nationalgrid

Guidance Note

DC Converter Stations

Prepared by National Grid (Plc)

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NOTES

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Foreword

These Guidance Notes have been prepared by National Grid Electricity Transmission (NGET) to describe to Generators how the Grid Code Compliance Processes should work.

These Guidance Notes are prepared, solely, for the assistance of prospective DC Converter Station owners connecting directly to the National Electricity Transmission or (if the installation has a rating of 50MW or more) to a User's System.

In the event of dispute, the Grid Code and Bilateral Agreement documents will take precedence over these notes.

Owners of installations rated 50MW or less should contact the relevant Distribution Network Operator (DNO) for guidance.

These Guidance Notes are based on the Grid Code, Issue 5, Revision 0, effective from the 17 August 2012.

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

The Electricity Customer Manager (see contact details) will be happy to provide clarification and assistance required in relation to these notes and on Grid Code compliance issues.

National Grid welcomes comments including ideas to reduce the compliance effort while maintaining the level of confidence. Feedback should be directed to the National Grid Generator Compliance team at:

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Contents

Abbreviations

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

Abbreviation	Description
AVC	Automatic Voltage Control (on transformers)
BA / BCA	Bilateral Agreement / Bilateral Connection Agreement
BC	Balancing Code
BM / BMU	Balancing Mechanism / Balancing Mechanism Unit
CC / CC.A	Connection Conditions / Connection Conditions Appendix
CCGT	Combined Cycle Gas Turbine
CSC	Current Source Converter
CUSC	Connection and Use of System Code
DC	Direct Current
DNO	Distribution Network Operator
DMOL	Design Minimum Operating Level
DPD	Detailed Planning Data
DRC	Data Registration Code
EDL/EDT	Electronic Data Logging / Electronic Data Transfer
ELEXON	Balancing and Settlement Code Company
FON	Final Operational Notification
FRT	Fault Ride Through
FSM	Frequency Sensitive Mode
GB	Great Britain
GCRP	Grid Code Review Panel
HVDC	High Voltage Direct Current
ION	Interim Operational Notification
LSFM	Limited Frequency Sensitive Mode
LON	Limited Operational Notification
MEL	Maximum Export Limit
MLP	Machine Load Point

NGET	National Grid Electricity Transmission
OC	Operating Code
OFGEM	Office of Gas and Electricity Markets
PC	Planning Code
PSS	Power System Stabiliser
RISSP	Record of Inter System Safety Precautions
SEL	Stable Export limit
SO	System Operator (National Grid)
SPT	Scottish Power Transmission
SHETL	Scottish Hydro Electric Transmission Limited
STC	System Operator Transmission Owner Code
TO	Transmission Owner
TOGA	Transmission Outages, Generation Availability
UDFS	User Data File Structure
UEL	Under Excitation Limiter
VSC	Voltage Source Converter

Introduction

This document complements the Compliance Processes included in the Grid Code providing additional description of the technical studies and testing set out within the Grid Code.

To achieve Operational Notification the DC Converter Station owner 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 between National Grid and the Interconnector Owner, which for technical reasons, may specify additional/alternative requirements or specific parameters within a range indicated in the Grid Code. The total requirements placed on DC Converter Stations are therefore the aggregation of those specified in the Grid Code and Bilateral Agreement.

This particular edition of the guidance notes has been written for DC Converter Station owners, separate guidance documents exists for Synchronous Generating Units and Power Park Modules.

DC Converter Station owners 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.

Compliance Processes within the Grid Code

The process for DC Converter Station owners to demonstrate compliance with the Grid Code and Bilateral Agreement is included in the Grid Code Compliance Processes (CP). In addition to the process and details of the documentation that is exchanged to control the process an appendix to the Compliance Processes includes the technical details of the simulation studies that a DC Converter Station owner should carry out. The Compliance Processes cross reference heavily with the Planning Code, the Connection Conditions and Operating Code 5.

The Grid Code Planning Code (PC) sets out the data and information that a DC Converter Station owner is required to submit prior to connection and then maintain during the lifetime of the DC Converter station. The format for submission of the majority of this information is set out in the Data Registration Code (DRC).

The Grid Code Connection Conditions (CC) set out the majority of the generic performance requirements that a DC Converter Station owner is required to meet with site specific variations laid out in the Bilateral Agreement.

The Grid Code Operating Code 5 (OC5) sets out the technical details of the tests which National Grid recommends to demonstrate compliance with the Grid Code.

Model

The DC Converter Station owner is required to provide National Grid and the Transmission Owner (for sites in Scotland) with a model of their DC Converter as detailed in PC.A.5.4.3 of the Grid Code. The model data is to be provided in transfer functions block diagram format. Control systems with a number of discrete states or logic elements may be provided in flow chart format if a transfer function block diagram format does not provide a suitable representation.

The model structure and complexity must be suitable for National Grid to integrate into their power system analysis software (currently DigSilent), for power system dynamic simulation studies. In cases where the model's functionality cannot be correctly or satisfactorily represented within National Grid's power system analysis software, the DC Converter Station owner may be required to liaise with National Grid to determine appropriate simplifications or changes in representation to produce an appropriate model.

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 DC Converter Station owner'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 the model accuracy.

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 maybe required from the DC Converter owner 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).

Simulation Studies

Simulation studies and site tests are required to provide evidence that the DC Converter Station's plant and apparatus comply with the provisions of the Grid Code. Section of the Grid Code CP.A.3 describes the simulations studies which need to be carried out before any DC Converter Station will be issued an Interim Operational Notification (ION) as indicated in.CP.6.3

In general simulation studies are required where:

a) It is impractical to demonstrate capability through testing as the effects on other system users would be unacceptable.
b) It is necessary to predict the DC Converter behavior before tests are carried out.

CP.A.3 outlines simulation studies that are required to verify compliance with Grid Code requirements. The simulations must be based on the models supplied to National Grid in accordance with Grid Code Planning Code except for the load rejection simulations in CP.A.3.6 where a more complex model may be utilised if appropriate provided a validation study as specified in CP.A.3.6.6 is also provided.

Simulations should be submitted in the form of a report (CP.A.3.1.2) to demonstrate compliance in sufficient time to allow National Grid to review the content and validity of the report and models utilised prior to the planned synchronisation date (typically 3 -6 months).

Compliance Testing

Tests identified in OC5.A.4 of the Grid Code are designed to demonstrate where possible that the relevant provisions of the Grid Code and Bilateral Agreement have been met. However if the test requirements described in OC5.A.4 are at variance with the Bilateral Agreement or the test requirements are not relevant to the plant type the DC Converter Station owner should contact National Grid to discuss and agree an alternative test program and success criteria.

For each test to be carried out the description and purpose of the test to be carried out, results required, the relevant Grid Code clause(s) and criteria of assessment are given in OC5. The DC Converter Station owner is responsible for drafting test procedures for the DC Converter station as part of the compliance process prior to the issue of the ION. Grid Code OC5 and the appendices of these Guidance Notes provide outline test schedules which may assist the DC Converter Station owner with this activity.

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 submissions of User Data File Structure.

The tests are carried out by the DC Converter Station owner, or by their agent, and not by National Grid. However, National Grid will witness some of the tests as indicated in OC5. Tests should be completed following the test procedures supplied in the UDFS prior to the issue of the ION unless otherwise agreed by National Grid.

The DC Converter Station owner should also provide suitable digital monitoring equipment to record all relevant test signals needed to verify the DC Converter Station performance in parallel with National Grid's recording equipment.

National Grid Data Recording Equipment

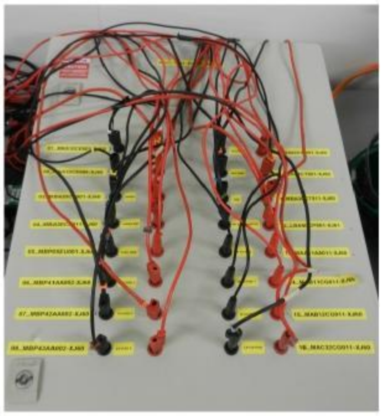
National Grid will provide a digital recording instrument on site during the tests witnessed by National Grid. A generic list of signals to be monitored during National Grid witnessed tests is tabulated in OC5.A.1.2. This will be used to monitor all plant signals at the sampling rates indicated in CC.6.6.2. The station should provide its own digital recording equipment to record the same plant variables. This will provide a back up to the test results should one of the recording instruments fail at the time of testing.

The station is responsible for providing the listed signals 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 (see CC.6.6.2). The input impedance of the National Grid equipment is in the region of 1MOhm and its loading effect on the signal sources should be negligible.

The station should advise National Grid of the signals and scaling factors prior to the test day. The form of a typical test signal schedule is shown below

Signal	Unit	Voltage Range	Signal Representation
Active Power Output	MW	0 to 8V	0 to Reg. Capacity
System Frequency	Hz	-8V to +8V	48.0Hz – 52Hz
List of other signals			

It may be appropriate for National Grid to set up the recording equipment on the day prior to the test date. The station representatives are asked to ensure that a 230V AC power supply is available and that the signals are brought to robust terminals at a single sampling point. Examples of ideal connection points with BNC or 4mm banana plug connections are shown below.



The station must inform National Grid if the signal ground (0V) is not solidly tied to earth or of any other potential problems.

Test Notification to Control Room

The station 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 National Electricity 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 in Grid Code, Associated Documents.

The station should be aware that this interface with National Grid transmission planning will normally be available in week-day working hours only. As best practice the station 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 station, then the proposed testing may not be allowed to proceed.

Model Validation

The results recorded during the compliance tests may be used to validate the DC Converter Station model as provided under the Grid Code Planning Code.

The compliance testing may have proved that the DC Converter Station and its control systems are compliant but the recorded behaviour tests may be different from the behaviour predicted by the simulation studies using the provided models. The differences may be due to the following reasons.

- The simulation conditions are different from the test conditions.
- The model supplied may be not accurate.

Following successful compliance tests the DC Converter Station owner should validate the performance of the submitted model by providing overlays of recorded tests with simulations replicating as far as reasonably practical the same conditions.

Simulation should be carried out under test conditions and the simulation results should be then compared with the test results. If the simulation results are identical or matched very well with the test results then the submitted model has been validated and accepted as the accurate model of the plant. If the results are different, then the DC Converter Station owner should resubmit a modified model. This process will be repeated until there is close agreement with the test results and simulation results.

Protection Requirements

Under section CC.6.2.2.2 of the Grid Code the DC Converter Station owner must meet a set of minimum protection requirements. As part of the User Data File Structure (UDFS) section 2 the DC Converter Station owner should submit a Protection Settings report together with an overall trip logic diagram.

The DC Converter Station owner should provide details of all the protection devices fitted to the DC Converter Station 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

Power Quality Requirements

For DC Converter Stations that are to be connected to the National Electricity 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 nonlinear 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 DC Converter Station Owner 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. Both assessments may lead to a requirement within the Bilateral Agreement specifying maximum permissible limits not to be exceeded.

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 DC Converter as detailed in Grid Code PC.A.6.4.2 should also be included giving due attention to tuned components.

For DC Converters 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 A - Reactive Capability

Summary of Grid Code Reactive Capability Requirements

The reactive capability requirements for DC Converter Stations are specified in Grid Code CC.6.3.2.

In summary the requirements of an Offshore DC Converter Station and Onshore DC Converter Station and those Converters using different technology such as Voltage Source Converters (VSC) and Current Source Converters (CSC) are different as follows:-

a. The Grid Code requirement CC.6.3.2.(b) applies to Onshore DC Converter Stations, both to those stations using Current Source Converter (CSC) technology and Voltage Source Converter (VSC) technology.
b. The Grid Code requirement CC6.3.2 (c) applies to Onshore DC Converters Stations using VSC.
c. The Grid Code requirement CC.6.3.2.(e) applies to Offshore DC Converter Stations.

CC.6.3.2 (b) requires the Onshore DC Converter to be capable of operating with zero reactive power transfer to the public power system (with a tolerance) from zero active power output to full active power output.

CC6.3.2(c) requires the DC Converter Station to be capable of operating with a range of reactive power outputs when producing more than 20% real power. This reactive power capability at the connection point (or HV side of the connection transformer for a "Transmission" connection site in Scotland) is illustrated in the diagram CC.6.3.2. fig 1. Below 20% real power output the Onshore DC converter may continue to modulate reactive power transfer under voltage control or switch to zero reactive power transfer. If there is a switch to zero reactive power transfer the Grid Code 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%.

CC6.3.2(e) requires that zero transfer or an agreed transfer capability to be specified. The agreed transfer is to be specified in the Bilateral Agreement.

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 CC.6.3.4 capability is not normally tested but is instead demonstrated by simulation. CP.A.3.3 details the requirements for a simulation study.

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.

Contractual Opportunities Relating to Reactive Services

For some technologies there is an opportunity to provide an optional reactive service (beyond the basic mandatory reactive service). Developers interested in providing such a service should take the opportunity of reactive capability testing to demonstrate any additional reactive capability. The delivery of additional reactive power would be expected to be dynamic, i.e. responding to changes to system voltage in the same manner as the mandatory reactive service provided.

Reactive Capability Compliance Tests

Grid Code OC5.A.4.2 and OC5.A.4.3 describes the Reactive Capability testing for both DC Converter Stations using Voltage Source Converter (VSC) and Current Source Converter (CSC) technologies respectively. For CSC technology plant, the tests are intended to demonstrate the maintenance of zero transfer of reactive power under varying active power and voltage conditions, the tolerance on maintenance of zero reactive power is stated in the bilateral agreement.
For the VSC technology plant, required tests should demonstrate the maximum capability of the DC Converter beyond the corners of the envelope shown in Grid Code CC.6.3.2 Figure 1. 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 Reactive Capability test is not usually witnessed by a National Grid compliance engineer.

In order to demonstrate that a DC Converter can satisfy the reactive capability requirements it is necessary to perform reactive capability tests as set out in OC5.A.4.2.5. The following should be completed for both importing and exporting of Active Power An example of a corresponding test schedule is shown below.

Test No	Step	Description	Notes
1		Plant in Voltage Control Increase Active power output to maximum export Target Voltage selected to generate a maximum continuous lagging Reactive Power for 60 minutes.	
2		Maintain Active power output to maximum export Target Voltage selected to generate a maximum continuous leading Reactive Power for 60 minutes.	
3		Reduce active power export to 50% Rated MW Target Voltage selected to generate a maximum continuous leading Reactive Power for 5 minutes.	
4		Reduce active power export t to 20% Rated MW Target Voltage selected to generate a maximum continuous leading Reactive Power for 5 minutes.	
5		Maintain active power export to 20% Rated MW Target Voltage selected to generate a maximum continuous lagging Reactive Power for 5 minutes.	
6 (Note1)		Increase Active power export to 25% Rated MW Target Voltage selected to generate a value of Lagging Reactive Power greater than 5% Rated MW Reduce Output to <20% as a ramp over 10 seconds Hold Output <20% for 5 minutes	

7 (Note2)		Reduce active power to 0 MW Target Voltage selected to generate a max Lagging Reactive Power maximum continuous lagging Reactive Power for 5 minutes.	
8 (Note2)		Maintain active power to 0 MW Target Voltage selected to generate maximum continuous leading Reactive Power for 5 minutes.	
9 (Note1)		Increase Active power import to 25% Rated MW Target Voltage selected to generate a value of Lagging Reactive Power greater than 5% Rated MW Reduce Output to <20% as a ramp over 10 seconds Hold Output <20% for 5 minutes	
10		Reduce active power import to 20% Rated MW Target Voltage selected to generate a maximum continuous lagging Reactive Power for 5 minutes.	
11		Maintain active power import to 20% Rated MW Target Voltage selected to generate a maximum continuous leading Reactive Power for 5 minutes.	
12		Increase active power import to 50% Rated MW Target Voltage selected to generate a maximum continuous leading Reactive Power for 5 minutes	
13		Increase Active power import to maximum Target Voltage selected to generate a maximum continuous leading Reactive Power for 60 minutes	
14		Plant in Voltage Control Increase Active power import to maximum Target Voltage selected to generate a maximum continuous lagging Reactive Power for 60 minutes.	

Notes

1. If the DC Converter Station does not provide voltage control below 20% active power output then test 6 should be carried out to demonstrate smooth transition to within the required reactive power envelope.
2. If the DC Converter Station provides voltage control down to zero active power output then tests 7 and 8 should be performed.

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Appendix B – Voltage Control Testing

Reactive Capability tests are not normally witnessed by National Grid so where a DC Converter Station Owner is recording the tests the following test record sheet is suggested.

RECORD OF REACTIVE POWER MONITORING RESULTS

DC CONVERTER STATION ....

Date of Test ....

DC Converter Station Control Engineer .... NGC Control Engineer

Test Data Recorded by ....for ....(Company)

DC Converter Station	Time	MW Import/Export At Connection	MVAr Lead/Lag At Connection Point	Voltage At Connection Point	Tap* Position (if known)	HV* Voltage (if known)

* Scottish Connections where Connection Transformer owned by Transmission

Owner OBSERVATIONS / REMARKS

Appendix B – Voltage Control Testing

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

Grid Code CC.6.3.8(a)(iv) States that the performance requirements will either be stated in the Bilateral Connection Agreement (pre 1 January 2009) or in CC Appendix 7.

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 DC Converter Station 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.
- Grid Code Figure CC.A.7.2.2(b) Illustrates the operational envelope required.

The DC Converter Station Owner must provide National Grid with a transfer block diagram illustrating the DC Converter 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 File Structure (UDFS). The information will enable National Grid to review the suitability of the proposed test programme to demonstrate compliance with the Grid Code.

Setpoint Voltage and Slope

The National Grid Control Centre issues voltage control instructions to all Balancing Market participants. For DC Converter Stations the usual instruction is to alter Setpoint Voltage and should be carried out in the usual 2 minutes required for Ancillary Service instructions. The slope may also be varied by control instruction but the DC Converter Station Owner has up to a week to complete the change. Slope is usually expected to be set at 4%. The procedures for Voltage Control instructions are included in Grid Code Balancing Code (BC) 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. 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 DC Converter 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.

Transient Response

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

Figure B.1 illustrates a control scheme which employs a constant speed of response.

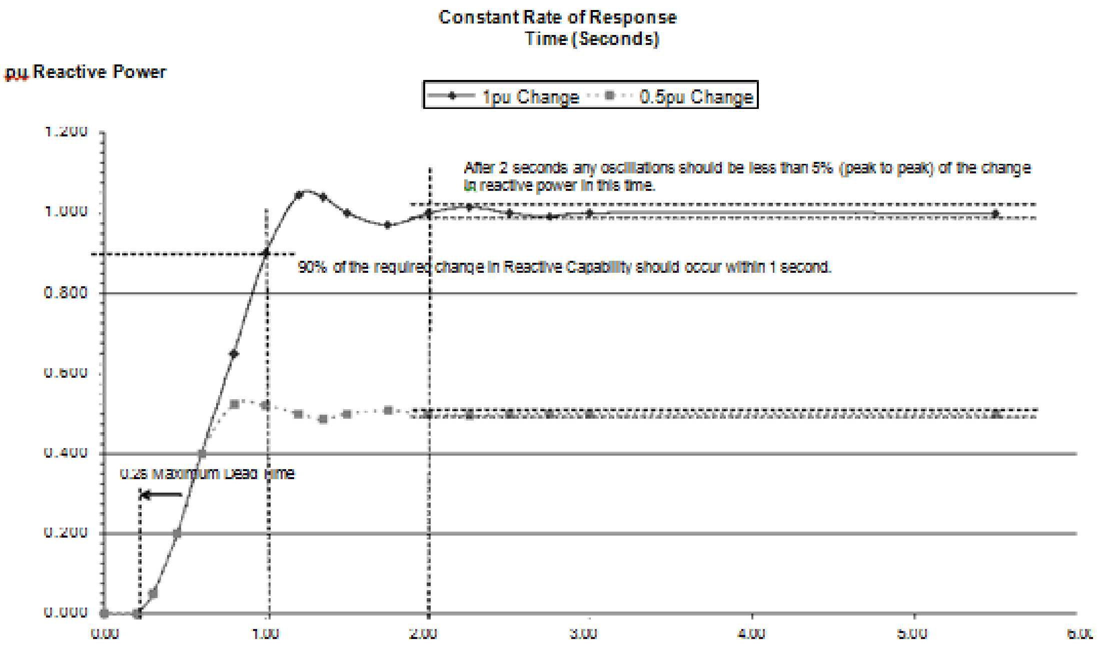


Figure B.1

Figure B.2 shows a control scheme which varies the rate of response proportional to the size of the step change.

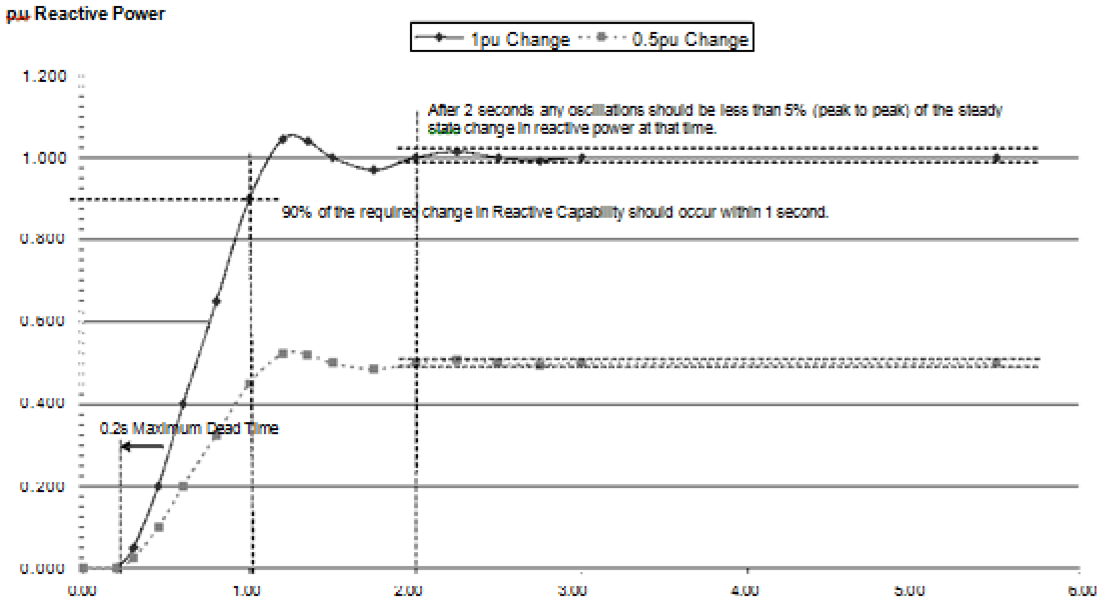


Figure B.2

Both Figures B.1 and B.2 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 shown above.

Compliance Test Description

The voltage control tests for a DC Converter are set out in Grid Code OC5.A.4.4. As described testing should be by tapping of an upstream grid transformer and by injection to the control system reference.

Where steps can be initiated using network tap changers, the DC Converter 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.

Suggested DC Converter Station Voltage Control Test Procedure

The following generic procedure is provided to assist DC Converter Stations in drawing up their own site specific procedures for the National Grid witnessed -DC Converter Voltage Control Tests.

Test	Step No	Description of Injection	Notes
		DC Converter in Voltage Control at Maximum Export/Import Power Output and near Unity Power Factor	
V1		• Record steady state for 10 seconds • Inject +1% step to Voltage Reference • Hold for at least 10 seconds • Remove injection as a step • Hold for at least 10 seconds	
V2		• Record steady state for 10 seconds • Inject -1% step to Voltage Reference • Hold for at least 10 seconds • Remove injection as a step • Hold for at least 10 seconds	
V3		• Record steady state for 10 seconds • Inject +2% step to Voltage Reference • Hold for at least 10 seconds • Remove injection as a step • Hold for at least 10 seconds	
V4		• Record steady state for 10 seconds • Inject -2% step to Voltage Reference • Hold for at least 10 seconds • Remove injection as a step • Hold for at least 10 seconds	

Test	Step No	Description of Tapchange	Notes
		DC Converter Station in Voltage Control at Maximum	
T1	1	• Record steady state for 10 seconds • Tap up 1 position on external upstream tap changer • Hold for at least 10 seconds	
	2	• Tap up 1 position on external upstream tap changer i.e. up 2 positions from starting position. • Hold for at least 10 seconds	
	3	• Tap down 1 position on external upstream tap changer i.e. up 1 positions from starting position. • Hold for at least 10 seconds	
	4	• Tap down 1 position on external upstream tap changer i.e. at starting position. • Hold for at least 10 seconds	

	5	• Tap down 1 position on external upstream tap changer i.e. down 1 positions from starting position. • Hold for at least 10 seconds	

	6	• Tap down 1 position on external upstream tap changer i.e. down 2 positions from starting position. • Hold for at least 10 seconds	
	7	• Tap up 1 position on external upstream tap changer i.e. down 1 positions from starting position. • Hold for at least 10 seconds	
	8	• Tap up 1 position on external upstream tap changer i.e. return to starting position. • Hold for at least 10 seconds	

Where the voltage control system includes discretely switched shunt capacitors/reactors to provide part of the reactive capability the test program should demonstrate the performance when these are switched.

Test	Step No	Description of Injection	Notes
		Adjust voltage setpoint to a suitable operating point below switching threshold for shunt device.	
V5	 9 10 11	• Record steady state for 10 seconds • Inject a step to the DC Converter Station Voltage Reference of sufficient size and polarity to switch in shunt device. • Hold for at least 10 seconds • Remove injection with a step of sufficient size to switch out the switched device • Repeat step 9 immediately (with minimum delay)	

Where switched devices are normally rotated, devices not required for the particular test should isolate to prevent their involvement.

Demonstration of Slope Characteristic

The DC Converter Station 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.

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, DC Converter Station Owners 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 File Structure (Part 3). Based on the information submitted, National Grid will meet with the DC Converter Station Owner 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 DC Converter Station voltage reference. The DC Converter Station Owner 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. Suggested
DC Converter PSS Test Procedure

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

Step No	Test	Injection	Notes
		DC Converter 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 Voltage Reference and hold for at least 10 seconds • Remove step returning 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 Voltage Reference and hold for at least 10 seconds • Remove step returning Voltage Reference to nominal and hold for at least 10 seconds	
7	3	• Inject band limited (0.2-3Hz) random noise signal into voltage reference and measure frequency spectrum of Real	
8		Power. • Remove noise injection.	
9		• Switch On Power System Stabiliser	
10	4	• Record steady state for 10 seconds	
11		• Inject +1% step to DC Converter Voltage Reference and hold for at least 10 seconds	
12		• Remove step returning Voltage Reference to nominal and hold for at least 10 seconds	
13	5	• Record steady state for 10 seconds	
14		• Inject +2% step to Voltage Reference and hold for at least	
		10 seconds	
15		• Remove step returning Voltage Reference to nominal and hold for at least 10 seconds	
16	6	• Inject band limited (0.2-3Hz) random noise signal into voltage reference and measure frequency spectrum of Real	
		Power.	
17		• Remove noise injection.	
18	7	• Increase PSS gain at 30second intervals. i.e. x1 – x1.5 – x2 – x2.5 – x3	

19		• Return PSS gain to initial setting	
		Repeat Voltage Control Tests with PSS in service.	

Appendix C - Frequency Control

Summary of Grid Code Frequency Control Requirements

The National Electricity Transmission System is an island network with no AC connections to mainland Europe. In order to manage the system frequency within the normal operating range 49.5 to 50.5Hz (CC.6.1.2) National Grid requires generating units and power park modules to be able to continuously modulate their output in relation to frequency across this range. In order to maintain a stable system frequency it is important that response from plant is achieved without undue delay.

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 DC Converter must be capable of maintaining a minimum level of active power (see Figure 2 of CC.6.3.3) in the frequency range 47Hz to 50.5Hz.

It also states CC6.3.3 (d) that when in Rectifier mode (acting as a demand) that active power exported from the system should reduce as system frequency falls below 49.5 Hz in line with figure 3, for ease replicated here as fig C1b Limited frequency Sensitive Mode Rectifier Mode operation.

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 drop 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.

Grid Code Figure CC.A.3.1 specifies a minimum requirement for frequency response of 10% of Registered Capacity achievable for Primary Secondary and High Frequency response. This minimum value is designed to ensure that plant provides a suitable contribution to maintain frequency correction when connected to the system and selected to Frequency Sensitive Mode (FSM) and response capability in excess of 10% is encouraged. The speed of response is an important criterion and the Grid Code Figures CC.A.3.2 and CC.A.3.3 indicate typical response from plant with no delay in response from the start of the frequency deviation.

Practically there is a permissible deadband and National Grid accepts a delay of up to but not exceeding 2 seconds before measureable response is seen from a generating unit in response to a frequency deviation.

BC3 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.

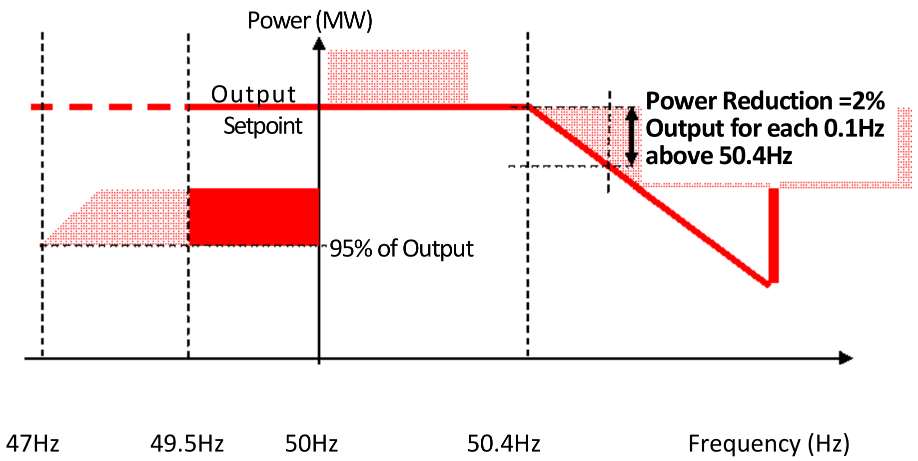
Details of the tests required for the preliminary and main governor response tests are provided in OC5.A.4.5 but additional guidance is provided in this Appendix including outline test procedures.

Modes of Frequency Control Operation

Balancing Code (BC) 3 of the Grid Code defines operation in Limited Frequency Sensitive Mode and Frequency Sensitive Mode. The requirements for these two modes differ depending on the direction of active power flow through the DC Converter.

When in Inverter mode exporting power onto the main GB network and in Limited Frequency Sensitive Mode the DC Converter 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. Should the frequencies rise above 50.4Hz it must reduce the active power output by a minimum of 2% of output for every 0.1Hz rise above 50.4Hz (see figure C1). Should this cause power output to be forced below Designed Minimum Operating Level (DMOL) then the DC Converter may disconnect after a time if operation is not sustainable.

Power/Frequency Characteristic for Limited Frequency Sensitive Mode



Grid Code	**CC.6.3.3,**	**BC.3.7.2**
References	**BC.3.5.2**	

Figure C1 – Limited Frequency Sensitive Mod Inverter Operations

When in Rectifier mode exporting power from the main GB network and in Limited Frequency Mode, the DC Converter is not required to change its export from the network should the frequency rise above 50 Hz. But should the frequency fall below 49.5 Hz export from the network should be decreased in accordance with figure C1b.

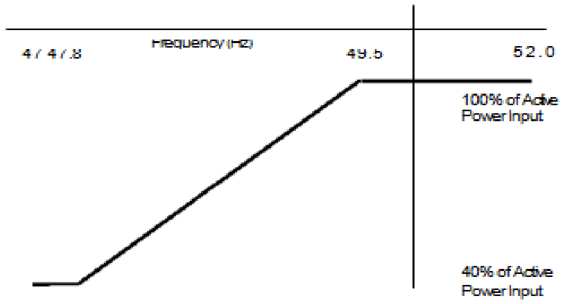


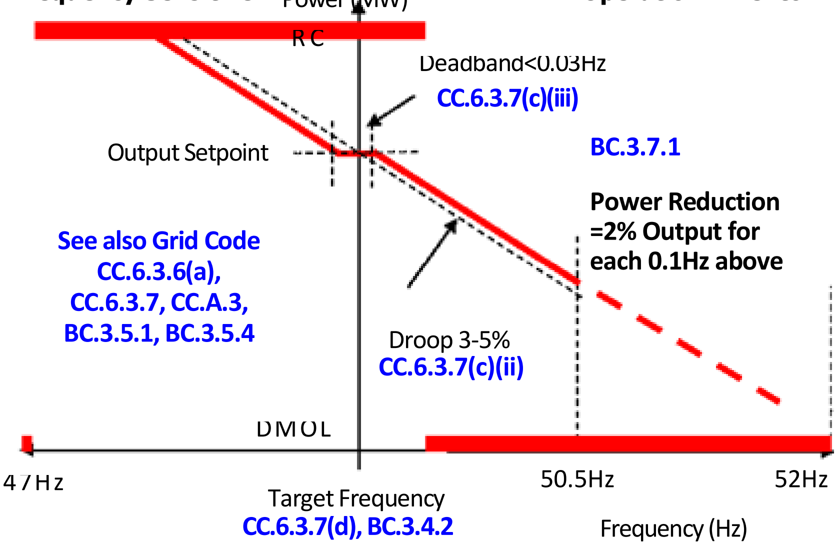
Figure C1b – Limited Frequency Sensitive Mode Rectifier Operation

When selected for Frequency Sensitive Mode by National Grid the DC Converter Station must adjust the active power output in response to any frequency change(within the range 49.5 Hz to 50.5 Hz) according to the agreed droop characteristic (between 35%). For the purposes of the Mandatory Services Agreement the frequency response performance is measured in terms of the response achieved after a given duration. Clearly there will be an Ancillary Services Agreement Frequency Response matrix for both directions of active power flow, 1. Inverter mode (import) and 2. Rectifier mode (export).

When system frequency moves outside of the range 49.5 Hz to 50.5 Hz the requirements of Limited Frequency Sensitive Mode apply.

Power/Frequency Characteristic for Frequency Sensitive Mode.

Figure C2 – Frequency Sensitive Operation Inventor Mode



Target Frequency

All Balancing Market Units (BMUs), irrespective of the plant type (wind, thermal, CCGT or DC Converter, whether directly Grid Connected or Embedded), are required to have the facility to set the levels of 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 Units 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.

De-load Instructions

System balancing is a separate issue to that of frequency response. A de-load instruction is to a fixed MW value rather than a delta MW value from available power. Typically Deloads may be instructed say from full output to enable both high and low frequency response to be available.

Summary of Steady State Load Accuracy Requirements

Grid Code CC.6.3.9 requires a DC Converter Station to be able to control output to a target with an accuracy specified as a standard deviation.

To demonstrate compliance, the DC Converter should self-dispatch for 30 minutes whilst in Limited Frequency Sensitive mode. The active power output and power available should be recorded with a sampling rate not less than once per minute.

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.

In order to verify the plant behaviour it is essential that the DC Converter 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. 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 shown in Grid Code OC5.A.4.5 Figures 1 and 2.

Typical Frequency Control Test Injection

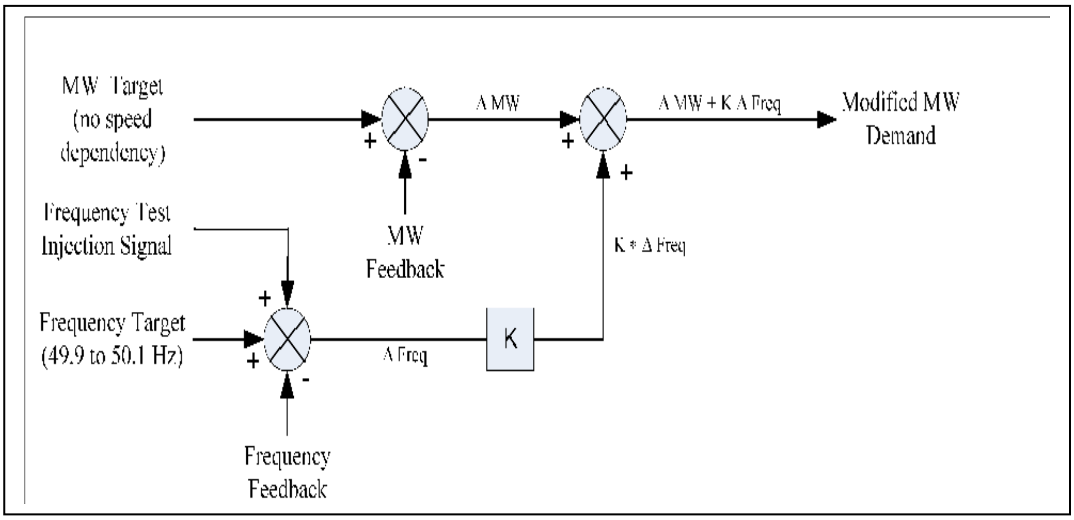
A frequency injection signal is needed to undertake all frequency related capability tests. Ideally the injected signal will be directly added into the raw frequency feedback as shown in the diagram below.

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.

Preliminary Frequency Response Testing

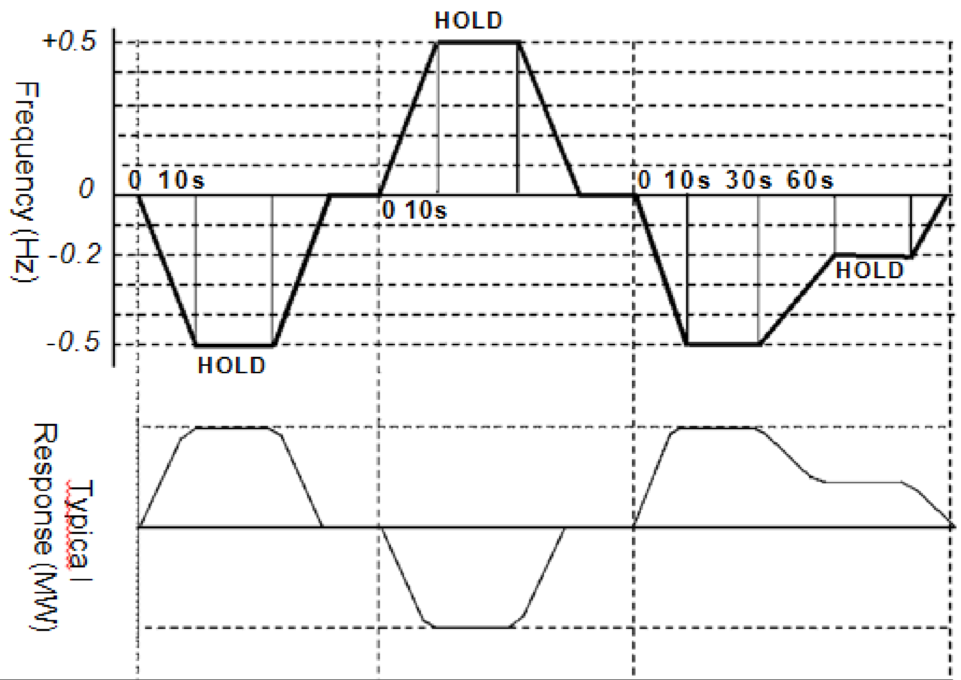
Past experience has demonstrated that significant delays can occur during testing because of problems associated with the frequency controller setup or frequency injection method. Frequently this results in considerable lost time and additional expense for both parties. Consequently this test has been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

Figure C4 Typical Frequency Test Injection Scheme



Typical injection locations at the frequency controller are shown in Figure C4. 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 DC Converter Station owner. A preliminary test is therefore required with details given in Grid Code OC5.A.4.5.4 and illustrated 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

For both Import and Export modes of operation, 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.



80% Load	-0.5Hz Ramp	+0.5Hz Ramp	LF Event Profile 1
	13	14	8

Figure C4 – Preliminary Frequency Response Test

The recorded results (e.g. Freq. injected, MW, Freq.sys) 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 2-3 minutes depending on the plant design).

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

National Grid Witnessed Frequency Response Testing Sequence

Grid Code OC5.A.4.5. Figure 1 and Figure 2 give 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). A full generic procedure is provided as an example.

1. **Establish Maximum Plant Capacity as Loading Point MLP6**

(a) manual and raise load demand to confirm the maximum output level at the base settings.
(b) Record plant and ambient conditions.

2. **Response Tests at Loading Point MLP6 (Maximum Output)**

(a) Operate the plant at MLP 6
(b) Inject ramp/profiled frequency changes simultaneously into the DC Converter controller (i.e. Tests 1-4 in OC5.A.4.5 Figure 1) and record plant responses.
(c) Conduct test BC1 – BC4 as shown in OC5.A.4.5 Figure 2 to establish the deloading capability as could occur under system islanding or system split conditions.

3. **Response Tests at Loading Point MLP5 (0.90 RC)**

(a) Operate the plant at MLP5.
(b) Conduct tests 5-7 as shown in OC5.A.4.5 Figure 1 and record plant responses.
(c) Conduct test A as shown in OC5.A.4.5 Figure 2 to establish the robustness of the control system under simulated extreme disturbances (as could occur under system islanding or system split conditions).

4. **Response Tests at Loading Point MLP4 (0.8 RC**)

(a) Operate the plant at loading point 4 (MLP 4).
(b) Conduct tests 8-14 as shown in OC5.A.4.5 Figure 1 and record plant responses.
(c) Conduct tests D - I as shown in OC5.A.4.5 Figure 2 to establish the DC Converter controller, and step response characteristics for DC Converter controller modelling purposes.
(d) Conduct test J as shown in Figure 2 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 (DMOL+20%)**

(a) Operate the plant at MLP3.
(b) Conduct tests 15 to 17 as shown in OC5.A.4.5 Figure 1 and record plant responses.

6. **Response Tests at Load Point MLP2 (DMOL+10%)**

(a) Operate the plant at MG.
(b) Conduct tests 18 - 22 as shown in OC5.A.4.5 Figure 1 and record plant responses.

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

(a) Operate the plant at DMOL.

(b) Conduct tests 23 - 26 as shown in OC5.A.4.5 Figure 1 and record plant responses.

(c) Conduct test K as shown in OC5.A.4.5 Figure 2 to establish the step response characteristics for DC Converter controller modelling purposes.

Generic Frequency Response Test Procedure

Since the governor response tests described above are to be arranged and conducted by the DC Converter Station owner, it is their responsibility to propose a test programme

to suit their site specific requirements. A typical example of the test procedure based on OC5.A.4.5 Figures 1 and 2 is given below. This procedure is required to be submitted to National Grid for approval before an ION is issued. The tests should be carried out in both export and import active power directions.

Initial Checks on Maximum Plant Capability at MLP6, Plant in LFSM	
Step	**Actions**
1	Record plant MLP 6 condition including levels for DC Converter Station MW import/export, ambient wind speed, and direction.
2	Change DC Converter controller to manual and increase output power demand to maximum.
3	Record plant conditions when plant is Stabilised.
4	Reset DC Converter controller to normal operating mode and allow MLP 6 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	+0.10Hz	
6		• Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 6	-0.10Hz	
7	2	• Inject -0.20Hz frequency fall over 10 sec • Hold until conditions stabilise	-0.20Hz	
8		• Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 6	+0.20Hz	
9	3	• Inject 0.20Hz frequency rise over 10 sec • Hold until conditions stabilise	+0.20Hz	
10		• Remove the injection signal over 10 sec	-0.20Hz	

		• Hold until conditions stabilise at MLP 6		
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	+0.50Hz -0.50Hz	
13 14	BC1	**Plant in FSM** • Inject +2.0* Hz frequency rise over 1 sec • Hold until conditions stabilise • Remove the injection signal • Hold until conditions stabilise at MLP 6	+2.0 Hz * -2.0 Hz	Part of for islanding CC.6.3.7 (c)(i)
15 16	BC2	Plant in FSM • 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 for BC.3.7.1

See Note 1	L	Plant in FSM • Record normal system variation in frequency and active power of the DC Converter over at least 10 minutes. Load setpoint at maximum.	No injection	Check for live frequency measurement
Switch to Limited Frequency Sensitive Mode				
17 18	BC3	**Plant in LFSM** • Inject +2.0* Hz frequency rise over 1 sec • Hold until conditions stabilise • Remove the injection signal	+2.0 Hz -2.0 Hz	Part of functionality test for islanding CC.6.3.7 (c)(i)
19 20	BC4	**Plant in LFSM** • Inject +0.6 Hz frequency rise over 30 sec • Hold until conditions stabilise • Remove the injection signal	+0.6 Hz -0.6 Hz	Part of functionality test for BC.3.7.2

* This will generally be +2.0Hz unless an injection of this size causes a reduction in plant output that takes the operating point below Designed Minimum Operating Level in which case an appropriate injection should be calculated in accordance with the following:

For example 0.9Hz is needed to take an initial output 65% to a final output of 20%. Calculation of the injected step should be as shown in the example given below

Initial Output	65%
Designed Minimum Operating Level	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 over 10 sec • Hold until conditions stabilise at MLP 5	-0.50Hz +0.30Hz	
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	-0.20Hz +0.20Hz	
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**	+0.50Hz -0.50Hz	
28 29	A	• Inject 1.0Hz/sec frequency fall over 2 sec • Hold for 30 sec • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 5	-2.0Hz +2.0Hz	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	-0.50Hz +0.30Hz +0.20Hz	
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	-0.10Hz +0.10Hz	
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	+0.10Hz -0.10Hz	
37	11	• Inject -0.20Hz frequency fall over 10 sec • Hold until conditions stabilise	-0.20Hz	

38		• Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 4	+0.20Hz	
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	+0.20Hz -0.20Hz	
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	-0.50Hz +0.50Hz	
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	+0.50Hz -0.50Hz	
45 46	D	• Inject -0.02Hz frequency fall as a step change • Hold until conditions stabilise • Remove the injection signal • Hold until conditions stabilise at MLP 4	-0.02Hz +0.02Hz	To assess the governor deadband
47 48	E	• Inject 0.02Hz frequency rise as a step change • Hold until conditions stabilise • Remove the injection signal • Hold until conditions stabilise at MLP 4	+0.02Hz -0.02Hz	To assess the governor deadband
49 50	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	-0.20Hz +0.20Hz	To assess step response characteristics of plant
51	G	• Inject 0.20Hz frequency rise as a step change • Hold until conditions stabilise	+0.20Hz	To assess step response
52		• Remove the injection signal • Hold until conditions stabilise at MLP 4	-0.20Hz	characteristics of plant
53 54	H	• Inject -0.50Hz frequency fall as a step change • Hold until conditions stabilise • Remove the injection signal • Hold until conditions stabilise at MLP 4	-0.50Hz +0.50Hz	To assess step response characteristics of plant
55 56	I	• Inject 0.50Hz frequency rise as a step change • Hold until conditions stabilise at MLP 4 • Remove the injection signal • Hold until conditions stabilise at MLP 4	+0.50Hz - 0.50Hz	To assess step response characteristics of plant
57 58	J	• Inject 1.0Hz/sec frequency fall over 2 sec • Hold for 30 sec • Remove the injection signal • Hold until conditions stabilise at OLP	-2.0Hz +2.0Hz	To assess plant performance under islanding and system split conditions

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See Note	M	• Record normal system variation in frequency and active power of the DC Converter over at least 10 minutes	No injection	
See Note 2	N	Plant in LFSM • Record normal system variation in frequency and active power of the DC Converter over at least 10 minutes	No injection	
Injection Tests at MLP 3, Plant in FSM				
59 60 61	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	-0.50Hz +0.30Hz +0.20Hz	
62 63	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	+0.50Hz -0.50Hz	
64 65 66	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	-0.80Hz +0.30Hz +0.50Hz	
Injection Tests at MLP2, Plant in FSM				
67 68 69	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	-0.50Hz +0.30Hz +0.20Hz	
		• Hold until conditions stabilise at MLP 2		
70 71	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	-0.20Hz +0.20Hz	
72 73	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	+0.20Hz -0.20Hz	

74 75	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	-0.50Hz +0.50Hz	
76 77 78	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 • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 2	-0.80Hz +0.30Hz +0.50Hz	

Injection Tests at MLP 1, Plant in FSM				
79 80 81	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	-0.50Hz +0.30Hz +0.20Hz	
82 83	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	-0.20Hz +0.20Hz	
84 85	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	+0.20Hz -0.20Hz	
86 87 88	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	-0.80Hz +0.30Hz +0.50Hz	
89 90	K	• Inject -0.5Hz frequency fall over 1 sec • Hold for 30 sec • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 1	-0.5Hz +0.5Hz	To assess plant performance under islanding and system split conditions

Tests L and M in OC5.A.4.5. Figure 2 should be conducted if the system frequency feedback signal is replaced by the injection signal rather than the injection signal being added to the system frequency signal. The tests simply consist of monitoring the DC

Converter output in Frequency Sensitive Mode during normal system frequency variations without applying any injection.

Test N in figure 2 should be conducted in all cases. All three tests should be conducted for a period of at least 10 minutes.

Control Requirements that may be witnessed

During attendance on site for witness testing of frequency response, National Grid may requresst5 that the DC Converter Station owner alters the Target Frequency sepoint from the DC Converter Station owners Control Room as an indication of controllability – this may be combined with tests M in OC5.A.4.5.

Appendix D - Other Technical Information

Technical Information on the Connection Bus Bar

This section illustrates the technical information relating to the connection bus bar that is provided by National Grid

Busbar on GB Transmission System operating at Supergrid Voltage: **Example 1** **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 DC Converter Point of Connection.	3.9	3.6	% on 100
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 DC Converter Station 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]

Equivalent Sequence Impedances For Calculating Unbalanced Short-Circuit Current Contribution

The DC Converter Station owner is required to provide the fault infeed from the DC Converter Station into the public transmission/distribution network. The data should be submitted in Grid Code DRC Schedule 14. The following transmission/distribution system equivalent sequence impedances may be used by the DC Converter Station owner in calculating unbalanced short-circuit current contribution from the DC Converter Station at the entry point unless site specific values have been given. The DC Converter

Station owner should confirm the system equivalent sequence impedances that have been used in the submission.

33kV: $Z1 = Z2 = 14.580\angle 88.091^{o}$ % on a 100 MVA base

$Z0 = 159.1\angle 26.565^{o}$ % on a 100 MVA base

These impedances are based on the following assumptions:

- The PPS and NPS X/R ratio of the 33kV system is equal to 30
- The ZPS X/R ratio of the 33kV system is equal to 0.5
- The short-circuit current contribution from the 33kV distribution system for a 3-phase fault at the entry point is approximately 12kA
- The short-circuit current contribution from the 33kV distribution system for a 1-phase fault at the entry point is approximately 3kA

132kV: $Z1 = Z2 = 3.650\angle 84.289^{o}$ % on a 100 MVA base

$Z0 = 1.460\angle 84.289^{o}$ % on a 100 MVA base

These impedances are based on the following assumptions:

- The PPS, NPS and ZPS X/R ratio of the transmission/distribution system is 10.
- The short-circuit current contribution from the transmission/distribution system for a 3-phase fault at the entry point is approximately 12kA
- The short-circuit current contribution from the transmission/distribution system for a 1-phase fault at the entry point is approximately 15kA

275kV: $Z1 = Z2 = 0.700\angle 85.236^{o}$ % on a 100 MVA base

$Z0 = 1.120\angle 85.236^{o}$ % on a 100 MVA base

These impedances are based on the following assumptions:

- The PPS, NPS and ZPS X/R ratio of the 275kV system is equal to 12

- The short-circuit current contribution from the 275kV transmission system for a 3-phase fault at the entry point is approximately 30kA
- The short-circuit current contribution from the 275kV transmission system for a 1-phase fault at the entry point is approximately 25kA

400kV: $Z1 = Z2 = 0.361\angle 85.914^{o}$ % on a 100 MVA base

$Z0 = 0.516\angle 85.914^{o}$ % on a 100 MVA base

These impedances are based on the following assumptions:

- The PPS, NPS and ZPS X/R ratio of the 400kV system is equal to 14
- The short-circuit current contribution from the 400kV transmission system for a 3-phase fault at the entry point is approximately 40kA
- The short-circuit current contribution from the 400kV transmission system for a 1-phase fault at the entry point is approximately 35kA

Appendix E - Contacting National Grid

There are a number of different parts of National Grid, each with key areas of expertise and responsibilities relevant to connection of a DC Converter Station. 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 can be found on the National Grid website.