault Ride Through typically comprise of a Power Park Unit, its transformer and a test impedance to simulate the associated connection to the transmission network. Short circuits would then actually be applied to the equivalent of the Transmission Network.

Additional Level 2 Tests: Previously Type Validated to Fault Ride Through Level 2 (Partial Type Test)

For level 2 type validation may not include demonstration of the complete Power Park Unit's power recovery capability. If this is the case National Grid will require evidence that a complete Power Park Unit has the capability to ride through the drop in active power associated with faults and still meet the required recovery performance.

National Grid have identified a series of Power Park Unit power cycling tests which are considered as satisfactory evidence of power recovery capability. The 'Unit Power Cycling Test' is detailed in section E.3.

Level 3 - Technical Evidence and Monitoring:

The technical information provided by the developer must be sufficiently detailed, such that it equates to the evidence required for type validation. It is unlikely that this can be achieved without extensive audit of design data and detailed models, possibly by an independent organisation with appropriate expertise. This independent organisation will be procured by the developer and approved by National Grid. Generators pursuing this compliance level should contact 'National Grid Generator Dynamic Performance' to discuss the requirements and suitable organisations.

Design Modifications:

Details of modifications made to the Power Park Unit designs used for type validation must be provided along with a satisfactory justification of retained ride through capability and performance. The same justification must also be provided for any type levels that may be available (for example different ride through levels that may be available with the same base equipment type).

Witnessed at site by National Grid:

- Not relevant in most cases. Power cycling tests will generally be witnessed if required.

Results Required:

The test results should be recorded at the unit terminals, the fault location and any other locations in the test circuit which the manufacturer may wish to reference for site equivalence and compliance purposes.

The following data should be recorded for levels 1 and 2 Fault Ride Through tests, including captured voltage and current waveforms.

- Phase Voltages
- Positive phase sequence and negative phase sequence voltages
- Phase Currents
- Positive phase sequence and negative phase sequence currents
- MW - Active Power
- MVAr - Reactive Power
- Estimate of Power Park Unit negative phase sequence impedance
- Worst case current frequency components (integer, sub or inter harmonic) greater than 5% of the 50Hz component or detailed waveform.
- A description of the test circuit and the tests applied.

The following data must also be recorded for levels 1 and 2, however for level 1 these signals should be recorded in addition to the signals above, whilst level 2 they should be recorded for the Power Recovery Tests (see section E.4.2):

- MW – Active power at the generating unit.
- MVAr – Reactive power at the generating unit.
- System Voltage (HV)
- Intermittent Power Resource (e.g. wind speed)
- Power Available
- Mechanical Rotor Speed

- Blade Pitch
- Pitch Reference
- Real / Reactive, Current / Power Reference as applicable
- Other signals relevant to the control action of the fault ride through control (for model verification).

Test Assessment
The test results will be assessed against CC.6.3.15 (a), (b) & (c), CC.A.4.1, CC.A.4.2 & CC.A.4.3. In addition the test results will be used to justify extrapolation of type test data for demonstration of fault ride through compliance on a site by site basis. The data may also be used to validate the system model and to ensure transmission equipment is correctly rated and appropriate transmission protection is installed.

Criteria of Assessment
Compliance is verified if the unit capability has previously demonstrated capability in a controlled environment (type validation) and that study evidence (see section 4.5) shows the test environment to be equivalent or more demanding than the actual Power Park Location. Level 2 may require this to be further supported by a site 'power cycling test' (see section Appendix E.3).

Alternatively for those pursuing level 3 the criteria will be agreed on a case by case basis with National Grid.

APPENDIX A REACTIVE CAPABILITY

A.1 Summary of Grid Code Reactive Capability Requirements

The reactive capability requirements for a Power Park Module are specified in Grid Code CC.6.3.2. Grid Code CC.6.3.2 (b) requires that the Power Park Module should be capable of operating with no reactive power transfer to the public power system from zero power output to full output.

Grid Code CC.6.3.2(c) adds the requirement for the Power Park Module to be capable of operating with a range of reactive power outputs when producing more than 20% real power. Below 20% real power output the Power Park Module may continue to modulate reactive power transfer under voltage control or switch to no reactive power transfer as required in CC.6.3.2(b). In addition Grid Code CC.6.3.2(c) sets the point at which the reactive capability is to be delivered as the Grid Entry Point or User System Entry Point if Embedded.

Grid Code CC.6.3.4 states that the reactive power capability must be fully available at all system voltages in the range ±5% of nominal. The clause continues to offer a relaxation of the requirement which may apply if connected at 33kV or below. This capability is not normally tested but is demonstrated by simulation (see study 1 in section 4.3).

There are some variations on the requirements for reactive capability for Power Park Modules in Scotland based on their Completion Dates.

The minimum reactive power capability described in Grid Code CC.6.3.2 at the interface with the public power system is illustrated below. The MVAr capability can be reduced pro rata with the number of Power Park Units in service.

Figure A.1
Minimum Reactive Power Performance Chart

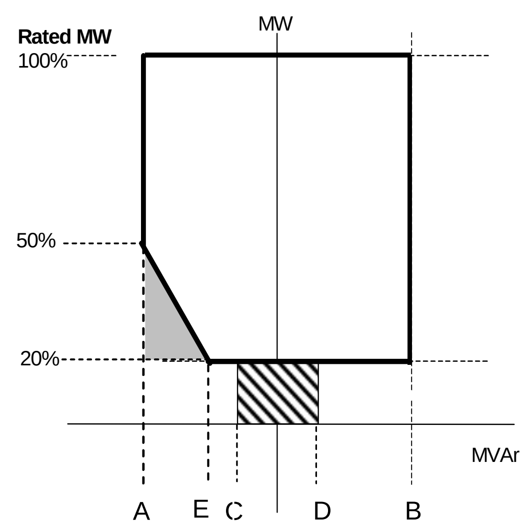
Point A is equivalent (in MVAr) to 0.95 leading Power Factor at Rated MW output.

Point B is equivalent (in MVAr) to 0.95 lagging Power Factor at Rated MW output.

Point C is equivalent (in MVAr) to -5% of Rated MW output.

Point D is equivalent (in MVAr) to +5% of Rated MW output.

Point E is equivalent (in MVAr) to -12% of Rated MW output.



For clarification at active power levels of below 20% the reactive power must be controlled to zero ±5% of Rated MW (in MVAr) if active voltage control is not offered below 20% power output. At active power levels above 20% the requirement only defines the minimum capability. Grid Code CC.6.3.8(c) requires that there is a smooth transition between Voltage Control at active power levels greater than 20% and reactive power control at active power levels less than 20%.

A.1.1 Contractual Opportunities Relating to Reactive Services

For some technologies there is an opportunity to provide an optional reactive services (beyond the basic mandatory reactive service) covering the period when the renewable energy source is not available (e.g.

when a wind turbine has no wind). Developers interested in providing such a service should take the opportunity of reactive capability testing to demonstrate this zero power reactive capability. The delivery of reactive power would be expected to be dynamic, i.e. responding to changes to system voltage in the same manner as normal operation.

A.1.2 Variations in Reactive Capability Requirements

The Grid Code is continually reviewed by National Grid and all Authorised Electricity Operators resulting in a document which is regularly updated, however existing plant is typically exempted from complying with new requirements. Consequently new requirements which are considered material to Users, are normally dependent on plant Completion Dates.

There are some variations to the Reactive Capability requirements that relate to older Power Park Modules. These are summarised below:

- Power Park Modules with completion dates before 1 January 2006 are required to comply with CC.6.3.2(b) which limits the maximum reactive power transfer between the Module and the Grid Entry Point to 5% of the Rated MW (i.e. the PPM should operate at Unity Power Factor ±5% MVAr).
- Power Park Modules in Scotland with completion dates after April 2005 and before 1 January 2006 should deliver the reactive capability shown in Figure A.1 or at the HV side of the 33/132, 33/275 or 33/400kV transformer or 0.95 lead to 0.9 lag at the Power Park Unit terminals.
- Power Park Modules in Scotland directly connected to the Transmission System with completion dates after 1 January 2006 should deliver the reactive capability shown in Figure A.1 at the HV side of the 33/132, 33/275 or 33/400kV transformer.

Generators with a User System Entry Point at 33kV or below and Generators directly connected to the GB Transmission System at 33kV or below, are only required to meet the relaxed voltage/reactive capability envelope illustrated below, see Figure A.1.2 (CC.6.3.4). The voltage shown in figure A.1.2 is measured at the Grid Entry Point or User System Entry Point.

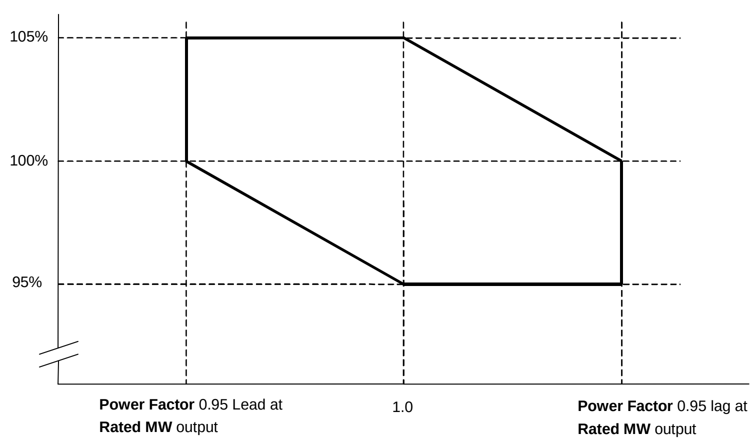


Figure A.1.2 – Reactive / Voltage range requirements for embedded or E&W Generators, connected at 33kV or below. For Generators in Scotland directly connected to the transmission system at 33kV or below the relaxation applies at the Grid Entry Point but the reactive capability values at the Grid Entry Point are equivalent to the delivery of 0.95 power factor at the HV side of the 33/132, 33/275 or 33/400kV transformer. This relaxation recognises that the power park developer does not have control of the transformer tapchanger to control voltages within his network.

Note: Figure A.1.2 specifies the minimum acceptable reactive capability when operating within the normal range of 95 to 105%. In the event that during system incidents, the voltage is ≤95% or ≥105%, plant should deliver the maximum (lagging or leading respectively) reactive power possible, whilst remaining within its design limits.

A.1.3 Summary of Steady State Load Accuracy Requirements

Grid Code CC.6.3.9 states:
*The standard deviation of **Load** error at steady state **Load** over a 30 minute period must not exceed 2.5 percent of a **Genset's Registered Capacity.***

With an intermittent power source this requirement applies when operating at power levels below the Maximum Export Level (MEL) which should reflect the availability of the power source.

To demonstrate compliance, the Power Park Module should operate for 30 minutes at a load significantly below the Maximum Export Level (MEL) for the period. The active power output and power available should be recorded with a sampling rate not less than once per minute.

A.2 Reactive Capability Compliance Tests

The Reactive Capability testing should be carried out when at least 95% of the Power Park Units within the Power Park Module are in service. The power available from the intermittent power source e.g. for wind turbines the wind should be sufficient for a Maximum Export Limit (MEL) >85% of Registered Capacity.

The Reactive Capability test is not usually witnessed by National Grid Generator Dynamic Performance but is monitored by the National Grid Control Centre. The Generator should ensure the tests are performed under instruction from the 'National Grid Control Centre' at a mutually agreed time (with details given in a National Grid note entitled 'New Generating Stations MVAr Capability Tests'). The test will be carried out under instruction from the National Grid Control Engineer and should be monitored and recorded at both 'National Grid Control Centre' and by the Generator.

The required tests should demonstrate the capability of the Power Park Module at the corners (A, B, E & F) of the envelope shown in Figure B.1 (or A.1.2 if applicable). Given the steady state nature of the Reactive Capability requirements implying that reactive output can be maintained indefinitely, the tests are carried out over a longer period than other compliance tests. The suite of tests shown in the table below, explore the extremes of the Reactive Capability envelope and check the steady state load error.

<table>
<tr><td></td><td colspan="3">Power Park Module Reactive Output</td></tr>
<tr><td>Active Power</td><td>Maximum lagging</td><td>Zero
(unity power factor)</td><td>maximum leading</td></tr>
<tr><td>Rated MW</td><td>60 minutes</td><td>-</td><td>60 minutes</td></tr>
<tr><td>50% Rated MW</td><td>5 minutes</td><td>-</td><td>-</td></tr>
<tr><td rowspan="2">20% Rated MW</td><td>5 minutes</td><td>-</td><td>5 minutes</td></tr>
<tr><td colspan="3">30 minutes[1]</td></tr>
<tr><td>Below 20% Rated MW</td><td>-</td><td>5 minutes[2]</td><td>-</td></tr>
</table>

[1] This test checks the ability to control active power can be conducted at any power output level between 50% and 20%. The Rated Output test and may be combined with the reactive capability tests.

[2]A test of capability below 20% is only required if voltage control below this level is not offered. This test should be conducted as follows in order to demonstrate a smooth transition between the voltage control operation above 20% output and reactive power control below 20% output:

Test No	Step	Description	Notes
		Plant in Voltage Control Target Voltage selected to generate a value of Lagging Reactive Power greater than 25% Rated MW	
	1	Module Power Output >20% Rated MW	
	2	Reduce Power Park Output to <20% as a ramp over 10 seconds	
	3	Hold Power Park Output <20% for 5 minutes	

The tests will be regarded as supporting compliance if:

- The reactive power transfer at the Grid Entry Point or User System Entry Point if Embedded equals or exceeds the minimum requirements defined in CC.6.3.2(c) when generating more than 20% active power.
- The transition between Voltage Control and Reactive Control at 20% output is smoothly controlled.
- The standard deviation of steady state load does not exceed 2.5%.

The Generator should note that the Grid Code (OC5.5.3) does specify a tolerance of ±5% of the capability requirement on the measured deliverable Reactive Power for life time compliance.

APPENDIX B VOLTAGE CONTROL

B.1 Summary of Grid Code Requirements

The generic requirements for voltage control are set out in the Grid Code Connection Conditions with any site specific variations included in the Bilateral Agreement. This section summarises the key requirements using the generic values included in the Grid Code.

Grid Code CC.6.3.8(c) requires provision of a continuously acting automatic voltage control which is stable at all operating points. The point of voltage control is usually the Grid Entry Point or User System Entry Point if Embedded.

Grid Code CC Appendix 7 requires:

- CC.A.7.2.2.2 The voltage set point should be adjustable over a range of ±5% of nominal with a resolution of better than 0.25%.
- CC.A.7.2.2.3 The voltage control system should have a reactive slope characteristic which must be adjustable over a range of 2 to 7% with a resolution of 0.5%. The initial setting should be 4%.
- CC.A.7.2.3.1 The speed of response to a step change should be sufficient to deliver 90% of the reactive capability within 1 second with any oscillations damped out to less than 5% peak to peak within a further 1 second.
- CC.A.7.2.2.5 The control system should deliver any reactive power output correction due from the voltage operating point deviating from the slope characteristic within 5 seconds.
- CC.A.7.2.2.6 The Power Park Module must continue to provide voltage control through reactive power modulation within the designed capability limits over the full connection point voltage range ±10% (CC.6.1.4) however the full reactive capability (CC.6.3.2) is only required to be delivered for voltages within ±5% of nominal in line with CC6.3.2 and CC.A.7.2.2 (b) or Figure 4 of CC.6.3.4 if applicable.
- Figure CC.A.7.2.2(b) Illustrates the operational envelope required and is reproduced below

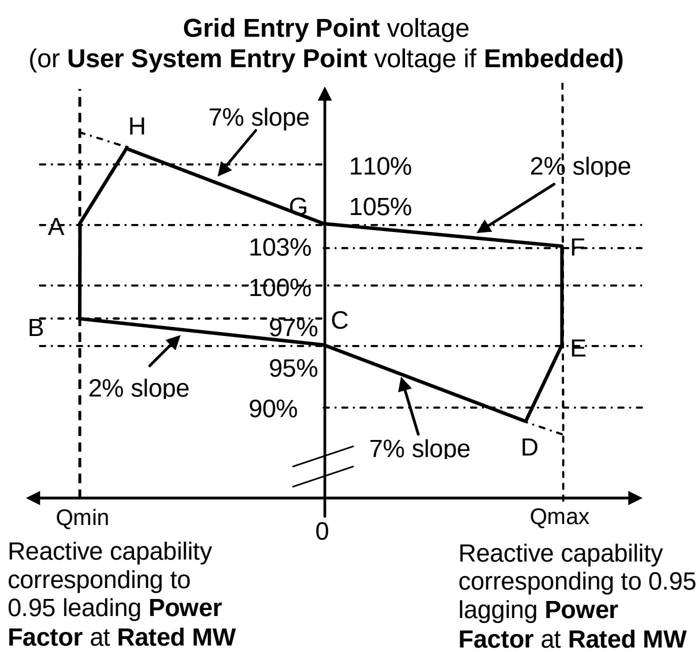


Figure B.1

The Bilateral Agreement will include any variations to the requirements in the Grid Code applicable to an individual site.

The Generator must provide National Grid with a transfer block diagram illustrating the Power Park Module voltage control scheme and include all associated parameters. This forms part of Schedule 1 of the Data Registration Code and should be included in part 3 of the User Data Library (UDL). The information will enable National Grid to review the suitability of the proposed test programme to demonstrate compliance with the Grid Code.

B.1.1 Target Voltage and Slope

The National Grid Control Centre issues voltage control instructions to all Balancing Market participants. For Power Park Modules the usual instruction is Target Voltage set point. The slope may also be varied by control instruction but is usually expected to be 4%. The procedures for Voltage Control instructions are included in Grid Code Balancing Code (BC) 2.

B.1.2 Delivery of Reactive Capability Beyond ±5% Voltage

The Grid Code requires a Reactive Capability equivalent to ±0.95 power factor usually at the Grid Entry Point or User System Entry Point if Embedded. For older wind farms, variations from this will be stated in the Bilateral Agreement. Grid Code CC.6.3.4 requires that the full Reactive Capability is capable of being delivered for voltages at the Grid Entry Point within ±5% of nominal.

Outside this range the Power Park Module must be capable of continuing to contribute to voltage control by delivering Reactive Power. However, the level of reactive power delivered may be limited by the design of the plant and apparatus. There is no low or high limit on this obligation, plant must continue to provide maximum reactive power within its design limits. The allowance for these restrictions is shown by the sloping reactive capability to the left and right of the top and bottom corners of Figure B.1 respectively (see lines A-H and D-E).

B.1.3 Transient Response

The Grid Code CC.A.7.2.3.1 sets out a number of criteria for acceptable transient voltage response. Figures B.1.3a and B.1.3b below illustrates two responses from different control philosophies that would be considered as meeting the Grid Code.

Figure B.1.3a illustrates a control scheme which employs a constant speed of response.

Figure B.1.3a

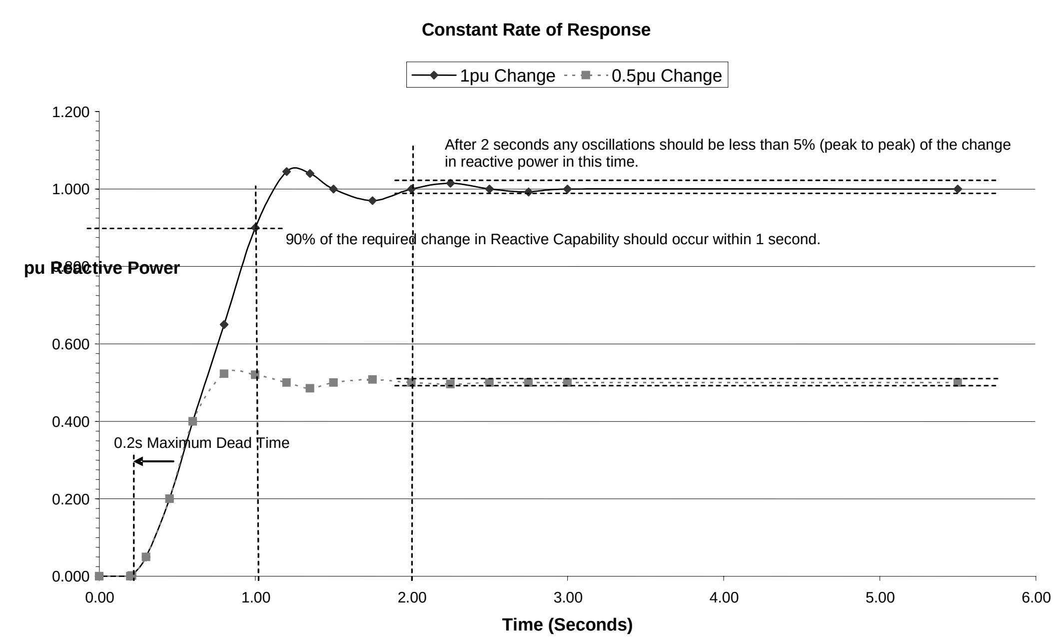
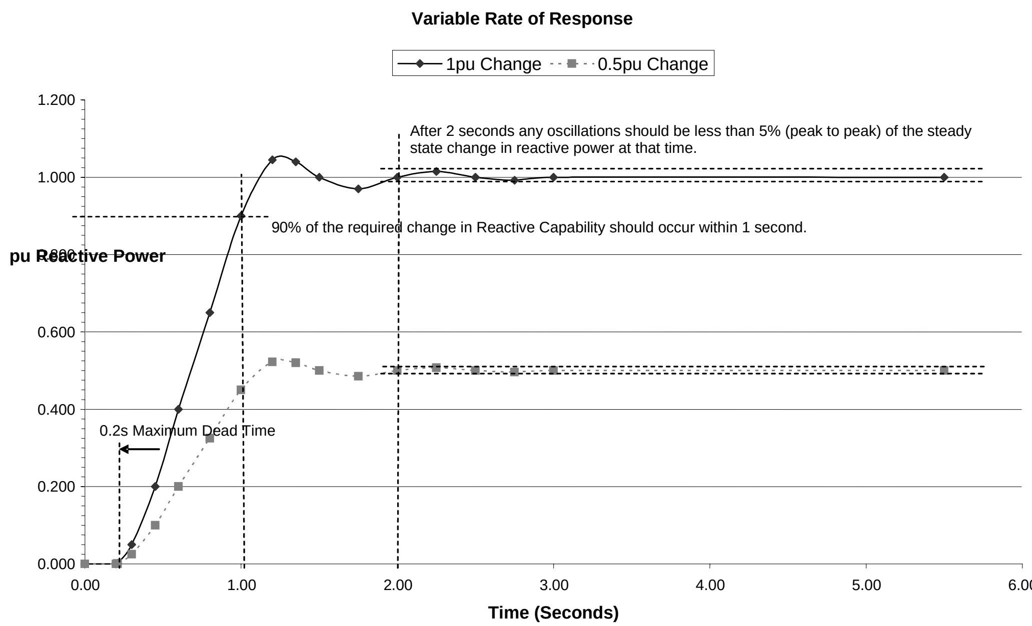


Figure B.1.3b shows a control scheme which varies the rate of response proportional to the size of the step change.

Figure B.1.3b



Both Figures B.1.3a and B.1.3b are examples of acceptable responses. Both graphs show the response to two steps, one to initiate a 1pu and the other a 0.5pu change in reactive capability. The graphs show how a variable and constant rate of change both can allow the system to achieve the objective. In both cases the dead time is less than 200ms, 90% of the reactive capability (i.e. 90% of 0.95 power factor at full load or 32.9% MVAr as measured as a proportion of rated power at any other load) is achieved in 1 second and the system settles with a maximum oscillation of 5% peak to peak, in reactive power within 2 seconds.

Note: The Grid Code states that the reactive response to a change should be "linearly increasing". For technologies where this may not be appropriate e.g. capacitor switching, provided the performance is equal to or faster than Figure B1.3b.

B.1.4 Variations in Voltage Control Requirements

The Grid Code is continually reviewed by National Grid and all Authorised Electricity Operators resulting in a document which is regularly updated. Changes in technical requirements that are considered material to Users are often related to plant Completion Dates. The aim of which is to prevent the need to retrofit older plant with new equipment.

As a result, Power Park Modules in Scotland with a completion date before the 1st of January 2007 the point of Voltage Control may be at the Power Park Unit terminals and appropriate intermediate bus bar or connection point as defined in the Bilateral Agreement.

B.2 Compliance Test Description:

National Grid requires confirmation that 90% of the full reactive capability of the Power Park Module (CC.6.3.2) can be achieved within 1 second for a sufficiently large step in voltage (CC.A.7.2.3.1). However testing this on a large Power Park Module is usually undesirable from a system perspective due to the large reactive power change driving the system voltage to extreme levels. Consequently National Grid will accept a combination of testing and computer model simulation at both the Power Park Unit and Module levels to demonstrate compliance with the Grid Code.

To reduce the work load, National Grid recommends Type Testing of the Power Park Unit by the manufacturer. The following two subsections describe the unit type tests and module tests respectively. The site tests should be performed for each new Power Park Module but the type test only needs be performed if the Power Park Units are unknown or the design or relevant parameter settings are different from previously submitted type test data.

B.2.1 Power Park Unit Type Test

It is recommended the following type tests are performed by the Power Park Unit manufacturer. However Generators should be aware that it is their responsibility to provide the necessary information specified by the Grid Code in the event that the type test data is not available from the manufacturer.

The test should be performed on a single Power Park Unit either at a manufacturer test facility or on site within a Power Park Module ensuring that other units within the Module are separately controlled. Positive and negative steps should be injected into the Power Park Unit voltage reference of sufficient magnitude to cause the full reactive absorption and generation capability to be delivered. Positive and negative steps should be injected into the Power Park Unit voltage reference at half the magnitude of the first steps.

All positive and negative steps should be undertaken at 100% Maximum Export Limit (MEL) at a time when MEL is greater than 65% of the Rated MW. If Fault Ride Through protection is fitted, it is important to ensure and demonstrate that it remains inactive.

Where the reactive capability and response is delivered for a whole Power Park Module through a central compensation device it is appropriate that some "type" testing is carried out on this device rather than the Power Park Unit. However, the magnitude of step testing may be limited by the capability of the host network.

The tests will be regarded as supporting compliance if the following requirements are met (CC.A.7.2.3.1 and CC.A.7.2.2.5):

- For the first positive and negative steps, 90% of the full reactive capability of the Power Park Unit is delivered within 1 second.
- For the second reduced size positive and negative steps, 45% of the full reactive capability of the Power Park Unit is delivered within 1 second.
- The change in reactive output should commence within 0.2s of the application of the step injection.
- Any oscillations settle, to within 5% of the final value within 2 seconds of the application of the step injection.

As part of the data required by National grid under the Grid Code Planning Code, the Generator is required to include a validated transfer block diagram model of the voltage control system. Through simulation of the above tests using the model supplied to National Grid, the Generator can contribute to validation of the model.

B.2.2 Generic Power Park Unit Type Test Procedure

The following generic procedure is provided to assist Generators in drawing up their own specific procedures for the National Grid Voltage Control Type Tests.

Test No	Step	Description	Notes
		Plant in Voltage Control at Maximum Power Output (>65% Rated MW) and Unity Power Factor	
1	1 2	• Inject +Y% step to Power Park Unit Voltage Reference • Hold until conditions stabilise • Remove the injection signal as a step • Hold until conditions stabilise	

2	3 4	• Inject -Y% step to Power Park Unit Voltage Reference • Hold until conditions stabilise • Remove the injection signal as a step • Hold until conditions stabilise	
3	5 6	• Inject +0.5Y% step to Power Park Unit Voltage Reference • Hold until conditions stabilise • Remove the injection signal as a step • Hold until conditions stabilise	
4	7 8	• Inject -0.5Y% step to Power Park Unit Voltage Reference • Hold until conditions stabilise • Remove the injection signal as a step • Hold until conditions stabilise	

Note: Y is the voltage step value required to produce a change of 100% in reactive capability. The value of Y should be recorded and added to the test results.

B.2.3 On Site Module Tests

Using a combination of the Unit Type Test and testing on the whole Power Park Module the Generator can demonstrate compliance with the transient and steady state voltage control requirements.

The Power Park Module as a whole should be subjected to a series of small positive and negative voltage step changes at the Grid Entry Point. This should be achieved by tapping the first "upstream" or higher voltage transformer outside the Power Park and by direct injection of a step change to the Power Park Module voltage reference. If the Power Park Module voltage control strategy incorporates independent local voltage control at each Power Park Unit then the Generator must identify and implement a method to simultaneously change all relevant voltage control set points or feedback signals to replicate a network voltage change.

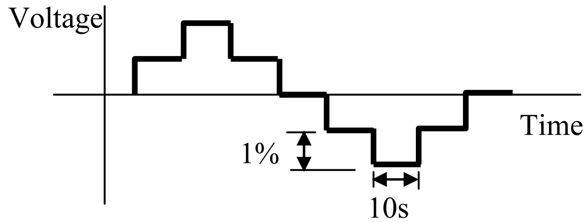
Ideally the injection signal will be software programmable with start/stop initiation via local software interface or local digital inputs. Alternatively the signals should be ±10V analogue inputs where 1 volt represents either a 0.5 % voltage change.

The signals should be available at all control nodes within the Power Park controller network, so that if appropriate and applicable, injection can take place on a single Power Park Unit or the central controller (i.e. all units simultaneously).

The testing should be performed by both methods if at all possible. This is necessary as tapping the transformer is a better demonstration of response time and includes sensor delays in the control scheme, whilst stepping the voltage reference provides a better indication of the accuracy and allows the proportionality of response to be distinctly tested.

When using an external tap changer it is suggested that the tests are conducted by applying a series of positive and negative steps at least 10 seconds apart to allow steady state to be established. This is illustrated in Figure B.2.2a below:

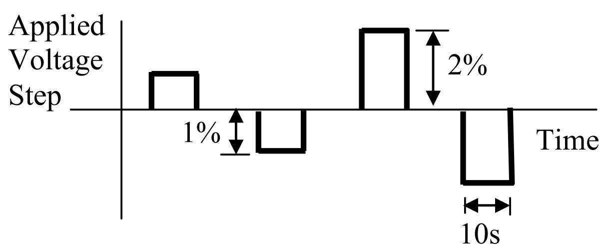
Figure B.2.2a Voltage Steps Applied by External Upstream Transformer Tapping



Where steps can be initiated using network tap changers, the Generator will need to coordinate with the host Transmission or Distribution Network Operator. Consideration should also be given to switching the associated tap changer Automatic Voltage Control (AVC) from auto to manual for the duration of the test.

For step injection into the Power Park Module voltage reference, steps of ±1% and ±2% should be applied. The injection should be maintained for 10 seconds by which time the reactive output should have achieved a steady state on the voltage slope characteristic. This is illustrated in Figure B.2.2b below.

Figure B.2.2b Steps Applied to Power Park Module Voltage Reference



All positive and negative steps should be undertaken at 100% Maximum Export Limit (MEL) at a time when MEL is greater than 65% of the Registered Capacity.

The tests will be regarded as demonstrating compliance if:

- An appropriate proportion of the full reactive capability of the Power Park Unit is delivered within 1 second. (CC.A.7.2.3.1)
- The change in reactive output commences within 0.2s of the application of the step injection (CC.A.7.2.3.1)
- Any oscillations settle, to within 5% peak to peak of the final value within 2 seconds of the application of the step injection. (CC.A.7.2.3.1)
- The final steady state reactive value according to the slope characteristic is achieved within 5 seconds of the step application. (CC.A.7.2.2.5)

As part of the data required by National grid under the Grid Code Planning Code, the Generator is required to include a validated mathematical model to represent the dynamic behaviour of the complete Power Park Module, including the response of the voltage control scheme. The Generator can validate the model by simulating the above tests using the model supplied to National Grid.

B.2.4 Suggested Power Park Module Voltage Control Test Procedure

The Module Test should be done when at all of the Power Park Units and any reactive compensation units are in service. Wind conditions (or Tidal etc.) should be such to allow power production from the Module of at least 65% Registered Capacity.

The following generic procedure is provided to assist Generators in drawing up their own site specific procedures for the National Grid Module Voltage Control Tests.

Test	Step No	Description of Injection	Notes
		Power Park Module in Voltage Control at Maximum Power Output (>65% Rated MW) and near Unity Power Factor	
1	 1 2 	• Record steady state for 10 seconds • Inject +1% step to Power Park Module Voltage Reference • Hold for at least 10 seconds • Remove injection as a step • Hold for at least 10 seconds	
2	 3 4 	• Record steady state for 10 seconds • Inject -1% step to Power Park Module Voltage Reference • Hold for at least 10 seconds • Remove injection as a step • Hold for at least 10 seconds	
3	 5 6 	• Record steady state for 10 seconds • Inject +2% step to Power Park Module Voltage Reference • Hold for at least 10 seconds • Remove injection as a step • Hold for at least 10 seconds	
4	 7 8 	• Record steady state for 10 seconds • Inject -2% step to Power Park Module Voltage Reference • Hold for at least 10 seconds • Remove injection as a step • Hold for at least 10 seconds	

Step No	Test	Description of Tapchange	Notes
		Power Park Module in Voltage Control at Maximum Power Output (>65% Rated MW) and near Unity Power Factor	
1		Record steady state for 10 seconds	
2		• Tap up 1 position on external upstream tap changer • Hold for at least 10 seconds	
3		• Tap up 1 position on external upstream tap changer i.e. up 2 positions from starting position. • Hold for at least 10 seconds	
4		• Tap down 1 position on external upstream tap changer i.e. up 1 positions from starting position. • Hold for at least 10 seconds	
5		• Tap down 1 position on external upstream tap changer i.e. at starting position. • Hold for at least 10 seconds	
6		• Tap down 1 position on external upstream tap changer i.e. down 1 positions from starting position. • Hold for at least 10 seconds	
7		• Tap down 1 position on external upstream tap changer i.e. down 2 positions from starting position. • Hold for at least 10 seconds	
8		• Tap up 1 position on external upstream tap changer i.e. down 1 positions from starting position. • Hold for at least 10 seconds	

9		• Tap up 1 position on external upstream tap changer i.e. return to starting position. • Hold for at least 10 seconds	

B.2.5 Demonstration of Slope Characteristic

The Power Park Module voltage control system is required to follow a steady state slope characteristic. This should be demonstrated by recording voltage at the controlled bus bar (usually the Grid Entry Point or User System Entry Point if Embedded) and the reactive power output at the same point over several hours. Plotting the values of Voltage against Reactive Power output should demonstrate the slope characteristic.

B.3 Additional Power System Stabiliser Testing

Additional tests are required if a Power System Stabiliser is fitted. Although the fitting of Power System Stabilisers on non synchronous plant is a rarity, one may be provided within the control system by a manufacturer or National Grid may specify the requirement in the Bilateral Agreement. The testing process outlined in this section is based largely on that employed on synchronous plant, which is believed to be comparable. However, Generators should anticipate the possibility that an alternative testing regime may be developed in discussion with National Grid.

National Grid will not permit PSS commissioning until the tuning methodologies and study results used in any PSS settings proposal have been provided to National Grid. A report on the PSS tuning should be provided along with the proposed test procedure in the User Data Library (Part 3). Based on the information submitted, National Grid will meet with the generator to discuss and agree the initial PSS settings for commissioning.

The suitability of the tuning of any PSS is checked in both the time and frequency domains. In the time domain testing is by small voltage step changes on a module basis. Comparisons are made between performance with and without the power system stabiliser in service.

For analysis in the frequency domain, a bandwidth-limited (200mHz-3Hz) random noise injection should be made to the Power Park Module voltage reference. The generator should provide a suitable band limited (200mHz-3Hz) noise source to facilitate noise injection testing. The random noise injection will be carried out with and without the PSS in service to demonstrate damping. The PSS gain should be continuously controllable (i.e. not discrete components) during testing.

The suitability of the PSS gain will also be assessed by increasing the gain in stages to 3x the proposed setting.

The tests will be regarded as supporting compliance if:

- The PSS gives improved damping following a step change in voltage.
- Any oscillations are damped out within 2 cycles
- The PSS gives improved damping of frequencies in the band 300mHz – 2Hz.
- The gain margin is adequate if there is no appreciable instability at 3x proposed gain

PSS testing is additional to the Module Voltage Control Tests.

B.3.1 Suggested Power Park Module PSS Test Procedure

The PSS Test should be done when at all of the Power Park Units and any reactive compensation units are in service. Wind conditions should be such to allow power production from the Module of at least 65% Registered Capacity.

The following generic procedure is provided to assist Generators in drawing up their own site specific procedures for the National Grid PSS Tests.

Step No	Test	Injection	Notes
		Power Park Module in Voltage Control at Maximum Power Output (>65% Rated MW) and near Unity Power Factor PSS Not in Service	
1 2 3	1	• Record steady state for 10 seconds • Inject +1% step to Power Park Module Voltage Reference and hold for at least 10 seconds • Remove step returning Power Park Module Voltage Reference to nominal and hold for at least 10 seconds	
4 5 6	2	• Record steady state for 10 seconds • Inject +2% step to Power Park Module Voltage Reference and hold for at least 10 seconds • Remove step returning Power Park Module Voltage Reference to nominal and hold for at least 10 seconds	
7 8	3	• Inject band limited (0.2-3Hz) random noise signal into voltage reference and measure frequency spectrum of Real Power. • Remove noise injection.	
9		• Switch On Power System Stabiliser	
10 11 12	4	• Record steady state for 10 seconds • Inject +1% step to Power Park Module Voltage Reference and hold for at least 10 seconds • Remove step returning Power Park Module Voltage Reference to nominal and hold for at least 10 seconds	
13 14 15	5	• Record steady state for 10 seconds • Inject +2% step to Power Park Module Voltage Reference and hold for at least 10 seconds • Remove step returning Power Park Module Voltage Reference to nominal and hold for at least 10 seconds	
16 17	6	• Inject band limited (0.2-3Hz) random noise signal into voltage reference and measure frequency spectrum of Real Power. • Remove noise injection.	
18 19	7	• Increase PSS gain at 30second intervals. i.e. x1 – x1.5 – x2 – x2.5 – x3 • Return PSS gain to initial setting	
		Repeat Module Voltage Control Tests with PSS in service.	

APPENDIX C GENERAL INFORMATION ON FREQUENCY RESPONSE ISSUES

Section 5.5 of this document describes the requirements on Users to demonstrate that the frequency controller satisfies the requirements of the Grid Code. Past experience has demonstrated that a number of issues can arise prior to and during testing. For this reason, additional information relating to the frequency controller, frequency response requirements, compliance testing and test recording arrangements are presented in this Appendix.

Appendix D provides details of the tests required for the preliminary and main frequency response tests.

C.1 Summary of Grid Code Frequency Control Requirements

The Grid Code sets out Frequency Control requirements in a number of separate places, notably the Glossary & Definitions (GD), the Connection Conditions (CC) and Balancing Code (BC) 3. This section summarises the key requirements

GD of the Grid Code defines Primary, Secondary and High frequency response including the requirement that the response is progressively delivered with increasing time.

CC.6.3.3 of the Grid Code specifies that the Power Park Module must be capable of maintaining a minimum level of active power (see Figure 2 of CC.6.3.3 (b)) in the frequency range 47Hz to 50.5Hz.

CC.6.3.7 of the Grid Code specifies the minimum frequency control capability, in particular the frequency control must be:

- Stable over the entire operating range from 47Hz to 52Hz.
- Able to contribute to controlling the frequency on an islanded network to below 52Hz.
- Capable of a frequency droop of between 3 and 5%.
- Capable of providing frequency control against a target set in the range of 49.9Hz and 50.1Hz.
- Have a frequency control dead band of less than ±0.015Hz.
- Capable of delivering a minimum level of frequency response.

BC.3 of the Grid Code specifies how plant should be operated and instructed to provide frequency response. The section also sets out the requirements on how all plant should respond to the system frequency rising above 50.4/50.5Hz, by progressively reducing output power (see below).

C.1.1 Modes of Frequency Control Operation

Balancing Code (BC) 3 of the Grid Code defines operation in Limited Frequency Sensitive Mode and Frequency Sensitive Mode.

Limited Frequency Sensitive Mode is used when not instructed by National Grid to provide Frequency Response Services. In this mode the Power Park Module is not required to provide any increase in active power output if frequency reduces below 50Hz and is only required to maintain active power output in accordance with CC.6.3.3. However, the Power Park Module is required to respond to high frequencies above 50.4Hz beyond which the Module must reduce the active power output by a minimum of 2% of output for every 0.1Hz rise above 50.4Hz (see figure C.1.1a). Should this cause power output to be forced below Designed Minimum Operating Level (DMOL) then the Power Park Module may disconnect after a time if operation is not sustainable. However for Power Park Modules, it is acceptable for individual Power Park Units to be disconnected, in order to achieve further power reductions without tripping the module.

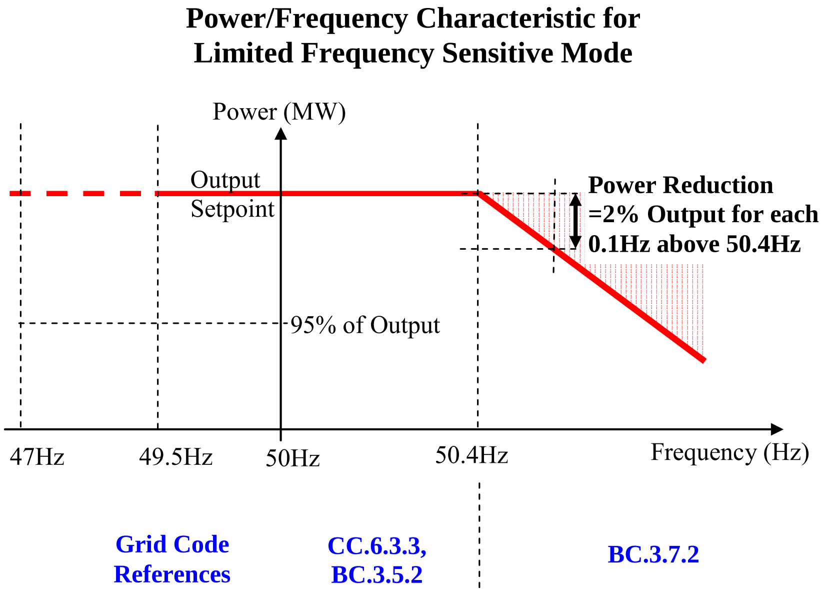


Figure C.1.1a – Limited Frequency Sensitive Mode

Frequency Sensitive Mode is used when selected to provide frequency response services. In this mode the Power Park Module must adjust the active power output in response to any frequency change according to the agreed droop characteristic (between 3-5%). For the purposes of the Mandatory Services Agreement the frequency response performance is measured in terms of the response achieved after a given duration. When system frequency exceeds 50.5Hz the requirements of Limited Frequency Sensitive Mode apply so that the Power Park Module must further reduce output by a minimum of 2% of output for every 0.1Hz rise above 50.5Hz (see figure C.1.1b). Should this cause power the output to be forced below the Designed Minimum Operating Level (DMOL) then the Power Park Module may disconnect from the system after a time if operation is not sustainable. However for Power Park Modules, it is acceptable for individual Power Park Units to be disconnected, in order to achieve further power reductions without tripping the module.

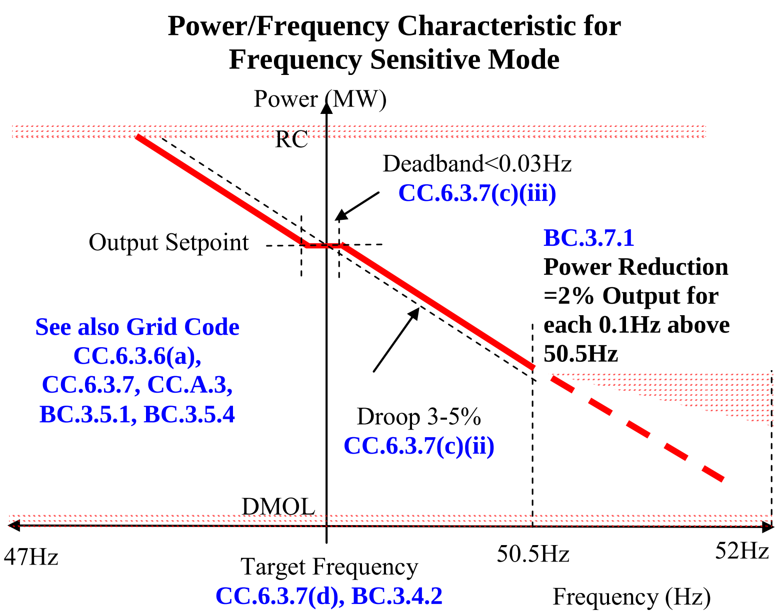


Figure C.1.1b – Frequency Sensitive Mode

C.1.2 Target Frequency

All Balancing Market Units (BMUs), irrespective of the plant type (conventional, wind, thermal or CCGT, directly Grid Connected or Embedded), are required to have the facility to set the levels of generator output power and frequency. These are generally known as Target MW and Target Frequency settings.

The National Grid Control Centre instructs all Active Balancing Market Unit to operate with the same Target Frequency, normally 50.00 Hz. In order to adjust electric clock time the System Operator may instruct Target Frequency settings of 49.95Hz or 50.05Hz. However, under exceptional circumstances, the instructed settings could be outside this range. The Grid Code requires a minimum setting range from 49.90Hz to 50.10Hz.

C.1.3 Minimum Frequency Response Requirements

All Medium and Large Power Stations with a Registered Capacity greater than 50MW are required to be capable of providing operation in Frequency Sensitive Mode over their normal operating range. The upper limit of the operating range is the Registered Capacity (RC) of the Power Park Module. The lower limit of the normal operating range is the Minimum Generation (MG) level which may be less than, but must not be more than 65% RC (although the value of MG is usually significantly less than this for intermittent power sources such as wind generation). Each Power Park Module must be capable of operating satisfactorily down to the Designed Minimum Operating Level (DMOL) as dictated by system operating conditions, although it will not be dispatched below its Minimum Generation (MG) level. The DMOL must not be more than 55% RC but is usually less in technology exploiting intermittent power sources such as wind.

The minimum frequency response requirement profile as defined in Appendix 3 of the Connection Conditions of the Grid Code is shown diagrammatically in Figure C.3.1c. This requirement only applies to Power Park Modules that have a completion date after 1 April 2005. The capability profile specifies the minimum required levels of Primary Response, Secondary Response and High Frequency Response throughout the normal plant operating range. The interpretation of these frequency response capabilities are illustrated diagrammatically in Figures **C.1.3a** & **C.1.3b**.

FIGURE C.1.3a – Interpretation of Primary and Secondary Values

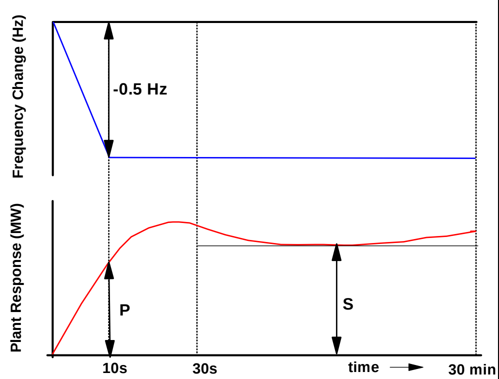
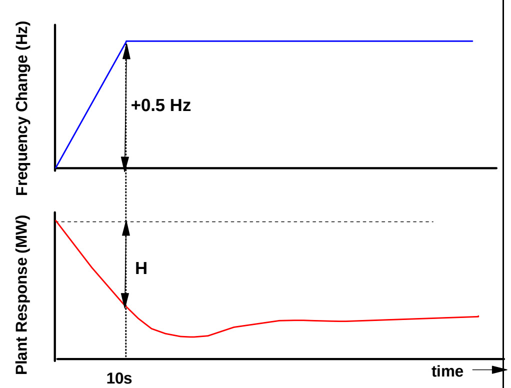
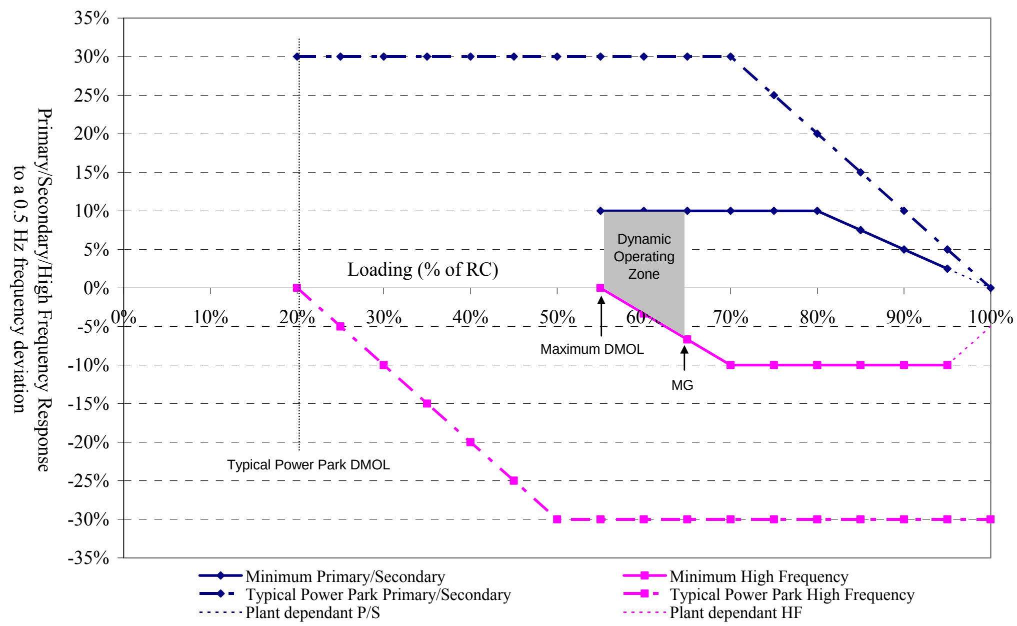


FIGURE C.1.3b– Interpretation of Primary High Frequency Response Values



Each Power Park Module must be capable of providing some response (in keeping with its specific operational characteristics) when operating from 95% to 100% of RC as illustrated by the inner dotted lines in Figure **C.1.3c**.

Figure C.1.3c – Minimum Frequency Response Requirement Profile
(for a 0.5Hz frequency change from Target Frequency)

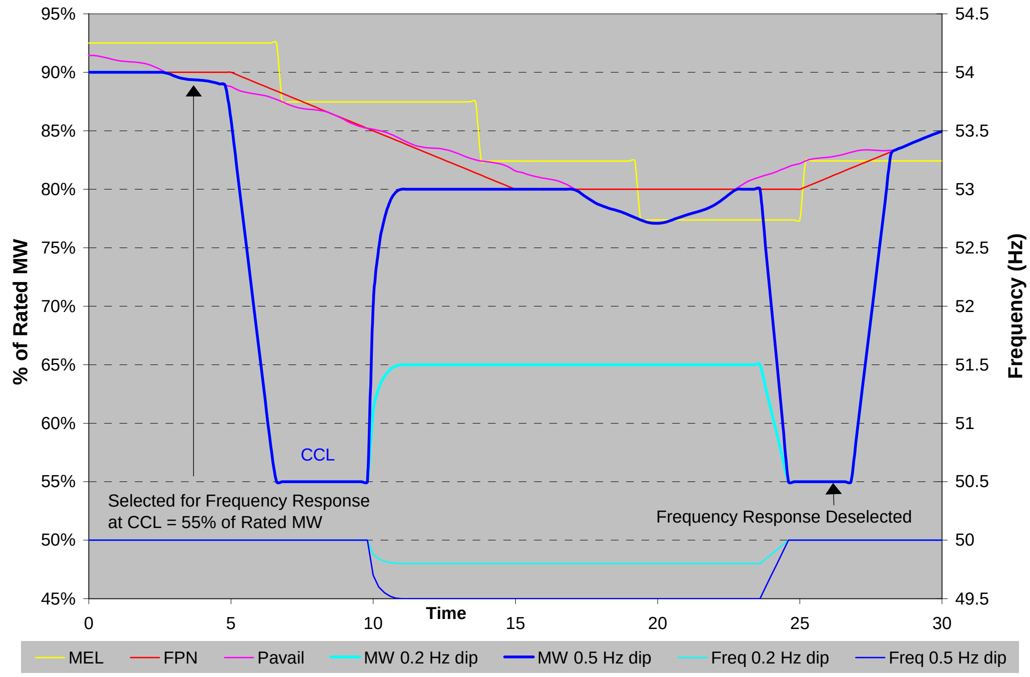


Note: The typical Power Park Module profiles above are based on a frequency droop of 3.33%. A droop of 4% would limit the response to a 0.5Hz fall in frequency to 25%.

C.2 Frequency Response from an Intermittent Power Source

Clearly the low frequency response available from a Power Park Module using an Intermittent Power Source is ultimately limited by the available power (referred to as 'Pavail'). It is expected that the low frequency response will be maintained for reducing levels of Power Source unless the 'Pavail' limits the possible response. Figure C.2 below illustrates the expected frequency response when 'Pavail' reduces and encroaches upon the available response.

Figure C.2 Expected Frequency Response with Reducing Intermittent Power Source



Notes:

The Maximum Export Limit (MEL), is declared to National Grid as a Balancing Mechanism parameter effectively equivalent to 'Pavail' which should be updated whenever the 'Pavail' changes by more than 5% or 5MW. The Final Physical Notification (FPN) is the generated power profile submitted to National Grid for a ½ hour period before gate closure. Gate closure is one hour ahead of real time. The Capped Committed Level (CCL) is the power level at which a Power Park Module operates when selected for frequency response.

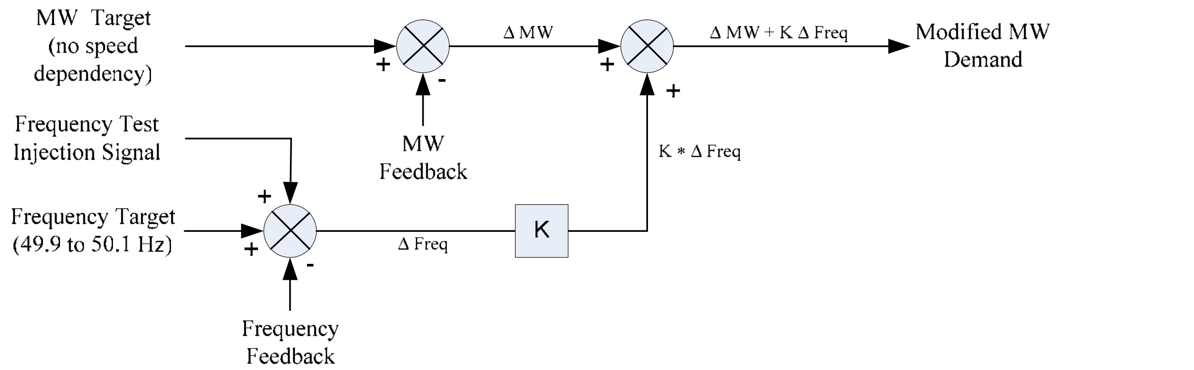
C.3 Typical Frequency Control Test Injection

A frequency injection signal is needed to undertake all frequency related capability tests. Ideally the injected signal will be directly added into the raw frequency feedback as shown in the diagram below. If the Power Park Module frequency control strategy incorporates independent local frequency control at each Power Park Unit then the Generator must identify and implement a method to simultaneously change all relevant frequency control set points or feedback signals to replicate a network frequency change.

Ideally the signal will be software programmable with start/stop initiation via local or remote software interfaces or local digital inputs. Alternatively the signals should be a ±10V analogue input where 1 volt represents 0.2 Hz frequency change.

The above signals should be available at all control nodes within the Power Park controller network, so that if appropriate and applicable, injection can take place on a single Power Park Unit or the central controller.

Figure C.3 Typical Frequency Test Injection Scheme



C.3.1 Compliance Testing Requirements

The main objectives of the frequency controller response tests are to establish the plant performance characteristics for compliance with the Grid Code technical requirements (including the validation of plant data/models). They are also required as a measured set of plant response values that will verify the response matrices for the Mandatory Services Agreement.

If a Power Park has more than one identical module, the tests will be carried out on one of the complete modules. It will be acceptable in most cases to use the test derived matrices to cover the other modules if they have the same design and control characteristics. Similarly if Frequency Control functionality is provided by identical local controllers in each Power Park Unit, "type" testing of one Power Park Unit may be acceptable as an alternative to a full module test.

In order to verify the plant behaviour it is essential that the module is tested in normal operating modes. A frequency disturbance can be simulated by injecting the required frequency variation signals to the frequency reference/feedback summing junction. An overview of the generic test sequence is described in Appendix D. The above guidelines form the basis of the tests. The test procedures are designed to be flexible to accommodate site operating conditions. However, any variations have to be agreed with National Grid.

The results obtained from reducing frequency ramps will be used to verify primary and secondary frequency response. Similarly the results obtained from increasing ramps will be used to verify the high frequency response.

Robust and stable response to islanding events can be demonstrated by injecting large and rapid frequency disturbances and observing the response. The recommended tests are illustrated in FigureD.2b.

C.4 Power Level for Frequency Control Compliance Testing

Power Park Modules using an Intermittent Power Source can not always provide the Registered Capacity (RC) indicated to National Grid by declaring a lower Maximum Export Limit. Maximum Export Limit (MEL) is a dynamic quantity based on the best estimate of available power. MEL can be constrained for many other reasons but for the purposes of this test it should only be constrained as a function of the available power source. Similarly, Stable Export Limit (SEL) is the minimum level that the Power Park Module can provide without tripping under normal Intermittent Power Source variation. These terms are used to define loading points for the tests.

Ideally, testing will be performed when the MEL is close to Registered Capacity. However, National Grid recognises that waiting for appropriate conditions can cause significant delays to the test program and therefore may allow this requirement to be relaxed, provided the MEL is no less than 65% of Registered Capacity throughout the test. National Grid reserves the right to request a repeat of the tests at up to 100% of Registered Capacity if the response is shown to be non linear or monitoring of frequency response delivery by National Grid shows deviations from the submitted frequency response data table.

In principle the maximum capacity for available low frequency response is determined by the 'deload' level from MEL. It is assumed that the low frequency response obtained from the 'deload' points tested above will not be substantially different when the MEL is at other values below Registered Capacity provided the equivalent 'deload' from MEL is used (i.e. 70% RC would be undertaken at a load point of MEL minus 30% of Registered Capacity). If this is not the case the Generator must inform National Grid and further tests may be required. Similarly the high frequency response should be similar at all MEL levels unless the response was to encroach upon the SEL.

C.5 Frequency Control Requirements not usually Tested

Verification of the Power Park Module's capability to comply with the following requirements is usually covered by design review (or type validation) rather than by test evidence. National Grid reserves the right to request testing if the design review, standard response testing or monitoring of frequency response/control delivery indicates that there may be non-compliance.

- Maintain the minimum level of active power across the full frequency range as specified in (CC6.3.3)
- Provide target frequency control with a dead band of less than ±0.015 Hz (CC6.3.7).

APPENDIX D FREQUENCY RESPONSE TEST SEQUENCE

Past experience has demonstrated that significant delays can occur during testing because of problems associated with the frequency controller setup or frequency injection method. Frequently this results in considerable lost time and additional expense for both parties. Consequently this test has been drawn up and has been shown to help in preventing such situations arising.

Typical injection locations at the frequency controller are shown in Figure C.3. In order to avoid the risk of re-testing, it is important that the injection method and the plant control are proved well in advance of the main tests by the Power Park or site contractor. A preliminary test is therefore required with details given in section D.1 below. For all tests, the target frequency selected on the generating plant is that instructed by the National Grid Control Centre. This should normally be 50.00 Hz.

D.1 Preliminary Frequency Response Testing

This should be done by performing preliminary tests when at 50% of the Power Park Units are in service and wind conditions allow production from the units of at least 50% maximum output. With the plant running at a level approximately half way between full maximum output and Designed Minimum Operating Level, the following frequency injections should be applied.

Test No	Frequency Injection	Notes
P1	**Plant in LFSM at Maximum Output** • Inject +0.8 Hz frequency rise over 30 sec • Hold until conditions stabilise • Remove the injection signal • Hold until conditions stabilise	+0.80 Hz -0.80 Hz
	Plant in FSM operating at a load point half way between Maximum Output and Designed Minimum Operating Level	
P2	• Inject 0.20Hz frequency fall as a step change • Hold until conditions stabilise • Remove the injection signal • Hold until conditions stabilise	-0.20 Hz +0.20 Hz
P3	• Inject 0.20Hz frequency rise as a step change • Hold until conditions stabilise • Remove the injection signal • Hold until conditions stabilise	+0.20 Hz -0.20 Hz
P4	• Inject 0.50Hz frequency fall as a step change • Hold until conditions stabilise • Remove the injection signal • Hold until conditions stabilise	-0.50 Hz +0.50 Hz
P5	• Inject 0.50Hz frequency rise as a step change • Hold until conditions stabilise • Remove the injection signal • Hold until conditions stabilise	+0.50 Hz -0.50 Hz

The recorded results (e.g. Freq. injected, MW, Pavail, wind speed and control signals) should be sampled at a minimum rate of 0.1 Hz to allow National Grid to assess the plant performance from the initial transients (seconds) to the final steady state conditions (which may typically take 2-15 minutes depending on the plant design). The number of turbines in service should also be stated.

The preliminary test results should be sent to National Grid for assessment at least two weeks prior to the final witnessed tests.

D.2 National Grid Witnessed Frequency Response Testing Sequence

Figures D.2a and D.2b give an overview of the ramps and step frequency injection tests required at different loading levels (i.e. MLP 6 to MLP 1). The corresponding test sequence is outlined below with the initial test establishing the maximum steady state output condition of the plant (i.e. MLP 6). This should be at least 65% of Registered Capacity with all Power Park Units in service within the Module. A full generic procedure is provided in Appendix D.3 for reference.

1. Establish Maximum Plant Capacity as Loading Point MLP6

(a) Raise load demand to confirm the maximum output level at the base settings.

(b) Record plant and ambient conditions.

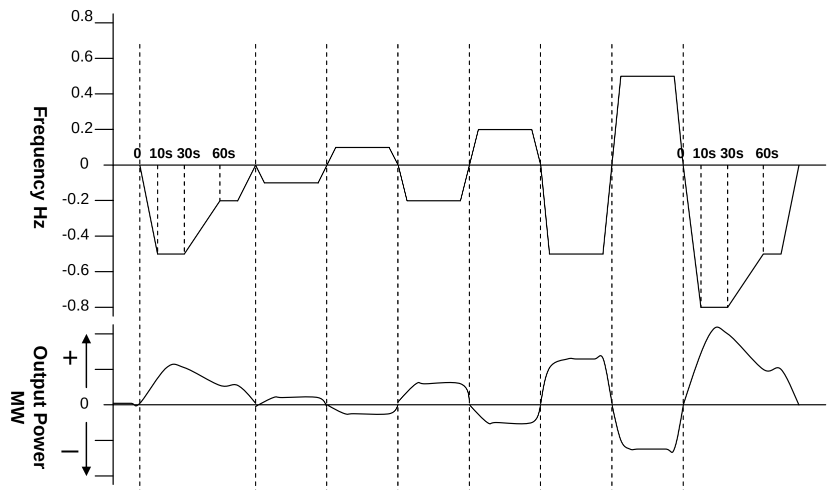
2. Response Tests at Maximum Loading Point MLP6 (>65%RC)

(a) Operate the plant at MLP 6

(b) Inject ramp/profiled frequency changes simultaneously into the Frequency load controller (i.e. Tests 1-4 in Figure D.2a) and record plant responses.

(c) Conduct test BC1-BC4 as shown in Figure D.2b to establish the robustness of the control system under simulated extreme disturbances (e.g. system islanding or system split).

Figure D.2a Frequency Response Range Tests



Load Point	LF Event Profile 1	LF Ramp -0.1Hz	HF Ramp +0.1Hz	LF Ramp -0.2Hz	HF Ramp +0.2Hz	LF Ramp -0.5Hz	HF Ramp +0.5Hz	LF Event Profile 2
MLP6			1	2	3		4	
MLP5	5			6			7	
MLP4	8	9	10	11	12	13	14	
MLP3	15						16	17
MLP2	18			19	20	21		22
MLP1	23			24	25			26

3. Response Tests at Loading Point MLP5

(a) Operate the plant at MLP5.

(b) Conduct tests 5-7 as shown in Figure D.2a and record plant responses.

4. Response Tests at Loading Point MLP4

(a) Operate the plant at loading point 4 (MLP 4).

(b) Conduct tests 8-14 as shown in Figure D.2a and record plant responses.

(c) Conduct test F-J as shown in Figure D.2b to establish the robustness of the control system under simulated extreme disturbances (e.g. system islanding or system split).

5. Response Tests at Load Point MLP3

(a) Operate the plant at MLP3.

(b) Conduct tests 15 to 17 as shown in Figure D.2a and record plant responses.

6. Response Tests at Minimum Generation MLP2

(a) Operate the plant at MLP2 (equivalent to Minimum Generation if applicable).

(b) Conduct tests 18 - 22 as shown in Figure D.2a and record plant responses.

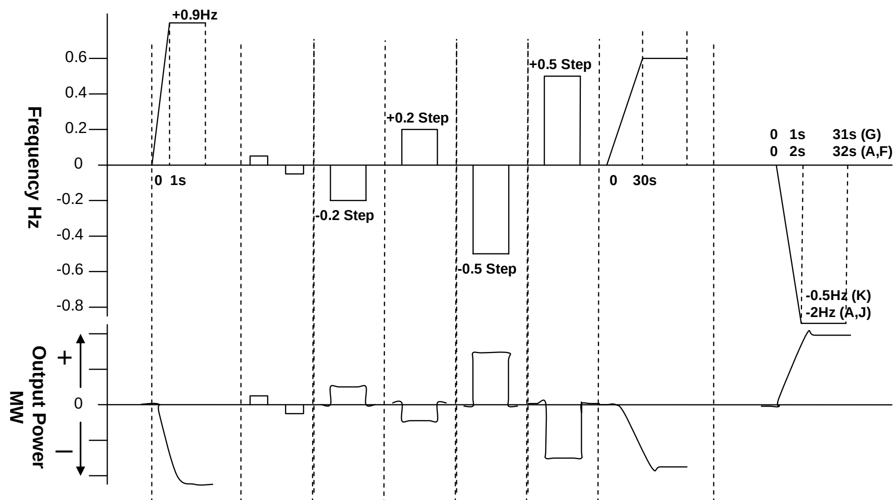
7. Response Tests at Designed Minimum Operating Level MLP1 (DMOL)

(a) Operate the plant at DMOL.

(b) Conduct tests 23 - 26 as shown in Figure D.2a and record plant responses.

(c) Conduct test K as shown in Figure D.2b.

Figure D.2b: System Islanding and Step-Response tests



Load Point	+0.9*	±0.02	-0.2	+0.2	-0.5	+0.5	+0.6	-0.5Hz -2.0Hz
MLP6	BC1						BC2	
MLP6 LFSM	BC3						BC4	
MLP5								A
MLP4		D/E	F	G	H	I		J
MLP3								
MLP2								
MLP1								K

Notes:
Tests D&E not applicable to power parks (i.e. Synchronous Systems Only)

National Grid may agree to waive the tests for data table entries 1-7 and 18-26 for Power Stations not classified as a BM Unit. However, if there is a future change in status they will be required to complete these compliance tests.

D.3 Generic National Grid Witnessed Frequency Response Test Schedule

Since the frequency response tests described above are to be arranged and conducted by the User, it is their responsibility to propose a test programme to suit their site specific requirements. A typical example of the test programme is given in this Appendix. This programme is required to be submitted to National Grid for approval at the early stage of the compliance process.

Load Points For Test		
Module Load Point 6 (Maximum Plant Capability, >65% Registered Capacity)	100% MEL	MW (MLP6)
Module Load Point 5	90% MEL	MW (MLP5)
Module Load Point 4 (Mid point of Operating Range)	(MEL + DMOL) / 2	MW (MLP4)
Module Load Point 3	DMOL + 20%	MW (MLP3)
Module Load Point 2	DMOL + 10%	MW (MLP2)
Module Load Point 1 (Design Minimum Operating Point)	DMOL	MW (MLP1)

The following example is given to demonstrate the above. Assume a wind farm has a registered Capacity of 100MW, to carry out the test wind conditions must allow for a Maximum Export Limit (MEL) of at least 65MW. If, due to wind conditions on the day, the plant can produce 70MW and the Designed Minimum Operating Level (DMOL) is 20MW them the operating points will be:

MLP6 = 100% MEL = 70MW
MLP5 = 90% MEL = 63MW
MLP4 = (MEL + DMOL) / 2 = (70 + 20) / 2 = 45MW
MLP3 = DMOL + 20 = 40MW
MLP2 = DMOL + 10 = 30MW
MLP1 = DMOL = 20MW

Initial Checks on Maximum Plant Capability at MLP6, Plant in LFSM	
Step	**Actions**
1	Increase output power demand to maximum.
2	Record plant MLP 6 condition including levels for Power Park Module MW output, ambient temperature, frequency controller signals and wind conditions.
3	Switch to Frequency Sensitive Mode of Operation.
4	MLP6 condition to be established

Injection Tests at MLP6, Plant in FSM				
Step	**Test No.**	**Action**	**Frequency Injection**	**Notes**
5	1	• Inject 0.10Hz frequency rise over 10 sec • Hold until conditions stabilise	+0.10 Hz	
6		• Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 6	-0.10 Hz	

7 8	2	• Inject 0.20Hz frequency fall over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 6	-0.20 Hz +0.20 Hz	
9 10	3	• Inject 0.20Hz frequency rise over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 6	+0.20 Hz -0.20 Hz	
11 12	4	• Inject 0.50Hz frequency rise over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 6	+0.50 Hz -0.50 Hz	
13 14	BC1	**<u>Plant in FSM</u>** • Inject +0.9* Hz frequency rise over 1 sec • Hold until conditions stabilise • Remove the injection signal • Hold until conditions stabilise at MLP 6	+0.9 Hz * -0.9 Hz	Part of functionality test for islanding CC.6.3.7 (c)(i)
15 16	BC2	**<u>Plant in FSM</u>** • Inject +0.6 Hz frequency rise over 30 sec • Hold until conditions stabilise • Remove the injection signal • Hold until conditions stabilise at MLP 6	+0.6 Hz -0.6 Hz	Part of functionality test for BC.3.7.1
Switch to Limited Frequency Sensitive Mode				
17 18	BC3	**<u>Plant in LFSM</u>** • Inject +0.9* Hz frequency rise over 1 sec • Hold until conditions stabilise • Remove the injection signal • Hold until conditions stabilise at MLP 6	+0.9* Hz -0.9* Hz	Part of functionality test for islanding CC.6.3.7 (c)(i)
19 20	BC4	**<u>Plant in LFSM</u>** • Inject +0.6 Hz frequency rise over 30 sec • Hold until conditions stabilise • Remove the injection signal • Hold until conditions stabilise at MLP 6	+0.6 Hz -0.6 Hz	Part of functionality test for BC.3.7.2

*0.9Hz is needed to take an initial output 65% to a final output of 20%. If the initial output was not 65% and the DMOL is not 20% then the injected step should be adjusted accordingly as shown in the example given below

Initial Output	65%
DMOL	20%
Frequency Controller Droop	4%

Frequency to be injected = (0.65-0.20)x0.04x50 = 0.9Hz

Injection Tests at MLP 5, Plant in FSM				
21 22 23	5	• Inject 0.50Hz frequency fall over 10 sec • Hold for 20 sec • Inject 0.30Hz frequency rise over 30 sec • Hold until conditions stabilise • Remove the injection signal Hz over 10 sec • Hold until conditions stabilise at MLP 5	-0.50 Hz +0.30 Hz	
24 25	6	• Inject 0.20Hz frequency fall over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 5	-0.20 Hz +0.20 Hz	

26 27	7	• Inject 0.50Hz frequency rise over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 5	+0.50 Hz -0.50 Hz	
28 29	A	• Inject 2.0Hz/sec frequency fall over 2 sec • Hold for 30 sec • Remove the injection signal • Hold until conditions stabilise at MLP 5	-2.0 Hz +2.0 Hz	To assess plant performance under islanding and system split Conditions

Injection Tests at MLP 4, Plant in FSM				
30 31 32	8	• Inject 0.50Hz frequency fall over 10 sec • Hold for 20 sec • Inject 0.30Hz frequency rise over 30 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 4	-0.50 Hz +0.30 Hz +0.20 Hz	
33 34	9	• Inject 0.10Hz frequency fall over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 4	-0.10 Hz +0.10 Hz	
35 36	10	• Inject 0.10Hz frequency rise over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 4	+0.10 Hz -0.10 Hz	
37 38	11	• Inject 0.20Hz frequency fall over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 4	-0.20 Hz +0.20 Hz	
39 40	12	• Inject 0.20Hz frequency rise over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 4	+0.20 Hz -0.20 Hz	
41 42	13	• Inject 0.50Hz frequency fall over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 4	-0.50 Hz +0.50 Hz	
43 44	14	• Inject 0.50Hz frequency rise over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 4	+0.50 Hz -0.50 Hz	
45 46	F	• Inject 0.20Hz frequency fall as a step change • Hold until conditions stabilise • Remove the injection signal • Hold until conditions stabilise at MLP 4	-0.20 Hz +0.20 Hz	To assess step response characteristics of plant
47 48	G	• Inject 0.20Hz frequency rise as a step change • Hold until conditions stabilise • Remove the injection signal • Hold until conditions stabilise at MLP 4	+0.20 Hz -0.20 Hz	To assess step response characteristics of plant
49	H	• Inject 0.50Hz frequency fall as a step change • Hold until conditions stabilise	-0.50 Hz	To assess step response

50		• Remove the injection signal • Hold until conditions stabilise at MLP 4	+0.50 Hz	characteristics of plant
51 52	I	• Inject 0.50Hz frequency rise as a step change • Hold until conditions stabilise • Remove the injection signal • Hold until conditions stabilise at MLP 4	+0.50 Hz -0.50 Hz	To assess step response characteristics of plant
53 54	J	• Inject 2.0Hz frequency fall over 2 sec • Hold for 30 sec • Remove the injection signal • Hold until conditions stabilise at OLP	-2.0 Hz +2.0 Hz	To assess plant performance under islanding and system split conditions

Injection Tests at MLP 3, Plant in FSM				
55 56 57	15	• Inject 0.50Hz frequency fall over 10 sec • Hold for 20 sec • Inject 0.30Hz frequency rise over 30 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 3	-0.50 Hz +0.30 Hz +0.20 Hz	
58 59	16	• Inject 0.50Hz frequency rise over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 3	+0.50 Hz -0.50 Hz	
60 61 62	17	• Inject 0.80Hz frequency fall over 10 sec • Hold for 20 sec. • Inject 0.30Hz frequency rise over 30 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 3	-0.80 Hz +0.30 Hz +0.50 Hz	

Injection Tests at MLP2, Plant in FSM				
63 64 65	18	• Inject 0.50Hz frequency fall over 10 sec • Hold for 20 sec • Inject 0.30Hz frequency rise over 30 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 2	-0.50 Hz +0.30 Hz +0.20 Hz	
66 67	19	• Inject 0.20Hz frequency fall over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 2	-0.20 Hz +0.20 Hz	
68 69	20	• Inject 0.20Hz frequency rise over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 2	+0.20 Hz -0.20 Hz	
70 71	21	• Inject 0.50Hz frequency fall over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 2	-0.50 Hz +0.50 Hz	
72 73	22	• Inject 0.80Hz frequency fall over 10 sec • Hold for 20 sec • Inject 0.30Hz frequency rise over 30 sec • Hold until conditions stabilise	-0.80 Hz +0.30 Hz	

74		• Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 2	+0.50 Hz	

Injection Tests at MLP 1, Plant in FSM				
75 76 77	23	• Inject 0.50Hz frequency fall over 10 sec • Hold for 20 sec • Inject 0.30Hz frequency rise over 30 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 1	-0.50 Hz +0.30 Hz +0.20 Hz	
78 79	24	• Inject 0.20Hz frequency fall over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 1	-0.20 Hz +0.20 Hz	
80 81	25	• Inject 0.20Hz frequency rise over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 1	+0.20 Hz -0.20 Hz	
82 83 84	26	• Inject 0.80Hz frequency fall over 10 sec • Hold for 20 sec • Inject 0.30Hz frequency rise over 30 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 1	-0.80 Hz +0.30 Hz +0.50 Hz	
85 86	K	• Inject 0.5Hz frequency fall over 1 sec • Hold for 30 sec • Remove the injection signal • Hold until conditions stabilise at MLP	-0.5 Hz +0.5 Hz	To assess plant performance under islanding and system split conditions

APPENDIX E FAULT RIDE THROUGH TESTING

E.1 Summary of Grid Code Requirements

This section details the requirements for all Power Park Modules from this point in time forward. It does not cover the historical position of the developing requirements, which can be found in CC.6.3.15 of the Grid Code.

The Grid Code ‘fault ride through’ requirements apply to all faults on the 275kV or 400kV GB Transmission System. The requirements vary depending on the type of fault and the Supergrid voltage profile (duration of fault or voltage dip).

These requirements can be conveniently referred to in the context of two separate fault modes (A & B, which are respectively covered by CC.6.3.15 (a) and CC.6.3.15 (b) of the Grid Code)

E.1.1 ‘Mode A’ Requirements - first 140msec of a fault

‘Mode A’ refers to the first 140msec of three-phase, phase to phase, two-phase to earth or single-phase to earth faults.

Throughout this period the Power Park Module is required to remain transiently stable and connected for all Supergrid phase voltages down to a minimum of 0%. It should also generate the maximum possible reactive current without exceeding the transient rating limit of the Power Park Module or any constituent element.

Within 0.5 seconds, following fault clearance and restoration of the Supergrid voltage to at least 90% of nominal, the Power Park Module must restore the Active Power output to at least 90% of the level available immediately before the fault.

Note: It is anticipated that in achieving this response the control system may be under damped. This will be considered acceptable provided any oscillations decay in a suitably short period and that whilst the oscillations are present the average power delivered corresponds with the levels required were the oscillations not present.

Although the voltage will begin to recover upon fault clearance (within 140msec) it may not necessarily reach 90% voltage within the 140msec period as illustrated in the Appendix of the Connection Conditions (CC.A.4.2). If the Supergrid Voltage has not restored to at least 90% within 140msec then the remaining fault period can be assumed to have a balanced retained voltage and that ‘Mode B’ requirements will then apply in the remaining fault period.

E.1.2 ‘Mode B’ Requirements - fault period following the first 140msec

‘Mode B’ refers to a period of balanced voltage reduction due to power system transients caused by remote faults or the period following clearance of Supergrid faults where the voltage remains reduced for a period.

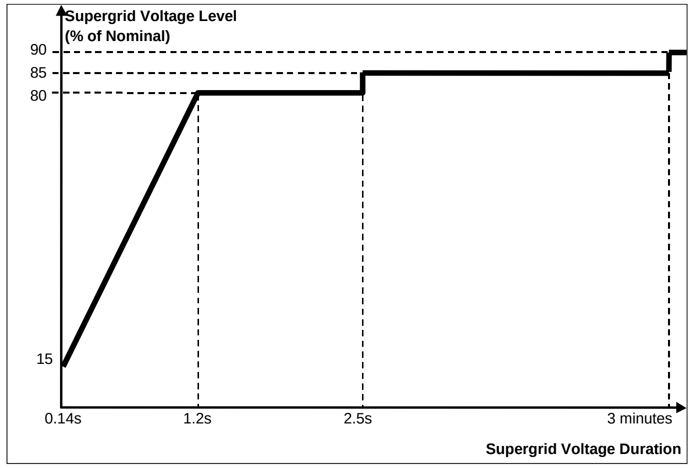
Throughout this period the Power Park Module is required to remain transiently stable and connected. It must maintain Active Power at least in proportion to the retained balanced Supergrid Voltage and generate the maximum possible reactive current without exceeding the transient rating limit of the Power Park Module or any constituent element.

Within 1 second, following fault clearance and restoration of the Supergrid voltage to at least 90% of nominal, the Power Park Module must restore the Active Power output to at least 90% of the level available immediately before the fault. Once again, appropriately damped active power oscillations shall be acceptable provided the total energy delivered during the period of the oscillation shall be 90% or more (see note above).

May 2007 - Issue 2 Draft 2

The worst case duration for which Mode B requirements apply can be calculated by taking the lowest voltage occurring after the first 140msec and finding where it intersects the profile illustrated in CC.A.4.3. For convenience the profile is replicated in Figure E.1.2 below.

Figure E.1.2 -
Supergrid Voltage dips greater than 140msec in duration



E.1.3 Requirements for Induction Generators

Induction Generators and Doubly Fed Induction Generators typically deliver large amounts of lagging reactive current on application of a fault, which is frequently followed by the delivery of leading current. There after, the current level is dependant upon the technology used and its configuration. For these types of machines, this type of response will be considered on a case by case basis and is likely to be accepted provided:

1. The control system does not introduce extended delays
2. Limit the lagging current contribution to less than the equipment capabilities.

E.2 Fault Ride Through – Level 1 and 2 Testing

The manufacturer may demonstrate fault ride through using tests appropriate to the facilities available. However a sufficiently large selection of results for balanced and unbalanced faults of varying duration must be provided to replicate the Mode A and B requirements summarised in Appendix E.1.

Consideration should be given to ensure the tests are severe enough to provide a benchmark against which the studies in section 4.5 will give successful results.

National Grid expects the tests to replicate each fault type (3-phase, phase-phase, two-phase to earth and single-phase to earth) with varying magnitudes. The tests should illustrate any changes in characteristics or internal operating modes that depend upon fault severity. For example DFIG wind turbines that utilise crowbar or similar devices should implement tests that illustrate the crowbar inception operating level and any consequential Power Park Unit characteristics, such as active and reactive power fault contribution and power recovery characteristic.

Tests should be repeated at a number of operating points. For example:

- Rated MW
- 70% MEL when MEL is greater than or equal to Rated MW
- SEL when SEL is no greater than DMOL.

E.3 Level 2 – Power Cycling Test (Type Validation Test 4)

This test only applies to Power Park Units that have previously established that the electrical interface is capable of riding through simulated Supergrid faults in a suitable test circuit (see type validation level 2 tests in section 5.6).

This test is designed to demonstrate that the remaining mechanical plant is capable of managing the consequences of the power perturbation (MW output reduction) occurring during faults and still be able to deliver the power recovery performance required (CC.6.3.15). The test should be performed using a complete Power Park Unit including the power capture components.

However, not all technologies will be able to implement this test, consequently this compliance option is not available and other compliance routes must be pursued (see level 1 or 3 of section 5.6).

Figure E.3 below shows an example of how the power cycling test may be implemented in a DFIG based wind turbine. In this arrangement it is possible to replicate the MW dip, caused by a grid fault, by injecting step changes to the MW or torque demand in the converter control system.

This MW reduction in electrical output, will demonstrate the control system's response to continued power capture at the turbine blades without a corresponding export at the generator terminals. Removing this signal allows the control system to recover in the normal way to demonstrate the power recovery characteristics. It may also be necessary to ensure other FRT control functions are also triggered at the same time as implementing this MW reduction injection

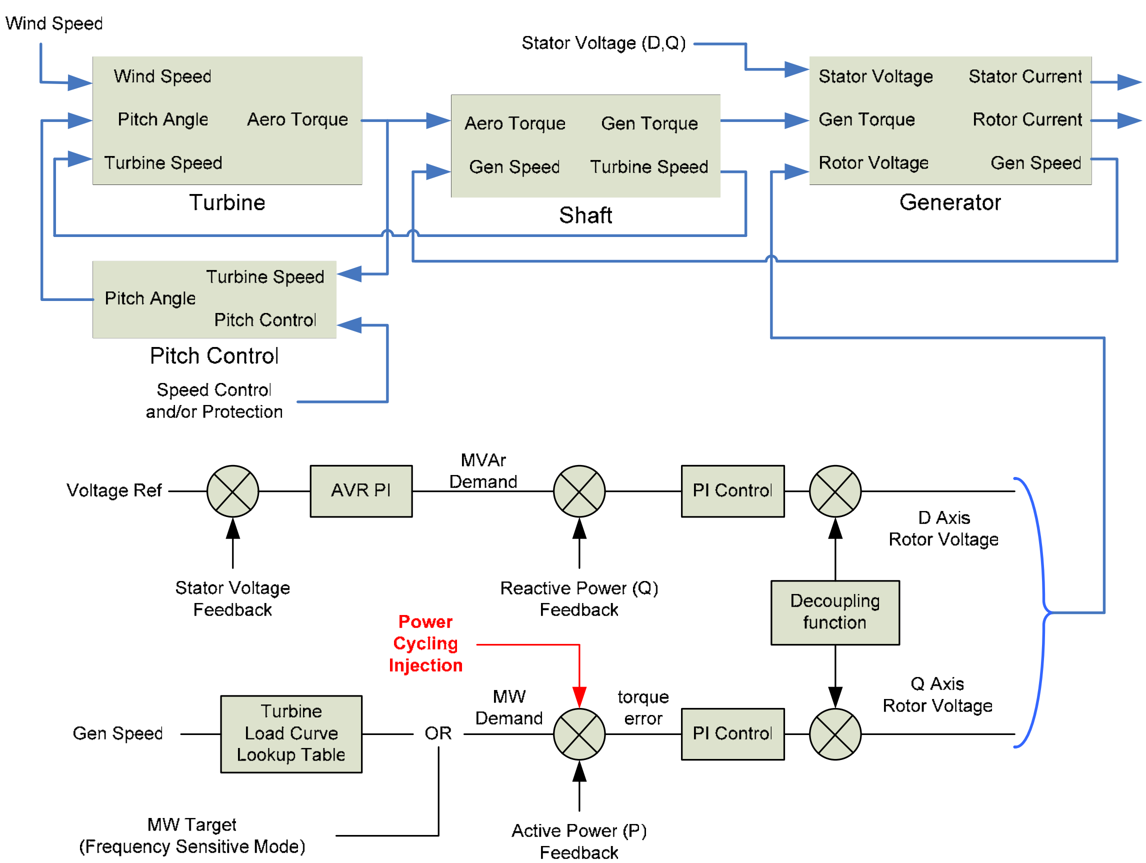


Figure E.3 Power Cycling Injection Example (DFIG Wind Turbine)

E.3.1 MW Target Reduction Injection Signal

A MW Target Reduction Injection Signal is needed to undertake the power cycling test. For Full Converter and DFIG (Doubly Fed Induction Generators) the signal will be injected directly into converter to demand a reduction in electrical output power but not the mechanical system which will be required to respond accordingly to the resulting speed change. Conversely for standard induction generators the signal will be injected into governor to request a reduction in output power.

Ideally the signal will be software programmable with start/stop initiation via local or remote software interfaces or local digital inputs. Alternatively the signals should be a ±10V analogue input where 1 volt represents 10% power change.

E.4 Generic Type Test Procedure

E.4.1 Fault Ride Through (Levels 1 and 2)

Levels 1 and 2 involve applying simulated fault conditions, by applying short circuits, into known impedances to real systems. Compliance with fault ride through may be demonstrated by test conditions which are different to those specified in this sub section and different to the requirements specified in the grid code, provided:

1. The test conditions are more severe.
2. They encompass all of the various fault scenarios covered by the grid code.
3. They can be used in conjunction with the studies to demonstrate compliance.

A test program is listed here as a suitable example.

The table below summarises the studies described in section 4.5. The test evidence needs to correlate with the study evidence to demonstrate compliance.

% Retained Supergrid Voltage	3ph	Ph – ph	2ph – E	1ph – E	Grid Code Ref	Power Recovery
0	0.14s	0.14s	0.14s	0.14s	CC6.3.15a	In 0.5 second post fault
30	0.384				CC6.3.15b Including Figure 5	In 1 second post fault
50*	0.71s					
80	2.5s					
85	180s					
*50% retained voltage is to give an indication of being able to meet the slope from 0.14s to 1.2s on the voltage – time trace in CC6.3.15b Figure 5 for balanced faults.						

Figure E.4.1 – Fault Ride Through – Type Tests

The purpose of the tests is to characterise the Power Park Unit such that its limit of operation for retained voltage (at the terminals of the Power Park Unit) is known. At the end of the test the results should indicate the level of voltage depression the unit can with stand for the times specified. Whilst the volts are depressed the Power Park Unit should deliver power in the same proportion as the volts and then recover once volts are restored.

Ideally Power Park Units will achieve the voltage levels and durations listed in table E.4.1 as this would indicate that the unit is fully compliant without the need for the study evidence in section 4.5. However these levels are unlikely to occur at the Power Park Unit terminals in practice because of the impedance between the fault location and the Power Park Unit. Consequently, increased test voltage levels above those specified are typically acceptable for most circumstances but require further study evidence (on a case by case basis) to demonstrate that the levels which occur at the a particular Power Park are greater than those which the Power Park Units are capable of riding through.

The results should demonstrate the Power Park Unit can survive at 0% retained volts for 140ms or if the unit can not operate down to zero, minimum retained volts the unit can operate at for 140ms. The unit must be capable of recovering once the fault is removed. This should be determined for all fault modes: 3 phase, phase to phase and single and two phases to earth faults.

In addition the results should characterise, at appropriate points, the fault contribution for Mode B voltage depression after a three phase fault. To do this the voltage at the Power Park Unit terminals should be reduced to the voltages specified below (in separate tests):

1. 30% volts for a period of 384ms
2. 50% volts for a period of 710ms
3. 80% volts for a period of 2.5 secs
4. 85% volts for a period of 180 secs

At the end of each of these tests the voltage should be returned to 90% until conditions have stabilised or for a minimum period of 180 seconds.

Power Park Unit designs which incorporate features such as crowbar thyristor protection to enable them to meet the fault ride through requirements, should additionally indicate for each test whether the crowbar or other protection modes were active.

The tests should be performed on a single Power Park Unit (or in the case of Level 2, Power Park Unit's electrical system) using the test circuit shown below.

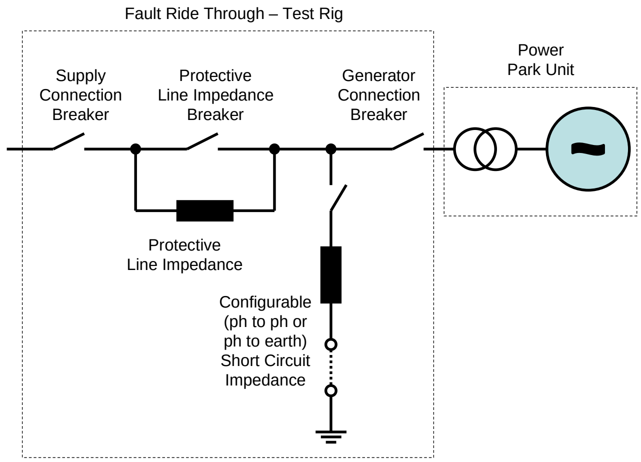


Figure E.4.1

Test No	Step	Description	Notes
1		• Operate the Power Park Unit (PPU) at nominal volts and maximum rated output or for Level 1 >65% rated output. • Apply a 3ph short reducing the volts to 0% • Hold the voltage at 0% for 140ms • Allow the voltage to recover to nominal volts • Hold until conditions stabilise • If the unit passes this test proceed to test 3 otherwise proceed to test 2	Mode A
2		• Repeat test 1 to determine the minimum retained volts until the unit can operate at for a period of 140ms	Mode A
3		• Operate the Power Park Unit (PPU) at nominal volts and maximum rated output or for Level 1 >65% rated output. • Apply a 1ph to earth short circuit reducing the volts to 0% • Hold the voltage at 0% for 140ms • Allow the voltage to recover to nominal volts • Hold until conditions stabilise • If the unit passes this test proceed to test 5 otherwise proceed to test 4	Mode A
4		• Repeat test 3 to determine the minimum retained volts the unit can operate at for a period of 140ms	Mode A
5		• Operate the Power Park Unit (PPU) at nominal volts and maximum rated output or for Level 1 >65% rated output. • Apply a 2ph to earth short circuit reducing the volts to 0% • Hold the voltage at 0% for 140ms • Allow the voltage to recover to nominal volts • Hold until conditions stabilise • If the unit passes this test proceed to test 7 otherwise proceed to test 6	Mode A
6		• Repeat test 5 to determine the minimum retained volts the unit can operate at for a period of 140ms	Mode A

7		• Operate the Power Park Unit (PPU) at nominal volts and maximum rated output or for Level 1 >65% rated output. • Apply a phase to phase short circuit reducing the volts to 0% • Hold the voltage at 0% for 140ms • Allow the voltage to recover to nominal volts • Hold until conditions stabilise • If the unit passes this test proceed to test 9 otherwise proceed to test 8	Mode A
8		• Repeat test 7 to determine the minimum retained volts the unit can operate at for a period of 140ms	Mode A
11		• Operate the Power Park Unit (PPU) at nominal volts and maximum rated output or for Level 1 >65% rated output. • Apply a reduction in 3ph voltage to 30% • Hold the voltage at 30% for 384ms • Increase the voltage to 90% • Hold until conditions stabilise or a minimum of 3 minutes	Mode B
12		• Operate the Power Park Unit (PPU) at nominal volts and maximum rated output or for Level 1 >65% rated output. • Apply a reduction in 3ph voltage to 50% • Hold the voltage at 50% for 710ms • Increase the voltage to 90% • Hold until conditions stabilise or a minimum of 3 minutes	Mode B
13		• Operate the Power Park Unit (PPU) at nominal volts and maximum rated output or for Level 1 >65% rated output. • Apply a reduction in 3ph voltage to 80% • Hold the voltage at 80% for 2.5 secs • Increase the voltage to 90% • Hold until conditions stabilise or a minimum of 3 minutes	Mode B
14		• Operate the Power Park Unit (PPU) at nominal volts and maximum rated output or for Level 1 >65% rated output. • Apply a reduction in 3ph voltage to 85% • Hold the voltage at 85% for 180 secs • Increase the voltage to 90% • Hold until conditions stabilise or a minimum of 3 minutes	Mode B

E.4.2 Power Cycling Test (Level 2 Only)

To synthesise a grid fault the electrical control system must, if possible, reduce the electrical power to the target levels given in the following table in less than 40msec, hold at the reduced value for the period defined and then allow the normal power recovery scheme to restore the pre-test active power.

Profile	Retained Supergrid Voltage	Target Power (< 40 msec)	Minimum Duration
Mode A	0 pu	0 pu	140 msec + ½ actual time taken to reach target
Mode B	0.3 pu	0.3 pu *	384 msec + ½ actual time taken to reach target
Mode B	0.5 pu	0.5 pu *	710 msec + ½ actual time taken to reach target
Mode B	0.65 pu	0.65 pu *	955 msec + ½ actual time taken to reach target
Mode B	0.8 pu	0.8 pu *	2.5 seconds
Mode B	0.85 pu	0.85 pu *	3 minutes

*Target Power Calculation
For the purposes of type validation the target power level must be as listed in the table above. The power levels and durations specified should be suitable for both Full Converter and DFIG (Doubly Fed Induction Generators) based technologies, where the reduction in power signal can be injected into electrical control system.

However with standard IG (Induction Generator) based technologies the signal must be injected into the power capture systems governor and alternative values of power duration will be needed. Manufacturers of IG based technologies should contact National Grid to agree appropriate levels and durations.

The power levels listed, make no allowance for fault contribution, network impedance or local loads, but are considered the minimum requirement for type validation of the mechanical part of the system. If the test is being performed for a specific site, it may be preferable to calculate alternative active power levels that reflect a better estimate of the active power during the Supergrid voltage dip. The results obtained in Study 3.1 can be used to determine these target power levels (see section 4.5).

The following generic procedure is provided to assist Generators in drawing up their own specific procedures for the test.

Test No	Step	Description	Notes
1	1 2	• Inject -100% step in power output • Hold for a period 140ms + ½ actual time taken to reach target • Remove the injection signal as a step • Hold until conditions stabilise	
2	3 4	• Inject -70% step in power output • Hold for a period 384ms + ½ actual time taken to reach target • Remove the injection signal as a step • Hold until conditions stabilise	
3	5 6	• Inject -50% step in power output • Hold for a period 710ms + ½ actual time taken to reach target • Remove the injection signal as a step • Hold until conditions stabilise	
4	7 8	• Inject -35% step in power output • Hold for a period 955ms + ½ actual time taken to reach target • Remove the injection signal as a step • Hold until conditions stabilise	
5	9 10	• Inject -20% step in power output • Hold for a period 2.5s + ½ actual time taken to reach target • Remove the injection signal as a step • Hold until conditions stabilise	
6	11 12	• Inject -15% step in power output • Hold for a period 3minutes • Remove the injection signal as a step	

		• Hold until conditions stabilise	

APPENDIX F SIMPLIFIED METHOD OF PROVIDING FAULT RIDE THROUGH STUDY EVIDENCE

The following notes provide further guidance in relation to simplified fault ride through studies associated with Study 3 in section 4. The studies should be carried out with only 50% or less of the Power Park Units running,

The next two subsections, describe a simplified method of determining the fault ride through capability where the Point of Connection is not the Supergrid. This method relies on substituting the network between the Supergrid and Point of Connection with an equivalent impedance. A reasonable value for the equivalent impedance needs to be determined. The worst case scenario will be the minimum impedance. This can be derived from the maximum fault level.

In some cases however, the maximum fault level may include contributions from other generation embedded between the Point of Connection and the Supergrid. Consequently the apparent impedance derived by the maximum fault level may be lower than the actual impedance. This will provide a worst case scenario. The maximum fault level data at the point of connection is readily available and is therefore a reasonable place to start. If this conservative impedance estimate is too arduous more detailed work will be needed to obtain a better impedance estimate.

For Power Parks with a point of connection to the Supergrid, the technique described below is still appropriate however the equivalent impedance (described above) is removed.

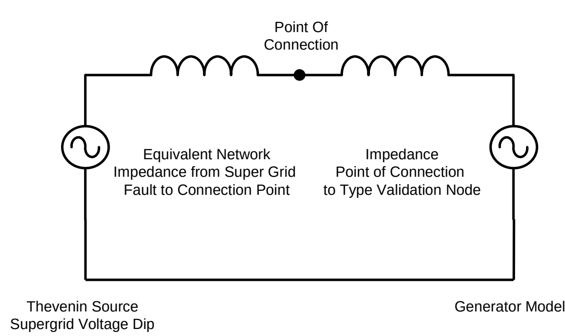
F.1 Positive Sequence Studies

The simplified positive sequence network below will generally be accepted as satisfying the 'pps' aspect of study 3.1 and study 3.2.

In this conservative and simplified case, the network beyond the point of connection is represented by, a controlled Thevenin source and equivalent impedance. The equivalent impedance is derived from the maximum fault level at the point of connection.

The type validation tests were based on benchmarking the Power Park Unit at a node selected by the manufacturer. The impedance between the point of connection and the 'type validation node' must reflect the equivalent aggregated impedance of the Power Park between the point of connection and the same node.

The remaining impedance is the impedance between the 'type validation node' and the point at which the model representation begins (model interface node). In some cases the type validation node and the model interface node will be the same point and this impedance will not be included.

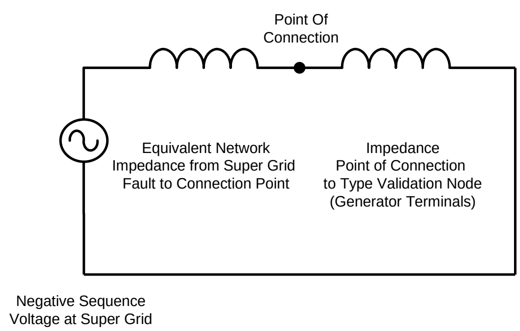


This simplified network can be implemented in a power system analysis package of the Developers choice using the voltage dips specified in Studies 3.1 & 3.2. The results at node 'A' are then compared to the type validation results to confirm ride through capability. The validity of the generator model's contribution to the retained voltage also needs to be confirmed by ensuring that the contribution at 'B' is comparable with the results obtained during the type validation tests for the equivalent profile at 'A'.

F.2 Negative Sequence Studies

Similarly the simplified negative sequence network below will generally be accepted as satisfying the 'nps' aspect of study 3.1 and study 3.3.

The negative sequence network is identical to the positive sequence network except that the generator model and the impedance between the 'type validation node' and the model interface node are replaced with an equivalent negative sequence estimate obtained during the type validation tests.



Solving the load flow for the above network using a voltage source corresponding to the negative sequence magnitude at the Supergrid results in a negative sequence voltage estimate at the type validation node ('A'). The results at node 'A' are then compared to the type validation results to confirm ride through capability.

In the event that the type validation tests show that there is no single equivalent negative sequence impedance then the type validation will record a family of impedances equating to retained negative sequence voltages at the type validation node. The negative sequence studies will then be run iteratively and the impedance value updated until reasonable convergence is obtained.

APPENDIX G POWER QUALITY REQUIREMENTS

For Power Parks that are to be connected to the GB Transmission System, the harmonic distortion and voltage fluctuation (flicker) limits are set out in accordance with the Grid Code. The Transmission Owner is required to meet the relevant terms of the Grid Code.

With respect to harmonics, the Grid Code CC.6.1.5(a) requires that the Electromagnetic Compatibility Levels for harmonic distortion on the Transmission System from all non-linear sources under both planned outage and fault outage conditions, (unless abnormal conditions prevail) shall comply with the compatibility levels given in Appendix A of Engineering Recommendation G5/4. The Grid Code further requires that the planning criteria contained within Engineering Recommendation G5/4 be applied for the connection of non-linear sources to the Transmission System, which result in harmonic limits being specified for these sources in the relevant Bilateral Agreement.

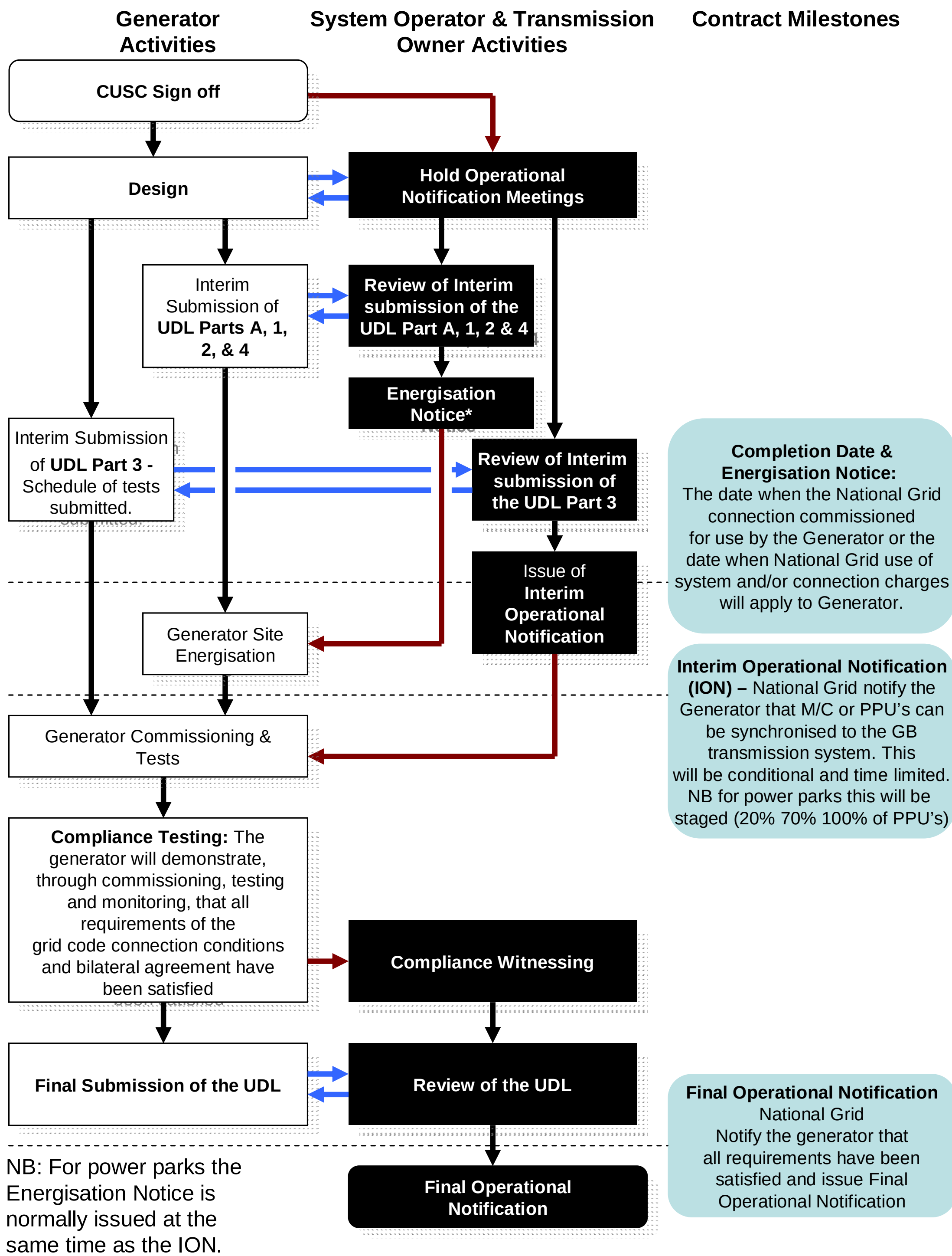
With respect to voltage fluctuations, it is also a requirement of the Grid Code that voltage fluctuations are kept within the levels given in Grid Code CC.6.1.7 and/or Table 1 of Engineering Recommendation P28 and therefore limits on voltage fluctuations are also specified in the relevant Bilateral Agreement. The Power Park Developer will be required to comply with the harmonic and voltage fluctuation limits specified in the Bilateral Agreement. The Transmission System or Distribution Network Operator will monitor compliance with these limits.

Development schemes with non-linear element(s) are assessed by the Transmission Owner for their expected impact on the harmonic distortion and voltage fluctuation levels. For harmonic voltage distortion, the process detailed in Stage 3 of Engineering Recommendation G5/4 is applied. For the voltage fluctuation, the principles outlined in Engineering Recommendation P28 are used, with contribution from the Power Park being calculated according to IEC61400-21.

Specific information required for the assessment of harmonic voltage distortion and voltage fluctuation is detailed in Grid Code DRC.6.1.1. Any component design parameters for planned reactive compensation for the Power Park as detailed in Grid Code PC.A.6.4.2 should also be included giving due attention to tuned components.

For Power Parks that are to be connected to Distribution Systems, Distribution Network Operators may undertake similar assessments to comply with the requirements of the Distribution Code in terms of harmonic distortion and voltage fluctuation.

APPENDIX H COMPLIANCE PROCESS



* Not applicable to embedded Generators

APPENDIX I USER DATA LIBRARY (UDL)

I.1 Outline Structure

The outline structure of the UDL is given below. It is important Users submit data correctly under the main five subsections as this will ensure it is routed correctly to the relevant department within National Grid and to the relevant TO / DNO

	User Data Library - Outline Structure	Lead Role	Indicative Data Sharing SO	TO
	Part A: Commercial & Legal			
A.1	Signed Legal Agreements	SO	#	
A.2	Commissioning & Test Programmes	SO	#	#
	Connection Site Commissioning & Test Programme	SO	#	#
	Generating Unit Commissioning Program	SO	#	#
	Generator Control Test Procedures and Programme	SO	#	#
A.3	Statements of Readiness	SO	#	#
A.4	TOGA Registration Details	SO	#	
A.5	Mandatory Services Agreement	SO	#	
A.6	Codes for Balancing Market Units	SO	#	
A.7	BMU Registration	SO	#	
A.8	Balancing Mechanism Process	SO	#	
A.9	Ancillary Services Monitoring	SO	#	
A.10	User Self Certification of Compliance	SO	#	
A.11	Compliance Statement	SO	#	
	Part 1: Safety & System Operation			
1.1	Interface Agreements	TO	#	#
1.2	Safety Rules	TO	#	#
1.3	Local Switching Procedures	TO	#	#
1.4	Earthing	TO	#	#
1.5	Site Responsibility Schedules	TO	#	#
1.6	Operational and Gas Zone Diagrams	TO	#	#
1.7	Site Common Drawings	TO	#	#
1.8	Control Telephony	TO	#	#
1.9	Local Safety Procedures	TO		#
1.10	Safety Co-ordinators	TO		#
1.11	RISSP	TO	#	#
1.12	Telephone Numbers for Joint System Incidents	SO	#	#
1.13	Contact Details (fax, tel, email)	SO	#	#
1.14	Local Joint Restoration Plan (incl. black start if applicable)	SO/TO	#	#
1.15	Maintenance Standards	SO/TO	#	#
	Part 2: Connection Technical Data			
2.1	DRC Schedule 5 - Users System Data	TO	#	#
2.1.1	*System Configuration Data*	TO	#	#
	Users System Layout & Single Line Diagram	TO	#	#
	Reactive Compensation	TO	#	#
	Substation Infrastructure	TO	#	#
	Circuit Parameters	TO	#	#
	Transformer Data	TO	#	#
	Switchgear Data	TO	#	#
2.1.2	*Protection Systems*	TO	#	#

	User System protection and settings	TO	#	#
	User System Auto Reclose facilities & settings	TO	#	#
	User System protection and settings	TO	#	#
	Circuit Breaker Fail	TO	#	#
	Generator Transformer protection and settings	TO	#	#
	System Fault Clearance Times	TO	#	#
	Generator protection and settings	SO	#	#
2.1.3	*User System Studies (if required)*	TO	#	#
2.2	Protection Settings Reports	TO	#	#
2.2.1	*Protection Discrimination Review*	TO	#	#
2.2.2	*Protection of Interconnecting Connections*	TO	#	#
2.3	Special Automatic Facilities e.g. intertrip)	TO	#	#
2.4	Operational Metering	TO	#	#
2.5	Tariff Metering	Elexon	#	#
2.6	Operational Communications	SO	#	#
2.6.1	*EDL & EDT*	TO	#	#
2.7	Performance Monitoring	SO	#	#
2.7.1	*Ancillary Services Monitoring*	TO	#	#
2.7.2	*Fault Recorder*	TO	#	#
2.7.3	*Dynamic System Monitor (if required)*	TO	#	#
2.7.4	*Power Quality Monitor (if required)*	TO	#	#
2.8	Power Quality Test Results (if required)	TO	#	#

Part 3: Generator Technical Data

3.1	DRC Schedule 1 - Generating Unit Technical Data	SO	#	#
3.1.1	*Table of Generator Parameters*	SO	#	#
3.1.2	*Controls System Details*	SO	#	#
3.1.3	*Generator / Station Model*	SO	#	#
3.1.4	*Power Quality - Harmonic Assessment Information*	SO	#	#
3.2	DRC Schedule 2 - Generation Planning Data	SO	#	#
3.3	DRC Schedule 4 – Frequency Droop & Response	SO	#	#
3.4	DRC Schedule 14 – Fault Infeed Data - Generators	SO	#	#
3.5	Special Generator Protection	SO	#	#
	Pole Slipping Protection (NA to Asynchronous Generation)	SO	#	#
	Islanding Protection Schemes	SO	#	#
3.6	Compliance Tests & Evidence	SO	#	#
3.6.1	*Reactive Capability*	SO	#	#
3.6.2	*Voltage Control (e.g. Excitation, AVR PSS)*	SO	#	#
3.6.3	*Frequency Response (Governor)*	SO	#	
3.6.4	*Fault Ride Through*	SO	#	
3.7	Compliance Simulation Studies	SO	#	#
3.7.1	*Model Verification*	SO	#	#
3.7.2	*Reactive Capability & Voltage Range*	SO	#	#
3.7.3	*Voltage Control & Stability (e.g. AVR, PSS)*	SO	#	#
3.7.4	*Fault Ride Through*	SO	#	#
3.8	Site Specific Technical Data & Compliance	SO	#	#
3.8.1	*Special Automatic Features e.g. intertrip*	SO	#	#

Part 4: General DRC Schedules

4.1	DRC Schedule 3 – Large Power Station Outage Information	SO	#	
4.2	DRC Schedule 6 – Users Outage Information	SO	#	
4.3	DRC Schedule 7 – Load Characteristics	SO	#	
4.4	DRC Schedule 8 – BM Unit Data (if applicable)	SO	#	
4.5	DRC Schedule 10 – Demand Profiles	SO	#	
4.6	DRC Schedule 11 – Connection Point Data	SO	#	

I.2 Final User Data Library

Updated the contents of the Interim submission to reflect any changes and add the compliance test results.

- Plant & Apparatus Type Test Results
- Reactive Capability and Voltage Control Test Results
- Frequency Response Test Results
- Fault Ride Through Power Recovery Tests (unless level 1 type validated)
- Power Quality Test Results (if applicable)

The above structure is indicative, but is a useful convention for Generators to follow. National Grid will inform the Generator where additional supporting information is required.

I.3 Protection Requirements

Under section C.C.6.2.2.2 of the Grid Code the Generator must meet a set of minimum protection requirements. As part of the Connection Conditions Compliance Report the Generator should submit a Generator Protection Settings report together with an overall trip logic diagram.

The Generator should provide details of all the protection devices fitted to the Power Park Module and Power Park Units together with settings and time delays, including:

Protection Fitted	Typical Information Required
Under / Over Frequency Protection	Number of stages, trip characteristics, settings and time delays
Under / Over Voltage protection	Number of stages, trip characteristics, settings and time delays
Over Current Protection	Element types, characteristics, settings and time delays
Reverse Power Protection	Number of stages, trip characteristics, settings and time delays
Control Trip Functions	Functional Description, Control Characteristic and trip settings
Islanding Protection (if fitted)*	Type, description, settings and time delays

*An intertripping scheme is recommended.

If anti-islanding protection is required, an inter-tripping scheme is recommended. However, if 'Rate of Change of Frequency' (ROCOF) or 'Vector Shift' trip relays are to be considered, there could be compliance implications which need to be discussed with National Grid at the earliest opportunity. National Grid does not require or desire Generators to fit ROCOF or 'Vector Shift' protection but needs to be consulted on the settings of any such protections in service.

APPENDIX J PRO FORMA AVAILABLE FROM NATIONAL GRID

This appendix includes examples of:

- 2 Compliance Statement Pro Forma's
- Power Park details required to produce the compliance statement Pro Forma
- The technical information relating to the connection bus bar that is provided by National Grid
- The summary front sheet to be completed by the Generator
- Operational Notification and Compliance Checklist

J.1 Sample Compliance Statements

The compliance statement pro forma available from National Grid is an automated document that selects relevant clauses based on Power Park details (see section 2.5). The example included in this Appendix is for a Power Park Module in Scotland embedded into the Distribution Network at 33kV with a Registered Capacity of 100MW and a completion date of the 01/10/2008.

Compliance Statement

GNPP_Scot Generator embedded in SHETL transmission area

Completion Date on 01/10/2008

Connection Voltage = 33kV, Registered Capacity = 100MW, Options: NNN3

Generation Type : Non-Synchronous Plant

Key to Evidence Requested

‘DS’	Indicates that NGC would expect to see the results of a Dynamic Simulation study.
‘G’	Manufacturer's generic data or test results, as appropriate.
‘D’	Copies of correspondence or other documents confirming that a requirement has been met (e.g. copy of letter from NGC confirming receipt of Safety Rules)
‘O’	Indicates that NGC would expect to be provided with the currently applied operating settings.
‘S’	Indicates that NGC would expect to see the results of a Simulation study (not necessarily, but not excluding, dynamic simulation).
‘P’	Generating Unit design data.
'T'	Indicates that NGC would expect to see results of, and/or witness, tests or monitoring which demonstrates compliance. Where possible, the test is referenced to the relevant section of this guidance document.
‘TV’	Indicates type validation test (if Generator pursues this compliance option)

Key to Compliance: Y = Yes (Compliant), N = No (Non Compliant) or Q = Query

REQUIREMENT					RESPONSE	
Connection Condition	Compliance Requirement of User	Evidence Requested	Lead Role	UDL Ref	Compliance Y, N or Q	User's Statement
CC.5.2	Please confirm that the following information has been submitted to NGC:					
	(a) Updated Planning Code Data, with any estimated values replaced by validated plant data;	P, G, D	SO	2.1 3.1-3.4 4		
	(b) Details of Protection (see CC.6.2);	P	TO	2.1.2		
	(d) Information to enable NGC to prepare Site Responsibility Schedules	D	TO	1.5		
	(f) The proposed Name of the User Site;	D	SO/TO	1.13		

	(i) A list of telephone numbers for Joint System Incidents; (j) List of managers authorised to sign Site Responsibility Schedules; (l) A list of telephone numbers of Fax machines (see CC.6.5.9);	D D D	SO TO SO	1.12 1.5 1.13		
CC6.1.5	Voltage Waveform Quality Refer to Distribution Network Owner (Not directly connected to GB Transmission System)					
CC.6.1.7	Voltage Fluctuations: Refer to Distribution Network Owner (Not directly connected to GB Transmission System)					
CC.6.2.1.1	Earth Fault Factor: Refer to Distribution Network Owner (Not directly connected to GB Transmission					

	System)					
CC.6.2.1.2	Substation Plant and Apparatus: Refer to Distribution Network Owner (Not directly connected to GB Transmission System)					
CC.6.2.2.2.2	Fault Clearance Times: Refer to Distribution Network Owner (Not directly connected to GB Transmission System)					
CC.6.2.2.3.1	Protection of Interconnecting Connectors:					

	Refer to Distribution Network Owner (Not directly connected to GB Transmission System)					
CC.6.2.2.3.2	Circuit-breaker Fail Protection Refer to Distribution Network Owner (Not directly connected to GB Transmission System)					
CC.6.2.2.3.3	Loss of Excitation Not Required			2.1.2		
CC.6.2.2.3.4	Pole-Slipping Protection Not Required			3.5		
CC.6.2.2.3.5	Signals for Tariff Metering: Confirm the provision of current and voltage transformers providing signals for tariff metering	D	SO	2.5		
CC.6.2.2.4	Work on Protection Equipment Confirm that appropriate working procedures have been set up and agreed with National Grid.	D	SO	2.1.2		

CC.6.2.2.5	Relay Settings: Refer to Distribution Network Owner (Not directly connected to GB Transmission System)					
CC.6.3.2	Reactive Power: Measuring active and reactive power at the User System Entry Point, carry out Test 1 to establish the maximum leading and lagging reactive capabilities. Hence confirm that sustained operation is possible in the following conditions: (1.1) Rated MW at 0.95 lag power factor (1.2) Rated MW at 0.95 lead power factor (1.3) 50% Rated MW at 0.84 lead power factor (1.4) 20% MW at 0.85 lead power factor (1.5) 20% MW at 0.52 lag power factor (1.6) <20% and 1.0 power factor (Required for PF mode only) (1.7) 20% or 50% for 30 minutes Confirm whether the NGET has been informed whether the Power Park will operator in voltage control mode or PF control below 20% Demonstrate that the tolerance on despatch of reactive power is no more than +/- 5% (numerically) of rated MW	T 1.1 T 1.2 T 1.3 T 1.4 T 1.5 T 1.6 T 1.7 P T 1, S	SO	3.6.1		

	Demonstrate that the tolerance on despatch of reactive power is no more than +/- 5% (numerically) of Rated MW at any active or reactive power output level. Please state the despatch tolerance achieved.	T 1, S				
	Describe any restrictions on MW or Mvar output resulting from connection limitations you have chosen to accept.	D				
	Provide a performance chart as specified in PC.A.3.2.2 (f) (ii) updated if necessary in accordance with the results of the above tests and showing the maximum leading and lagging reactive capabilities. If you have chosen to accept connection limitations, please show the effects (if any) of these on the chart and also show the performance the power park would achieve without them. If the limitations are not permanent, please add a note to the chart indicating the conditions under which they apply (e.g. maintenance of circuit X - Y).	P, G				
CC.6.3.3	Power Output/Frequency Characteristic:					
	Confirm that Active Power output is independent of system frequency for frequency changes within the range 49.5 to 50.5 Hz. Include characteristics which demonstrate the capability of the plant over a range of constant wind speeds	P, G	SO	3.1.2		
	Confirm that any reduction of power output due to frequency reductions at frequencies between 49.5 and 47 Hz is less than that specified in Figure 2 of CC.6.3.3 of the Grid Code. Include test data to demonstrate the characteristic	P, G				

CC.6.3.4	Voltage Range: For Embedded Power Park Modules connected at 33kV or below:					
	Carry out Simulation Study 1 to demonstrate that the Power Park Module can operate under the following conditions at Rated MW output:		SO	3.7.2		
	(1.1) unity pf at 105% nominal voltage (1.2) unit pf at 95% nominal voltage In each case the voltage, Rated MW and power factor are as measured at the User System Entry Point	P, G, S 1.1 P, G, S 1.2				
	Provide a diagram showing the variation of maximum leading and lagging reactive capabilities with voltage at the User System Entry Point, in the format of Fig 4 of CC.6.3.4. Mark the points obtainied in the tests above, on the diagram.	P, G, S 1	SO	3.1.2		
	Confirm that the maximum reactive export at voltages between 105% and 100%, and the maximum reactive import at voltages between 100% and 95%, are not less than those which would result from linear relationships between reactive current and voltage. (Fig 4 of CC. 6.3.4 refers).	P, G, S 1				
	If you have chosen to accept connection limitations, show the effect of these on the diagram and also show the performance the power park would achieve without them. If the limitations are not permanent, please add a note to the diagram indicating the conditions under which they apply (e.g. maintenance of circuit X - Y).					

CC.6.3.5	Black Start: See Bilateral Agreement to see if Black Start capability is required If applicable , provide a detailed technical statement of how the facility will be provideed. Testing of Black Start facilities will be co-ordinated by National Grid System Requirements Confirm whether or not independent power supplies are provided for jacking and barring gear						
CC.6.3.6	Control Arrangements (general):						
(a)	Frequency Control: Confirm that the requirement for frequency control can be met by 1/1/06	G	SO	3.1.2			
(b)	Voltage Control: Confirm that the requirement for reactive power control can be met	G, P	SO	3.1.2			
CC.6.3.7	Frequency Control:						
(a)	Confirm that the Power Park Module is fitted with a fast-acting proportional frequency control device and unit load controller or equivalent control device to provide frequency response under normal operating conditions	P, G	SO	3.1.2			

	State the European Specification, or other standard, to which the frequency control device is manufactured.	P, G				
BC.3.7.2	Carry out Test 3.1: with the Power Park Module operating in Limited Frequency Sensitive Mode, inject a signal equivalent to a frequency ramp changing by 0.8 Hz in 30 secs. Hold the frequency reference at the resulting value for 4 minutes.		SO	3.6.3		
	Confirm that:					
	(i) Active power output remains constant up to 50.4Hz	T 3.1				
	(ii) Above 50.4 Hz, active power is reduced, by at least 2% for each 0.1 Hz difference between the frequency signal and 50.4 Hz.	T 3.1				
	(iii) this total power change is achieved within 3.5 minutes of the start of the ramp.	T 3.1				
	Provide results of the tests as detailed in the description of Test 3.1 in the Guidance Notes	T 3.1				
(b)	Carry out Test 3.2: Operate the Power Park Module in Frequency Sensitive Mode at an active power output midway between Designed Minimum Operating Level and Register Capacity). Inject a series of step changes of frequency reference, with steps equivalent to -0.2 Hz, + 0.2 Hz, -0.5 Hz, +0.5 Hz.	T 3.2				
	Confirm that the frequency control device operates with stability for each frequency change.	T 3.2				
	Provide results of the tests as detailed in the description of Test 3.2 in the Guidance Notes	T 3.2				

(c)	Carry out Test 3.4: Operate the Power Park Module in Frequency Sensitive Mode Inject a series of rapid ramp changes of frequency reference, at different module active power outputs, as detailed in the Guidance Document.					
	Confirm that the frequency control device operates with stability for each frequency change.	T 3.4				
	Provide results of the tests as detailed in the description of Test 3.4 in the Guidance Notes	T 3.4				
	Hence confirm and demonstrate that the plant will control the frequency at or below 52 Hz under islanded conditions. Also confirm and demonstrate that the plant will not trip unless the high frequency response as established in tests 3.1and 3.2 would result in operation at less than DMOL.	P, G, T3				
(d)	Confirm the existence of a Target Frequency setting facility. State whether it is (a) continuous or (b) stepped.	P, G	SO	3.1.2		
	Please provide details of the setting range and confirm that it covers at least 50 +/- 0.1 Hz.	P, G				
	If control is stepwise, please state the step size and confirm that it is no more than 0.05Hz.	P, G, O				
Bilateral	Confirm the existence, or otherwise, of an inertial response control (df/dt) facility in the power park module control scheme.	P, G				
Bilateral	If there is an inertial response control, please confirm that it is set up in accordance with the Bilateral Agreement with NGC, and provide details of the control and its settings.	O				

	The following performance requirements must also be met from 1/01/06 onwards:					
App. 3 CC.A.3.2	Confirm the Minimum Generation of the Power Park Module, and confirm that it is not more than 65% of the Registered Capacity	P, G				
	Confirm the Designed Minimum Operating Level of the Power Park Module and confirm that it is not more than 55% of the Registered Capacity.	P, G				
CC.A.3.3 CC.A.3.4	Carry out Test 3.3: Operate the Power Park Module in Frequency Sensitive Mode at a series of different operating levels between Designed Minimum Operating Level and Registered Capacity.		SO	3.6.3		
	At each operating level, inject a series of signals into the frequency control device to simulate changes in system frequency. Measure the active power response from the Power Park Module. The operating levels (active power) and frequency changes for which tests are required are detailed in the description of Test 3.3 in the Guidance Notes					
	Confirm that: (i) Active Power Responses to 0.5 Hz frequency changes at each operating level ares not less than the minimum requirement set out in CC.A.3.3 and Fig CC.A.3.1	T 3.3				
	(ii) Active Power response to frequency changes less than 0.5 Hz are in linear proprtion to the response for 0.5 Hz. E.g. the response for a 0.2 Hz change should be 40% of that for 0.5 Hz.	T 3.3				
	(iii) Active Power response to frequency changes greater than 0.5 Hz are at least equivalent to the 0.5 Hz change					

	Provide results of the tests as detailed in the description of Test 3.3 in the Guidance Notes	T 3.3				
CC.A.3.5	From the results of Test 3.3, confirm that the full response capability of the Power Park Module can be restored within 20 minutes following a frequency disturbance.	P, G, S T 3.3				
CC.6.3.8	Voltage Control:					
(a)	Not applicable					
(b)	Confirm the existence, or otherwise, of a Power System Stabiliser facility in the Power Park Module control system.	P, G	SO	3.1.2		
	If a PSS facility exists, please confirm that it is disabled or otherwise that it is set up and commissioned in accordance with the Guidance Notes Appendix B.3.1 or as specified in the bilateral agreement	O, DS, T-B.3.1				
(c)	Confirm that the Power Park Module is fitted with a continuously-acting automatic voltage control system as required by CC.A.7.2.2.1, that controls the Voltage at the Grid Entry Point (or User System Entry Point if Embedded)	P, G	SO	3.6.2		
	Confirm and demonstrate through Study 2.3 in the Guidance Notes, that the voltage control system is stable and damped for voltage step-changes that would drive the controller against reactive limits	P, G, DS 2.3				

	Carry out the test described in Appendix A.2, as described in the Guidance Document, to show that the voltage control system provides a smooth transition between the two operating modes which apply above and below 20% of Rated MW output (if voltage control is not being offered below 20% of rated MW output).		SO	3.7.3		
	Confirm and demonstrate that the voltage control system provides a smooth reduction of reactive power to zero (subject to the tolerance set out in CC.6.3.2) as active power falls from > 20% Rated MW towards zero (if voltage control is not being offered below 20% of rated MW output).	P, G, T-A.2				
	Carry out Test B.2.4 (CC.A.7.2.5.1) imposing step changes on the voltage control system, by tap-changing and/or by injecting signals into the voltage control loop		SO	3.6.2		
	Provide test results as detailed in the description of Test B.2.4 in the Guidance Document	T-B.2.4				
	Confirm that the voltage control target voltage can be set anywhere within the range 95% to 105% of nominal voltage at the controlled busbar, with a setting resolution of no more than 0.25% (CC.A.7.2.2.2). State the target voltage setting range and resolution available. (For the avoidance of doubt, “target voltage” is the voltage at the controlled busbar at which the reactive output of the Power Park Module would be zero. It is not the same as a voltage which it is desired to achieve by the import or export of reactive power).	P, G	SO	3.1.2		

	Confirm that the slope setting of the voltage controller is adjustable within a range of 2 to 7% at a resolution of 0.5% as specified in CC.A.7.2.2.3 of the Grid Code. State the slope settings and resolution available.	P, G				
	Confirm that the slope setting currently applied is as specified in the Bilateral Agreement or 4% if the Bilateral Agreement does not specify settings. State the value of the setting.	O				
	Confirm that the reactive power change due to voltage change is as predicted by the slope setting, at any slope setting or reactive power level by performing the test in Appendix B.2.5 of the Guidance Notes.	T-B.2.5				
	Confirm that the Power Park Module will import maximum reactive current if the voltage at the voltage-controlled busbar exceeds 105% of nominal, using the results of Study 1.1 of the Guidance Notes.	P, G, S 1.1	SO	3.1.2		
	Confirm that the Power Park Module will export maximum reactive current if the voltage at the voltage-controlled busbar falls below 95% of nominal Study 1.2 of the Guidance Notes.	P, G, S 1.2				
(d)	Confirm that the Power Park Module voltage control system meets the transient performance requirements set out in CC.A.7.2.3.1 and CC.A.7.2.2.5.	P, G, T-B.2.2, T-B.2.4				
	Confirm and demonstrate that, for a step-change of reference voltage of any magnitude:					

	(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 (CC.A.7.2.3.1).	T-B.2.2, P, G				
	(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.	T-B.2.2, DS 2.1 & 2.2, P, G				
	(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.	T-B.2.2, DS 2.1 & 2.2, P, G				
	(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.	T-B.2.2, DS 2.1 & 2.2, P, G				
	(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.	DS, P, G, T-B.2.4				
	Confirm that these requirements can be met at any active power level above 20% of Rated MW (or DMOL, whichever is the greater) and across the range of system short circuit levels set out in the bilateral agreement.					
	Confirm that the bandwidth of the voltage control system is within the limits, specified in CC.A.7.2.5.2 (0-5Hz)	P, G				

(e)	Confirm the existence, or otherwise, of constant reactive power control or constant power factor control facilities in the Power Park Module voltage control system. If such facilities exist, and the Bilateral Agreement requires their use, please state the settings required by the Bilateral and the settings applied. Otherwise confirm that they are disabled.	P, G O				
CC.6.3.9	Steady State Load Inaccuracies State the standard deviation of Load error for the Generating Unit over a 30 minute period, assuming constant mechanical power input. Confirm that this standard deviation is no more than 2.5% of the Generating Unit's Registered Capacity. Test 1.7 can be used to confirm this.	T5.7	SO	3.1.2		
CC.6.3.10	Negative Phase System Loadings: If the Generator uses a directly connected synchronous generator then confirm it can withstand, without tripping, the negative sequence loading incurred by clearance of a close up phase to phase fault, by system backup protection on the GB Transmission System or User System if Embeddded.		N/A			
CC.6.3.11	Neutral Earthing:					

	Embedded Generators at < 132kV Not applicable: Earthing requirements are specified by Distribution Network Owner					
CC.6.3.12	Frequency-Sensitive Relays:					
	State the operating frequency ranges for the Generating Unit, its constituent elements and other components.	P, G	SO/TO	2.1.2		
	Confirm that all plant within the Generating Unit can operate safely over the frequency ranges and durations specified in CC.6.1.3	P, G				
	Confirm the existence, or otherwise, of any frequency-level and/or rate-of-change-of-frequency relays.	P, G				
	Either Confirm that any such frequency-sensitive relays are set to operate outside the frequency ranges specified in CC.6.1.3.	P, G				
	Please state the settings	O				
	Or Confirm that any such frequency-sensitive relays are set in accordance with the Bilateral Agreement.	P, G				
	Please state the settings.	O				

CC.6.3.13	Frequency Excursions outside 47 – 52 Hz: Confirm acceptance of responsibility for protecting the Generating Unit, its constituent elements and other components in the event of a frequency excursion outside the range 47 – 52 Hz	D	SO	2.1.2		
CC.6.3.14	Fast-Start: Not applicable					
CC.6.3.15 (a)	Fault ride-through: For a solid 3-phase, phase to phase, 2-phase to earth or 1-phase earth fault on GB transmission system operating at supergrid voltage		SO	3.6.4 3.7.4		
	Power Park Units: Provide a body of technical evidence to confirm the ability of the Power Park Unit to ride through faults of 140 ms duration	G				
	From the evidence, state the minimum retained terminal voltage(s) for which the unit will ride through a 140 ms voltage depression on one, two, or all three phases.	G				

	Demonstrate the recovery of active and reactive power following such a voltage dip. Assume that, after the voltage depression, the terminal voltage recovers to at least 90% of nominal.	G				
	Power Park: Using validated plant models as submitted under PC.A.5.4.2, carry out Simulation Study 3.1 as described in the Guidance Document. In this instance, simulate a 3-phase solid fault of duration 140 ms at the supergrid busbar and calculate voltages and current flows within the power park. The supergrid busbar, system fault infeed at that busbar and equivalent network impedance between the busbar and power park User System Entry Point are as advised by NGC [Technical lnformation Sheet supplied].					
	Calculate for a range of power output levels, reactive exports/imports and grid supply point voltages.					
	Power Park components: Demonstrate that the individual units can withstand 140 ms voltage dips at lower retained voltages than the unit terminal voltages calculated in Simulation Study 3.1. Hence confirm that the Power Park will ride through a 140 ms 3-phase supergrid fault.	G, DS3.1				
	Power Park: Calculate voltages and current flows within the power park during the period after fault clearance and until 10 seconds after supergrid voltage restores to the minimum values of CC6.1.4 as advised by NGC in the Information Sheet.	DS 3.1				

	Power Park units: Using the results of the Simulation Study 3.1 and manufacturer's design and test data for individual units, confirm that total active power outputs will be restored to 90% of pre-fault level within 0.5 seconds after fault clearance.	G, DS3.1				
	Power Park Units: Confirm that currents calculated in the simulation of the fault and recovery lie within the transient rating limits of the power park units and other components.	G, DS3.1				
	Confirm that no reactive current limiters will operate during the fault or after fault recovery	G				
CC.6.3.15 (b)	Fault ride-through:					
	Power Park Units: Provide a body of technical evidence to confirm the ability of the Power Park Unit to ride through balanced voltage dips.		SO	3.6.4 3.7.4		
	From the evidence, state the minimum retained terminal voltage for which the unit will ride through voltage depressions lasting: 384ms, 710ms, 955ms, 2.5sec, 3 min	G				

	Provide evidence (or estimates) of how the terminal voltage, active and reactive power would vary with time through the voltage depression and recovery, for at least 10 seconds after the end of the voltage depression. Assume that the terminal voltage recovers to 90% of nominal value after the depression.	G				
	Power Park: Using validated plant models as submitted under PC.A.5.4.2, carry out Simulation Study 3.2 as described in the Guidance Document. In this instance, simulate a series of balanced 3-phase voltage dips at the Supergrid busbar and calculate voltages and current flows within the power park. The Supergrid busbar, system fault infeed at that busbar and equivalent network impedance between the busbar and power park User System Entry Point are as advised by NGC and used in the CC6.3.15(a) compliance assessment, above. [Information Sheet supplied].					
	The voltage dips and durations studied are to be consistent with Fig. 5 of CC. 6.3.5 (b) and should include:					
	30% voltage for 384ms	DS 3.2				
	50% voltage for 710 ms	DS 3.2				
	65% voltage for 955 ms	DS 3.2				
	80% voltage for 2.5 sec	DS 3.2				
	85% voltage for 180sec	DS 3.2				
	Calculate for a range of power output levels, reactive exports/imports and grid supply point voltages					

	Power Park units: Confirm and demonstrate that the unit terminal voltages calculated in Simulation Study 3.2 are in all cases greater than the minimum ride-through voltages indicated in the evidence presented. Hence confirm that the Power Park will ride through a balanced 3-phase voltage dips as specified in CC.6.3.15 (b) without tripping or instability From the study results and technical evidence, confirm and demonstrate that the total active power during the voltage dip will always be at least in proportion to the retained voltage at the User System Entry Point Similarly, confirm and demonstrate that total active power outputs will be restored to 90% of pre-dip level within 1 second of voltage at the User System Entry Point restoring to 90% of nominal or greater. Confirm that currents calculated in the simulation of the voltage dip and recovery lie within the transient rating limits of the power park units and other components.	G, DS 3.2 G, DS 3.2 G, DS 3.2 G				
CC.6.3.15 (c) **ii)**	Negative Phase Sequence loading during faults cleared by back-up protection: Power Park Units: Provide a body of technical evidence to show the maximum phase (voltage) unbalance that the unit can withstand for the fault duration specified in the Information Sheet.		SO	3.6.4 3.7.4		

	Power Park: Using validated plant models as submitted under PC.A.5.4.2, simulate a solid phase-to-phase fault at the supergrid busbar cleared by System back-up protection and calculate the positive phase- and negative-phase sequence voltages and currents within the power park and the phase (voltage) unbalance imposed on the power park units The supergrid busbar, system fault infeed at that busbar, fault duration and equivalent network impedance between the busbar and power park User System Entry Point are as advised by NGC [Information Sheet supplied]. Calculate for a range of power output levels, reactive exports/imports and grid supply point voltages	S3.3				
	Power Park Units: Confirm that power park units and other components will withstand the phase (voltage) unbalance calculated above for the fault duration specified in the Information sheet without tripping	G				
iv)	Tripping under islanded conditions: Confirm that there is equipment to detect frequency [or say frequency-sensitive relay?] above 52 Hz and automatically trip the power park module if the condition persists for longer than 2 seconds	P, G	TO	2.1.2		

	Similarly, confirm that there is equipment to detect frequency below 47 Hz and automatically trip the power park module if the condition persists for 2 seconds or longer	P, G				
	Confirm that there is equipment to monitor voltage at User System Entry Point (or User System Entry Point, as appropriate) and automatically trip the power park module if voltage falls below 80% of nominal for more than 2 seconds.	P				
	Similarly, confirm that there is equipment to monitor voltage at Grid Entry Point (or User System Entry Point, as appropriate) and automatically trip the power park module if voltage rises above 120% of nominal for more than 1 second.	P				
	Negative Phase Sequence loading during faults cleared by back-up protection:					
CC.6.5.4	Control Telephony: Confirm that control telephony is provided and installed in accordance with the Bilateral Agreement	D	SO/TO	1.8		
CC.6.5.6	Operational Metering Confirm that Operational Metering is provided and installed in accordance with the Bilateral Agreement	D	TO	2.4		
CC.6.5.7	Instructor Facilities:					

	Confirm that accommodation is provided for NGC Instructor Facilities	D	SO	1.8		
CC.6.5.8	Electronic Data Communication (EDT) Facilities: If the User is a BM Participant					
(a)	Confirm that electronic data transmission facilities have been provided and installed.	D	SO	2.6		
(b)	Confirm that electronic data logging facilities are installed at the control Point of the Power Park Module.	D				
CC.6.5.9	Facsimile Machines:					
(a)	Confirm the provision of facsimile machines at the Control Point, and at the Trading Point, of the Power Park Module	P	SO	1.13		
CC.6.6.1	System Monitoring: If a requirement for System Monitoring has been agreed with NGC:		SO	2.7		
	Confirm the provision of signals from the Generating Unit for system monitoring, and space for system monitoring equipment.	P				
CC.7.2.6	Safety Rules I: Not Applicable					

CC.7.2.7	Safety Rules II: Not Applicable					
CC.7.3.1, CC.7.3.2	Site Responsibility Schedule: Not Applicable		TO	1.5		
CC.7.4.1 – CC.7.4.3, CC.7.4.7, CC7.4.8	Operation Diagram: Not Applicable					
CC.7.4.4 – CC.7.4.6, CC.7.4.9	Gas Zone Diagram: Not Applicable					

CC.7.5	Site Common Drawings: Not Applicable					
CC.7.6	Access: Not Applicable					
CC.7.7	Maintenance Standards: Not Applicable					
CC.7.9	Control Point:					
	Confirm the provision of a Control Point for the Generating Unit	D	SO	1.13		
	Confirm that the Control Point will be continuously manned.	D				
	State the location of the Control Point.	P				

CC.8.1	System Ancillary Services Confirm the capability to provide System Ancillary Services as follows: Reactive Power: Confirm that the Power Park Module meets the requirements of CC.6.3.2 and CC.6.3.4. Demonstrate the capability by means of test results (see Statement No 12, CC.6.3.2) if available or by calculation or simulation study using validated plant and system data. Frequency Response: Confirm that the Power Park Module meets the requirements of CC.6.3.7. Provide a validated frequency response capability diagram in the format of Fig. CC.A.3.1 in Appendix 3 of the Connection Conditions.		SO	A.5		
CC.8.2	Commercial Ancillary Services Confirm the availability or otherwise of Commercial Ancillary Services.		SO	A.5		
BCA - F5	Bilateral Connection Agreement Appendix F5 Confirm the availability or otherwise of Commercial Ancillary Services.		SO	A.5		

J.2 Power Station Details

The following data is required to generate a compliance statement pro forma for each Power Park.

Power Station Details

Completion Date (generally energisation date)	
Power Park Module Registered Capacity (MW)	
Type of Connection (Embedded in a Distribution Network “D” or connection directly to the GB Transmission System “T”)	
Connection Voltage (400, 275, 132, 66, 33 or 11 kV)	
Transmission Area (National Grid, Scottish Power SPT, Scottish Hydro SHETL)	

Supplementary Questions

If the Power Park Module is directly connected to the GB Transmission System is the connection made at the Generators Site. Yes/No.	
How is the Generator proposing to demonstrate Fault Ride Through Capability? Level 1, 2 or 3.	

Where Connection Condition paragraph makes reference to the Bilateral Agreement, the Generator's Compliance response should be against the Bilateral Agreement requirement.

J.3 Technical Information on the Connection Bus Bar

This information is provided to the Generator to Establish Compliance with Grid Code and other technical requirements.

Busbar on GB Transmission System operating at Supergrid Voltage:	Example 1 (Scottish Power Area 275 kV)	275kV

Item	Max	Min	Unit
Symmetrical Three-phase short circuit level at instant of fault from GB Transmission System (based on transient impedance)	19000	1300	MVA
Equivalent system reactance between the Supergrid Busbar and Power Park Module Point of Connection.	3.9	3.6	% on 100 MVA
Total clearance time for fault on GB Transmission System operating at Supergrid Voltage, cleared by System Back-up Protection (C.C.6.3.15 (c))	800		msec

Equivalent Circuit between Supergrid Busbar and Power Park Module Point of Connection (showing transformer vector groups):

[For CC6.3.15 (c) assume system 'nps' impedance pre-and post-fault such that CC6.1.6 limits met]

J.4 Compliance Statement Summary Front Sheet

This summary front sheet is required to certify that the Power Park Module is compliant with the Grid Code Connection Conditions and Technical Appendices of the Bilateral Agreement in all aspects other than any exceptions listed.

Power Station/Park Module:	[NAME]	**Generator:**	[GENERATOR]	**Registered Capacity (MW):**	[MW]
Connected to:	[NETWORK GENERATOR]	network at	[SSTN NAME]	substation	
Main Contractor:	[CONTRACTOR]		**Power Park Unit Manufacturer :**	[NAME]	

This Report records the compliance of [NAME] Power Park with the Connection Conditions of the Grid Code and the technical requirements of the Bilateral Agreement.

National Grid Company's specific requirements and guidelines for demonstrating compliance are set out in the following pages. We have recorded our compliance against each item, together with references to supporting evidence and a commentary where this is appropriate.

Supporting evidence, in the form of simulation results, test results, manufacturer's data and other documentation, is attached as Appendices.

[GENERATOR] certifies that the Power Park is compliant with the Connection Conditions and Technical Appendices of the Bilateral Agreement in all aspects, with the following exceptions and queries:

Statement No.	Connection Condition	Requirement	Ref:	Issue

Compliance certified by:	Name: [PERSON] Signature: [PERSON] Date: [DATE]	Title: [PERSON DESIGNATION] Of [GENERATOR]

J.5 Operational Notification and Compliance Checklist

The diagram below shows the start of the Operational Notification and Compliance Checklist spreadsheet, which is available from National Grid. This spreadsheet identifies the expected timescales for various actions.

NATIONAL GRID PLC

GB Reference: GB000EX1

Operational Notification and Compliance Checklist

Key Activities and Dates (Customer)

Customer:	ACME Power Company		Energisation Date:	09.07.2008
Connection Site:	Road Runner Avenue		Synchronisation Date:	09.07.2008
Date of Bilateral/Construction Agreement:		27/10/2005	Transmission Company Commissioning Date & Effective From Date (BSCP 15 terminology)	08.07.2008
Comm. Prog. Commencement Date:		18/06/2008	Completion Date:	09.07.2008

Connection Type:	GEP	DNO:	n/a	Capacity	250.0 MW
Direct or Embedded?	Direct	Affected TO:	National Grid	Connection Voltage	400 kV
TO/Host TO:	SPT	BM Unit?	Yes		

Item No.	Information/Data and Activity Requirements	Code or Agreement Ref.	User Data Library Ref.	Sources of Guidance to User:	Adopted Date	Interim Approval: Planned Date	Final Approval: Planned Date	Notes and Information for User Checklist: Generic Information; to be replace by connection specific comments before issue to the User.	SPT Contact - for TO requirement
0.00001	**Before Start of Commissioning:**								
1.03	Connection Condition Compliance Statement Pro-formas specific to this project received from National Grid				27/10/05	27/10/05		NGC will send a pro-forma for submission of statements of Compliance with Grid Code Connection Conditions and Site -specific requirements ("F Appendices"). The proforma will specify which Conditions apply to this connnection and indicate how compliance can be demonstrated	Joe Soap
1.101	Register with TOGA system for outage data submission, and test submission process		4.1 (Gen) 4.2 (User	National Grid Industry Information website http://www.nationalgrid.com/uk/Electricity/Codes/gridcode/associateddocs/ provides documentation of TOGA system.	27/10/05	27/10/05		NGC has an on-line system for the exchange of outage forecast data. Users should register on the system as soon as possible after acceptance of the Offer of a CUSC Contract.	Joe Soap
1.201	Detailed Planning Data (Committed Project Planning Data): Generating Units	PC5.4 / PC4.4.2, PC.A.5	3		24/11/05	24/11/05			
1.202	Detailed Planning Data (Committed Project Planning Data): User System Data	PC5.4 / PC4.4.2, PC.A.6	2.1		24/11/05	24/11/05			
2.1	Safety Rules applicable during commissioning agreed with SPT	OC8/CC5.2 CONSAG 2.1	1.2		27/01/06	27/01/06			Joe Soap
2.2	Safety Rules applicable after commissioning: agreed with SPT	OC8/CC5.2 CUSC 2.10	1.2						Joe Soap
3.11	Local Safety Instructions applicable during commissioning agreed with SPT	OC8/CC5.2 CONSAG 2.1	1.2		27/01/06	27/01/06			Joe Soap
3.12	Local Safety Procedures applicable during commissioning agreed with SPT	OC8/CC5.2 CONSAG 2.1	1.2		27/01/06	27/01/06			Joe Soap
	Local Safety Instructions applicable								

APPENDIX K CONTACT NAMES & ADDRESSES

There are a number of different parts of National Grid, each with key areas of expertise and responsibilities relevant to connection of a Generator. The complete process is controlled by the Commercial Contact. A Commercial Contact is assigned to each new connection and should be the first point of contact in the event that the appropriate contact has not been identified. The Commercial Contacts all report to the "Electricity Customer Manager", who is responsible for allocating the Commercial Contacts to specific connections. The contact details for the Electricity Customer Manager, is listed below:

Stuart Easterbrook – Electricity Customer Manager – Tel: 01926 65 6213
Email: stuart.easterbrook@uk.ngrid.com

The Generator Dynamic Performance Team is responsible for the majority of the technical aspects related to Generation. An engineer from this team will be assigned to each new connection by the team leader. The contact details of the team leader are listed below:

Helge Urdal – Generator Dynamic Performance Manager – Tel: 01926 65 4601
Email: helge.urdal@uk.ngrid.com

The responsibility for DRC guidance and week 24 data submission process lies with Network Strategy department. The contact details of its departmental head are listed below:

Keith Dan – Analysis Systems and Data Team Leader – Tel: 01926 65 5336
Email: keith.dan@uk.ngrid.com

As described in the earlier sections of this document, the Users submit the data to the Commercial Contacts in a standard format known as the User Data Library (UDL) which is divided into 5 major sections. These in turn, are further divided into related subsections. The following lists senior contacts within National Grid for the five major sections and where appropriate details more appropriate contacts relating to specific topics within those sections.

Part A – Commercial & Legal – Stuart Easterbrook (see above for details)

In relation to the following specific topics please refer to the associated contact:

Toga Registration–Jeremy Caplin 01189 363288 jeremy.caplin@uk.ngrid.com
Mandatory Service Agreement–David M Smith 01926 655534 dave.m.smith@uk.ngrid.com
Codes for Balancing and BMU Registration–Sue Stewart 01189 363124 email sue.stewart@uk.ngrid.com
Balancing Mechanism Process– Neil Sutton 01189 363147 neil.sutton@uk.ngrid.com
Ancillary Service Monitoring–Alex Carter 01189 363493 alex.carter@uk.ngrid.com

Part 1 – Safety & System Operation

The Transmission Owner is the main point of contact for the Safety and System Operation section. Where National Grid is the Transmission Owner, Commercial Contacts are the interface for all subsections relating to Part 1.

In relation to the following specific topics please refer to the associated contact:

Contact Details & Joint System Incidents Telephone Numbers – Neil Sutton (see above)

Part 2 – Connection Technical Data and Compliance

The Transmission Owner is the main point of contact for the Connection Technical Data and Compliance section. Where National Grid is the Transmission Owner, the Commercial Contacts are the interface for all subsections relating to Part 2.

In relation to the following specific topics please refer to the associated contact:

Tariff Metering–Elexon 020 7380 4222 helpdesk@elexon.co.uk

Operational Communications (EDL & EDT) – Chris Proudfoot (see above)
Ancillary Services Monitoring – Alex Carter (see above)

Part 3 – Generator Technical Data and Compliance – Helge Urdal (see above for details)

In relation to the following specific topics please refer to the associated contact:

DRC Schedule 2 – Jeremy Caplin (see above)
DRC Schedule 14 – Keith Dan 01926 655336 keith.dan@uk.ngrid.com
Site Specific Technical Data and Compliance – Neil Sutton (see above)

Part 4 – General DRC Schedule – Commercial Contact

In relation to the following specific topics please refer to the associated contact:

DRC Schedule 3 & 6 – Jeremy Caplin (see above)
DRC Schedule 8 – Sue Stewart (see above)

Contact Address:

National Grid, National Grid House, Warwick Technology Park, Gallows Hill, Warwick CV34 6DA

National Grid

National Grid is an international energy delivery business whose principal activities are in the regulated electricity and gas industries.

National Grid is the Great Britain System Operator and owns and develops the high-voltage electricity transmission network in England & Wales.