Guidance Notes for HVDC

EU Code Users - Issue 3

April 2024

Foreword

These Guidance Notes have been prepared by the Electricity System Operator (ESO) to describe to HVDC or embedded HVDC system and other Users on the system how the Grid Code Compliance Processes is intended to work.

These Guidance Notes are prepared, solely, for the assistance of prospective HVDC connecting directly to the National Electricity Transmission System or an Embedded HVDC System (if the installation has a rating of 50MW or more).

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 6, Revision 23, effective from the 22 April 2024. They have been developed from Issue 1 of the Guidance Note of February 2013 and reflect the major changes brought about by Grid Code revision to facilitate compliance with the European Requirements for Generators and GC0141: Compliance Processes and Modelling amendments following 9th August Power Disruption.

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

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

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

David Lacey (Engineering Compliance Team Manager)

Telephone: 07548112092

Email: david.lacey@nationalgrideso.com

Faraday House, Warwick

Disclaimer: This document has been prepared for guidance only and does not contain all the information needed to comply with the specific requirements of a Bilateral Agreement with ESO. Please note that whilst these guidance notes have been prepared with due care, ESO does not make any representation, warranty or undertaking, express or implied, in or in relation to the completeness and or accuracy of information contained in these guidance notes, and accordingly the contents should not be relied on as such.

Contents

Abbreviations

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

Abbreviation	Description
AVC	Automatic Voltage Control (on transformers)
AVR	Automatic Voltage Regulator
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
CP	Compliance Processes
CSC	Current Sourced Converter
CUSC	Connection and Use of System Code
DC	Direct Current
DCS	Distributed Control System
DNO	Distribution Network Operator
DPD	Detailed Planning Data
DRC	Data Registration Code
ECC	European Connection Conditions
ECP	European Compliance Processes
EDL/EDT	Electronic Data Logging / Electronic Data Transfer
ELEXON	Balancing and Settlement Code Company
ESO	Electricity System Operator
FON	Final Operational Notification
FRT	Fault Ride Through
FSM	Frequency Sensitive Mode
GB	Great Britain
GCRP	Grid Code Review Panel
ION	Interim Operational Notification
LSFM(O)	Limited Frequency Sensitive Mode (Overfrequency)
LSFM(U)	Limited Frequency Sensitive Mode Underfrequency)
LON	Limited Operational Notification

MC	Maximum Capacity
MEL	Maximum Export Limit
MG	Minimum Generation
MLP	Machine Load Point
MRL	Minimum Regulating Level
MSOL	Minimum Stable Operating Level
NGET	National Grid Electricity Transmission
OC	Operating Code
OFGEM	Office of Gas and Electricity Markets
PC	Planning Code
PSS	Power System Stabiliser
PSSE	Power System Simulator for Engineering software
RfG	Requirements for HVDC or embedded HVDC system (EU legislation)
RISSP	Record of Inter System Safety Precautions
SEL	Stable Export limit
SO	System Operator (ESO)
SPT	Scottish Power Transmission
SHET	Scottish Hydro Electric Transmission
STC	System Operator Transmission Owner Code
TO	Transmission Owner
TOGA	Transmission Outages, Generation Availability
UDFS	User Data File Structure

Introduction

This document complements the European Compliance Processes (ECP) included in the Grid Code providing additional description of the technical studies and testing set out within the Grid Code. An alternative guidance note addresses the Compliance Processes (CP) for GB Users.

To achieve Operational Notification for the HVDC or embedded HVDC system, the company owning and operating, 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 ESO and the HVDC or embedded HVDC system 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 HVDC or embedded HVDC system are therefore the aggregation of those specified in the Grid Code and Bilateral Agreement.

For existing connections (connected prior to 8th September 2019) or who have placed purchase contracts for their main plant and apparatus prior to 28th September 2018 the HVDC or embedded HVDC system will be deemed a GB User and the new requirements in the European Connection Conditions (ECCs) will not apply. However, if an existing power station undertakes a significant modification to its plant or apparatus new requirements may become applicable.

The introduction of the ECC sections in the Grid Code introduced three new technical requirements for HVDC. These new areas are:

- Specification for Fast Fault Current Injection (FFCI) ECC.6.3.15.
- In addition, some requirements such as fault ride through were changed because of the RfG requirements.
- RMS & EMT Model submission and Compliance Repeat Plan subject to GC0141.

The compliance with these areas is discussed within this guidance note.

HVDC or embedded HVDC system may suggest alternative tests or studies, if they believe which will demonstrate compliance in accordance with the requirements placed on themselves and ESO.

Compliance Process

The process for HVDC or embedded HVDC systems to demonstrate compliance with the Grid Code and Bilateral Agreement are included in the Grid Code European Compliance Processes (ECP). In addition to the process and details of the documentation that is exchanged, the appendices to the ECP include the technical details of the simulation studies that a HVDC Owner should carry out (ECP.A.3) and the details of compliance tests applicable to HVDC or embedded HVDC system (ECP.A.7). The compliance processes cross reference with other sections of the Grid Code, namely the Planning Code (PC) and the European Connection Conditions (ECC). These are categorized as follows:

Category	Boundaries
Type A	≥800W to <1MW and connected below 110kV
Type B	≥1MW to <10MW and connected below 110kV
Type C	≥10MW to <50MW and connected below 110kV
Type D	≥50MW or connected at 110kV or above.

A power station as defined under the Grid Code would be classified as a large, medium, or small power station. This could comprise of any combination of a Type A, Type B, Type C or Type D power generating modules. A power station consisting of multiple power generating modules of different sizes may require a different compliance process approach for each module. Where a customer chooses, the process applicable to the largest module may be applied to smaller modules if this is agreed in advance with ESO.

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

Point of Compliance

In concept, the HVDC or embedded HVDC system defines the boundary at which compliance is demonstrated at the Grid Entry Point or User System Entry point if connected to a Distribution System. This is the ownership boundary between the HVDC Company assets and the public network. This is often the termination point in compact switchgear owned by a network licensee or a short cable owned by the HVDC system. In practical terms, if the cable has negligible impact on performance, then metering for HVDC Owner Control systems and signals for compliance assessment can be at the HVDC end of this short cable. If the cable is considered as having a material effect on performances, then control and signal metering needs to be at the network owner’s end of the cable. As a rule of thumb connection cables of less than 500m can be considered as negligible. Where cable lengths are significant line compensation may be considered as an alternative to taking signals directly from the connection point.

Compliance Repeat Plan

More updated guidance on Compliance Repeat Plan will be published on ESO website.

GC0141 has introduced the requirement for the User to restate compliance every 5 years from the issue of a FON (ECP.8). No later than 4 calendar years and 6 months after the issue of a FON, the ESO will notify the User to confirm continued compliance with the requirements of the Grid Code and/or the Bilateral Agreement. The User must confirm the compliance by submitting the following:

- A Compliance Statement and a User Self Certification of Compliance signed by the User. If there are any requirements that have not been met, then a statement of these should be submitted, together with a copy of the derogation.
- Details of any changes to relevant Planning Code data (both Standard Planning Data and Detailed Planning Data) and DRC schedules

In the case where all requirements have been satisfactorily fulfilled, the ESO will issue the User with a FON and the User can continue operation as before. In case of embedded plants, the notification will also be sent to the relevant Transmission Owner. However, in the case where requirements are not fulfilled and the User is deemed non-compliant, the ESO will issue a LON, and the relevant process will be followed. Some restriction may be imposed until the User resolves the issues.

Simulation Studies

The simulation studies described in the European Compliance Processes (ECP.A.3), and site tests described in Appendix A, B and C, provide indicative evidence that the requirements of the Grid Code have been met. However, if the study requirements specified in the Grid Code are inappropriate to the technologies employed on a particular project the HVDC owner should contact the ESO to discuss and agree an alternative program and success criteria.

In general, simulation studies are required to:

- Demonstrate an expected compliant performance ahead of connection.
- Demonstrate the model used is a true and accurate reflection of the plant, as built.
- Demonstrate capability where it is impractical through testing as the effects on other system Users would be unacceptable.

ECP.A.3 outlines simulation studies that are required to verify compliance with Grid Code requirements. The simulations must be based on the models submitted to ESO in accordance with Grid Code Planning Code Appendix section 5.4.2 (PC.A.5.4.2) except for the load rejection simulations in ECP.A.3.6.4 where a more complex model may be utilised if appropriate. Fault Ride Through studies are encouraged to be done using electromagnetic transient (EMT) models. Study reports must include verification and validation study as specified in ECP.A.3.7.

Simulations should be submitted in the form of a report (ECP.A.3.1.2) to demonstrate compliance in sufficient time to allow ESO to review and approve prior to ION.

Fault Ride Through and Fast Fault Current Injection requirement

The requirement applies for type B, type C and type D HVDC Owner. The principles and details of the requirement are set out in ECC.6.3.15 and ECC.6.3.16.

The HVDC owner shall provide time series simulation studies to demonstrate the capability of HVDC to meet the requirements described in ECP.A.3.5. It is to be noted that the Fault Ride Through studies are encouraged to be done in EMT models in order to assess the TOV impact on the power system.

Model Submission

To comply with the planning code requirements of the Grid Code, Users are required to provide to ESO, a validated model(s) which adequately represent the dynamic performance of their systems as demonstrated during the compliance process.

For connections in possession of a FON or an EON before the 1st of September 2022 the requirements detailed in PC.A.5.4.2 (a to h) of the Grid Code still apply.

For future connections, or those that had started the compliance process but had not received an EON by 1st September 2022 the modelling requirements detailed under PC.A.9 of the Grid Code apply.

For the avoidance of doubt, the User is also required to comply with any additional modelling requirements that might be included in the BCA, regardless of the planning code modelling section applicable to the connection.

For detailed recommendations and advice on the model(s) submission aimed at complying with PC.A.9 of the Grid Code please refer to “Guidance Notes on Modelling Requirements – GC0141 Grid Code Modification” by following the link below.

Guidance Notes on Modelling Requirements - GC0141 Grid Code Modification

Factory Acceptance Tests (FAT)

Factory Acceptance Tests, or FATs, are suggested to be conducted at the manufacturer’s site prior to the delivery and installation and these tests help to identify any issues and correct them prior to shipment. FAT test data can also be used as benchmark data to validate models and help facilitate the connection process. Similar process is adopted by DC connected windfarms.

Voltage Control, Frequency Control and Fault Ride Through tests can be witnessed in FAT. Following successful FATs of the Frequency Control tests, the onsite test procedure can possibly be simplified. The detailed scope can be discussed in the compliance process.

Compliance Tests

Tests identified in ECP.A.7 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 ECP.A.7 are in variant with the Bilateral Agreement or the test requirements are not relevant to the plant type, the HVDC Owner should contact the ESO 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 ECP.A.7. The HVDC owner is responsible for drafting test procedures for the power station as part of the compliance process prior to the issue of the Interim Operational Notification (ION). ECP.A.7 and the appendices of these guidance notes provide outline test schedules which may assist the HVDC Owner with this activity.

The ESO may require further compliance tests or evidence to confirm site-specific technical requirements (in line with the Bilateral Agreement) or to address compliance issues that are of particular concern. Additional compliance tests, if required, will be identified following ESO’s review of submissions of User Data File Structure (UDFS).

The tests are carried out by the HVDC owner, or by their consultants, and not by the ESO. However, the ESO may witness some of the tests as indicated in ECP.A.7. Tests should be completed following the test procedures provided in the UDFS prior to the issue of the ION unless otherwise agreed by the ESO.

The HVDC owner should also provide suitable digital monitoring equipment to record all relevant test signals needed to verify the HVDC system performance in parallel with the ESO recording equipment.

ESO Data Recording Equipment

ESO will provide a digital recording instrument on site during the tests witnessed by the ESO. A generic list of signals to be monitored during the ESO witnessed tests is tabulated in ECP.A.4.3. This will be used to monitor all plant signals at a sampling rate indicated in ECC.6.6.3. 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 ESO's recording equipment. For ESO purposes, the signals provided are required to be in the form of dc voltages within the range -10V to +10V (see ECC.6.6.3). The input impedance of the ESO equipment is in the region of 1MOhm and its loading effect on the signal sources should be negligible.

The station should advise the ESO of the signals and scaling factors prior to the test day. A form of a typical test signal schedule is shown in Table 1:

Signal	Unit	Voltage Range	Signal Representation
Active Power Output	MW	0 to 8V	0 to Reg. Capacity
Reactive Power Output	Mvar	-8V to +8V	- Reg Capacity to +Reg Capacity
Terminal Voltage	kV	0 to 8V	Nominal Voltage –10% to Nominal Voltage +10%
System Frequency	Hz	-8V to 8V	48.0Hz – 52Hz
List of other signals ……			

Table 1: A typical test signal schedule

ESO can set up the recording equipment on the day prior to the test date. The station representatives are asked to ensure that a 230V single phase 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 in Figure 1:

Figure 1: Example of Compliance Test Signal Connections

At sites where possible the person initiating the test injection signal (usually the manufacturer), the test co-ordinator (usually the owner) and the ESO monitoring signals should be in the same room to minimise co-ordination issues during witness testing.

The HVDC developer must inform the ESO if the signal ground (0V) is not solidly tied to earth or of any other potential problems which may have impact on the quality of the signals recorded.

With HVDC, where sometimes real time analogue signals cannot be exported, the Grid Code ECP.A.4.3.1(a) allows the basic signals to be provided directly from transducers connected to CTs/VTs on the interface circuit. 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. All the signals should then be available from the HVDC control systems as downloadable once the testing has been completed as described in ECP.A.4.3.1 (b) and (c).

Compliance Test Signals

The Grid Code requires that several signals are provided from compliance tests to the ESO to allow assessment of the compliance. The list of these signals is set out in ECP.A.4 for EU Code Users.

Where these signals are provided to the ESO it should be done in a consistent electronic format with a time stamp in a numerical format which can be interpreted in Excel. To facilitate efficient analysis, the test results should include signals requested by the ESO set out in the columns order as indicated in the tables in Appendix E.

- Signals for non-witness tests should be provided in excel format and in the order and format presented in Appendix E unless otherwise agreed, in advance, with ESO.
- Where any additional test signals to those indicated in the tables are presented these should only be added with the agreement of ESO and be entered within the files as additional columns to the right of the required signals.
- Where a signal cannot be provided, and this has been agreed with the ESO in advance of the tests, a blank column should be retained within the data.
- Where additional signals are included, or the signals are presented but not in the arrangement detailed above the data may be rejected and the customer will be asked to resubmit the data in the agreed format.

Compliance Test Log sheet

Where test results are completed without any ESO presence but are relied upon as evidence of the compliance they should be accompanied by a log sheet. This sheet should be legible, in English and detail the items set out in Appendix E.

Future Development of Compliance Testing

ESO recognises that organising of witness site tests can lead to delays in progressing connections through the compliance process. We are looking at options to deliver the same confidence while reducing the need to attend site and witness tests in the future. This would require the support of manufacturers and owners in several areas which are summarised below:

- A suitable interface which allows ESO a view of the key test parameters graphically in real-time from the ESO office. This would effectively provide the view of tests currently achieved by the ESO connecting its recording equipment while at site.
- Where ESO has decided to allow testing without real-time witnessing for compliance testing with lower materiality, such as repeat tests. In such circumstances manufacturers or developers must provide all the test data to ESO in the standard format set out in the guidance note complete with an appropriate test log sheet.
- Where ESO has decided that the design of a HVDC system and apparatus is standardised, and the compliance can be proved by providing evidence referring to a generic set of tests completed and accepted previously. The evidence can be Equipment Certificates where these have been accepted by ESO. This process will be followed provided that in ESO’s opinion it does not pose a material risk in terms of the specific site installations.

ESO will raise this during the compliance process and is open to suggestions from Developers. For manufacturers looking to suggest options or develop systems to facilitate remote witnessing please discuss with your compliance contact or contact ESO using the details in this guidance note.

Interim Operation

Prior to the issue of an Interim Operational Notification, the HVDC owner must submit a list of data to ESO to ESO's satisfaction, according to ECP.6.3.3.

It is also recommended to execute Voltage Injection tests under the STATCOM mode prior to full export/import tests.

Test Notification to Control Room

The HVDC Owner is responsible for notifying the 'ESO 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 'ESO Control Centre is detailed in OC.7.5 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 ESO's Internet site in Grid Code, Associated Documents.

The HVDC Owner should be aware that this interface with ESO transmission planning will normally be available in weekday working hours only. As best practice, the HVDC Owner should advise the 'ESO 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 and were possible with 28 days' notice. If there is insufficient notice or information provided by the HVDC Owner, then the proposed testing may not be allowed to proceed.

Protection Requirements

Under section ECC.6.2.2.2 of the Grid Code, the HVDC Owner must meet a set of minimum protection requirements. As part of the User Data File Structure content, the HVDC Owner should submit an HVDC Protection Settings report together with an overall trip logic diagram.

The HVDC Owner should provide details of all the protection devices 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
Control Trip Functions	Functional Description, Control Characteristic and trip settings
Islanding Protection (see below)	Type, description, settings and time delays

Islanding Protection

ROCOF protection should be disabled for directly connection and if islanding protection is required, an inter-tripping scheme is recommended. For Embedded generation, Islanding protection should be set in line with the G59/G99 requirement.

As stated in ECC.6.1.2, the System Frequency could rise to 52Hz or fall to 47Hz. The station must continue to operate within this Frequency range for at least the periods of time given in ECC.6.1.2, unless ESO has specified any other requirements. Station Owners will be responsible for protecting their equipment. If the frequency range is outside the range 52Hz to 47Hz, it is up to the Station Owner to decide whether to disconnect their apparatus in England and Wales, in Scotland shall be tripped according to the Grid Code.

Power Quality Requirements

For HVDC system 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 and Bilateral Agreement. The Transmission Owner is required to meet the relevant terms of the Grid Code.

With respect to harmonics, the Grid Code ECC.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 ECC.6.1.7 and/or Table 1 of Engineering Recommendation P28 issue 2 and therefore limits on voltage fluctuations are also specified in the relevant Bilateral Agreement. The HVDC system 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 issue 2 are used, with contribution from the HVDC system being calculated according to the International Electrotechnical Commission standard 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 HVDC system as detailed in Grid Code PC.A.6.4.2 should also be included giving due attention to tuned components.

For HVDC system 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.

A

Appendices

Appendix A: Reactive Capability

Summary of Requirements

The Reactive Capability requirements for HVDC system are specified in Grid Code ECC.6.3.2.

In summary, the first part of the requirement is for the HVDC system to be capable of operating with no reactive power transfer to the public power system (with a tolerance within +/-5% of active power output) from zero power output to full output. The second part of the requirement is for the HVDC system 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 is illustrated in the Figure ECC.6.3.2.4 (c).

Below 20% real power output, the HVDC system should continue to modulate reactive power transfer under voltage control. If there is a switch from voltage control to zero reactive power transfer control, the Grid Code requires that there is a smooth transition at active power output from above 20% to below 20% and vice versa.

Grid Code ECC.6.3.2.4.3 states that the reactive power capability must be fully available at all system voltages in the range ±5% of nominal. HVDC or embedded HVDC system connected at 33kV or below, are only required to meet the relaxed voltage/reactive capability envelope shown in Figure ECC.6.3.2.4(b). This relaxation recognises that the HVDC system developer does not have control of a transformer tap changer to control voltages within its network. The ECC.6.3.2.4.3 capability is not normally tested but is demonstrated by simulation.

In the event that during system incidents (i.e. the voltage is ≤95% or ≥105%) HVDC system should deliver the maximum (lagging or leading respectively) reactive power possible, while remaining within its design limits.

Contractual Opportunities Relating to Reactive Power Services

For HVDC system that can absorb and inject reactive power, there is an opportunity to provide an Enhanced Reactive Power Service (beyond the basic Obligatory Reactive Power Service) to help address the challenges of wider system voltage control. Developers interested in providing such service should take the opportunity of reactive capability testing to demonstrate this zero-power reactive capability. The delivery of reactive power is expected to be dynamic, i.e. responding to changes to system voltage in the same manner as normal operation.

Reactive Capability Compliance Tests

Grid Code ECP.A.6.4 describes the Reactive Capability testing. The required tests should demonstrate the maximum capability of the HVDC system beyond the corners of the envelope as shown in Grid Code Figure ECC.6.3.2.4 (c) 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 and should be carried out for both export and import mode.

The aim of the test is to capture performance of the HVDC at or as close to full active power output. Grid Code ECP.A.6.4.1 sets a minimum output level for carrying out the tests at least 85% of Registered Capacity. If the HVDC output is below this, the test should not be scheduled or attempted.

In order to demonstrate that HVDC system can satisfy the reactive capability requirements it is necessary to perform reactive capability tests as set out in ECP.A.7.2.5. An example of a corresponding test schedule is shown below.

Test No	Step	Description	Notes
1		• Operation at Maximum Capacity and maximum continuous lagging Reactive Power for 60 minutes	
2		• Operation at Maximum Capacity and maximum continuous leading Reactive Power for 60 minutes.	
3		• Operation at 50% Maximum Capacity and maximum continuous leading Reactive Power for 60 minutes.	
4		• Operation at 50% Maximum Capacity and maximum continuous lagging Reactive Power for 60 minutes.	
5		• Operation at Minimum Capacity and maximum continuous leading Reactive Power for 60 minutes.	
6		• Operation at Minimum Capacity and maximum continuous lagging Reactive Power for 60 minutes.	

Reactive Capability tests are not normally witnessed by ESO so where a HVDC Owner is recording the tests they should record details such as the HV system voltage and transformer tap position and equipment in service, as applicable, across the test period.

Appendix B Voltage Control

Summary of Requirements

The generic requirements for voltage control are set out in the Grid Code European 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 ECC.6.3.8 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 ECC Appendix 7 requires:

- ECC.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%.
- ECC.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%.
- ECC.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. Any oscillations (measured from peak to peak) should settle down to less than 5% of the change in steady-state reactive power within a further 5 seconds.
- ECC.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.
- ECC.A.7.2.2.6 The HVDC system must continue to provide voltage control through reactive power modulation within the designed capability limits over the full connection point voltage range +/-10% (ECC.6.1.4) however the full reactive capability (ECC.6.3.2.) is only required to be delivered for voltages within +/-5% of nominal in line with ECC.6.3.2 and ECC.A.7.2.2 or Figure ECC.A.7.2.2(b) if applicable.
- Grid Code Figure ECC.A.7.2.2(b) illustrates the operational envelope required.

The HVDC Owner must provide ESO with a transfer function block diagram illustrating the HVDC system 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 ESO to review the suitability of the proposed test programme to demonstrate compliance with the Grid Code.

Target Voltage and Slope

The ESO Control Centre issues voltage control instructions to all Balancing Market participants. For HVDC the usual instruction is to alter Target Voltage set point 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 HVDC 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 leading and lagging power factor usually at the Grid Entry Point or User System Entry Point if Embedded onshore HVDC system. Grid Code ECC.6.3.2.4.3 requires that the full Reactive Capability is capable of being delivered for voltages at the Grid Entry Point within ±5% of nominal.

Outside this voltage range the HVDC system 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, but plant must continue to provide maximum reactive power within its design limits.

Transient Response

The Grid Code ECC.A.7.2.3.1 sets out several criteria for acceptable transient voltage response. The Figure B.1 below illustrates responses that would be considered as being compliant with the Grid Code.

Figure B.1 illustrates an example of acceptable reactive power response under two on-load step changes. One results in a 1pu change and the other a 0.5pu change in reactive power output. For both cases, the dead time is less than 200ms and 90% of the reactive power output (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 within 1 second. The system settles, with the maximum oscillation in reactive power, in terms of peak-to-peak, limited to less than 5%, within 5 seconds.

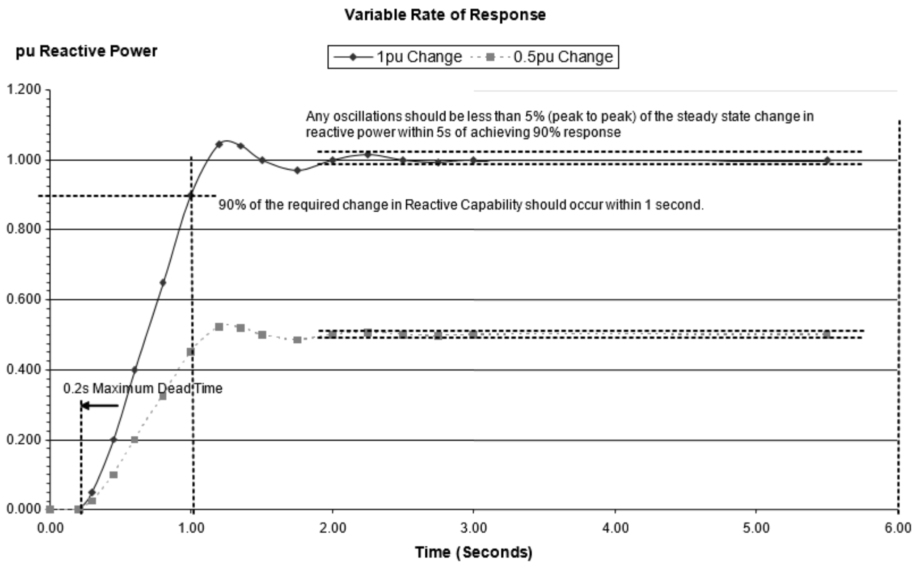


Figure B.1

Note: The Grid Code states that the reactive power 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 it will be acceptable.

Variations in Voltage Control Requirements

The Grid Code is continually reviewed by ESO 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.

Compliance Test Description

The voltage control tests for HVDC system are set out in Grid Code ECP.A.7.4. As described testing should be performed by both tapping of an upstream grid transformer (if applicable) and injection to the control system reference.

Where steps can be initiated using an upstream grid transformer tap changers, the HVDC Owner 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 HVDC system Voltage Control Test Procedure

The Voltage Test should be done when there is sufficient MW resource to import and export Maximum Capacity of the HVDC Equipment.

The following generic procedure is provided to assist HVDC or embedded HVDC system in drawing up their own site-specific procedures for the Voltage Control tests.

Test	Step No	Description of Injection	Notes
		HVDC system in Voltage Control at Maximum Power Output	
V1		• Record steady state for 10 seconds • Inject +1% step to HVDC Voltage Control System Setpoint • 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 HVDC Voltage Control System Setpoint	

		• 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 HVDC Voltage Control System Setpoint • 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 HVDC Voltage Control System Setpoint • Hold for at least 10 seconds • Remove injection as a step • Hold for at least 10 seconds	
V5		• Record steady state for 10 seconds • Inject +4% step to HVDC Voltage Control System Setpoint • Hold for at least 10 seconds • Remove injection as a step • Hold for at least 10 seconds	
V6		• Record steady state for 10 seconds • Inject -4% step to HVDC Voltage Control System Setpoint • Hold for at least 10 seconds • Remove injection as a step • Hold for at least 10 seconds	

Test	**Step No**	**Description of Tap change**	**Notes**
		HVDC system in Voltage Control at Maximum Power Output	
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	

If the HVDC system cannot provide voltage control down to zero active power, a test shall be carried out to demonstrate the smooth transition from voltage control mode to unity power factor control mode. In this case, the HVDC system voltage setpoint should be altered to increase its reactive power output or reduce its reactive power consumption at low active power level when voltage control is still used. Then the active power should be reduced to zero via a ramp over a short period (less than 60 seconds is suggested).

Demonstration of Slope Characteristic

The HVDC system voltage control system is required to follow a steady state slope characteristic. This should be demonstrated by recording voltage at the controlled busbar (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.

Appendix C Frequency Control

Summary of 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 (ECC.6.1.2.1.1) ESO requires generating units and HVDC to be able to continuously modulate their output in relation to frequency across this range. 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 several separate places, notably the Glossary & Definitions (GD), European Connection Conditions (ECC) and Balancing Code (BC) 3. This section summaries the key requirements.

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

ECC.6.3.3.1.1 of the Grid Code specifies that the HVDC system must be capable of maintaining a minimum level of active power (see Figure ECC.6.3.3(a)) in the frequency range 47Hz to 50.5Hz.

ECC.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.

Grid Code Figure ECC.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). Response capability more than 10% is encouraged.

The speed of response is an important criterion and the Grid Code (Figure ECC.A.3.2 and ECC.A.3.3) indicate typical responses from plant with no delay in response from the start of the frequency deviation. Practically there is a permissible dead time and ESO accepts a delay of up to but not exceeding 2 seconds before measurable 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 ECP.A.6.6 but additional guidance is provided in this Appendix including outline test procedures.

Modes of Frequency Control Operation

Balancing Code 3 (BC3) of the Grid Code defines operation in Limited Frequency Sensitive Mode and Frequency Sensitive Mode. HVDC system in LFSM mode are required to operate in LFSM at all times unless instructed by The Company to operate in FSM mode.

LFSM - O

Limited Frequency Sensitive Mode is the default mode used when not instructed by ESO to provide Frequency Response Services. In this mode the HVDC system is not required to provide any reduction in active power output if frequency increase over 50Hz but below 50.4Hz and is only required to maintain active power output in accordance with ECC.6.3.3. The rate of change of Active Power output must be at a minimum rate of 2 percent of output per 0.1 Hz deviation of System Frequency above 50.4Hz (i.e., a droop of 10%) as shown in Figure ECC.6.3.7.1 below. This would not preclude an HVDC system Owner from designing their Power Generating Module with a droop of less than 10% but in all cases the Droop should be 2% or greater. This is not an Ancillary Service, it is a European Connection Condition requirement for all HVDC system which have this capability. The HVDC are expected to meet LFSM-O requirement in both export and import mode.

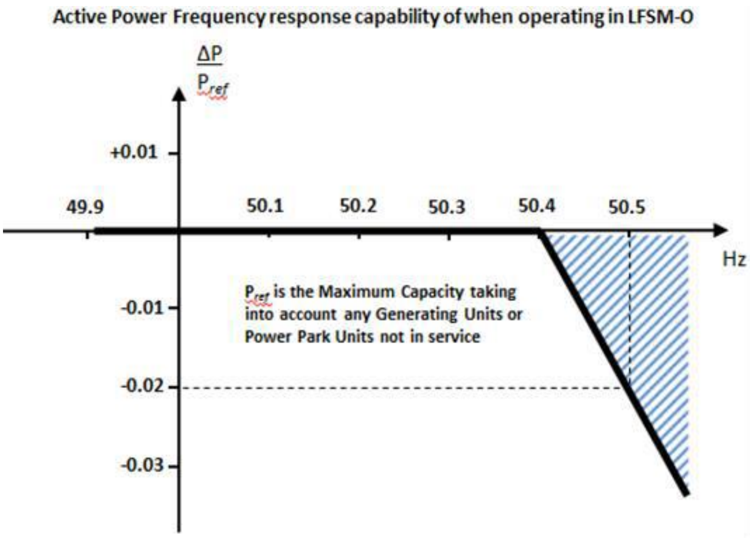


Figure C1 : active power response when operating in LFSM-O

LFSM-U

In this mode the HVDC system is not required to provide any increase in active power output if frequency reduces below 50Hz but above 49.5Hz and is only required to maintain active power output in accordance with ECC.6.3.3. However, the rate of change of Active Power output must be at a minimum rate of 2 percent of output per 0.1 Hz deviation of System Frequency below 49.5Hz (ie a Droop of 10%) as shown in Figure ECC.6.3.7.2.2 below. This is not an Ancillary Service, it is a European Connection Condition requirement for all HVDC system which have this capability. The HVDC are expected to meet LFSM-U requirement in both import and export mode.

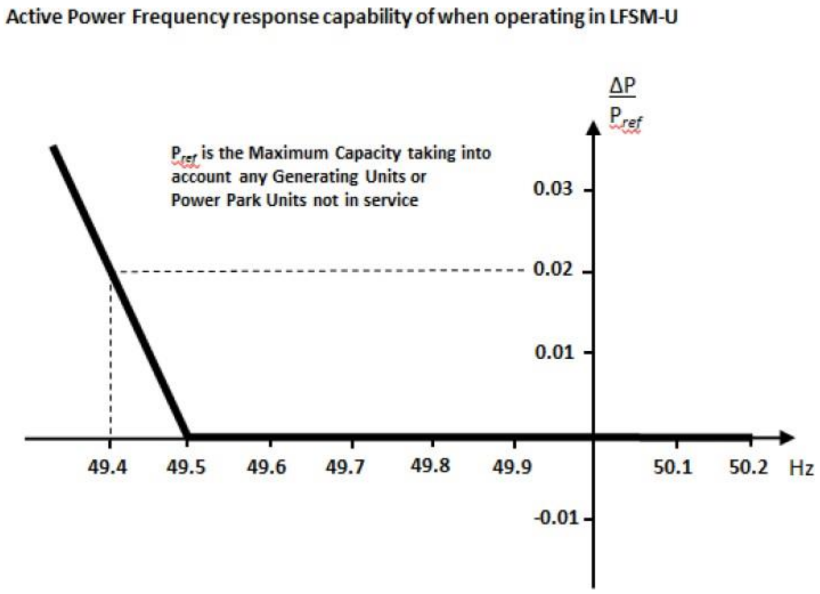


Figure C2 : Active power response when operating in LFSM-U import and export mode

FSM Mode

Frequency Sensitive Mode is used when selected to provide frequency response services. In this mode the HVDC system 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 HVDC system must further reduce output by a minimum of 2% of output for every 0.1Hz rise above 50.5Hz. To avoid the confusion, the control mode cannot be changed from FSM mode to LFSM mode unless instructed by ESO.

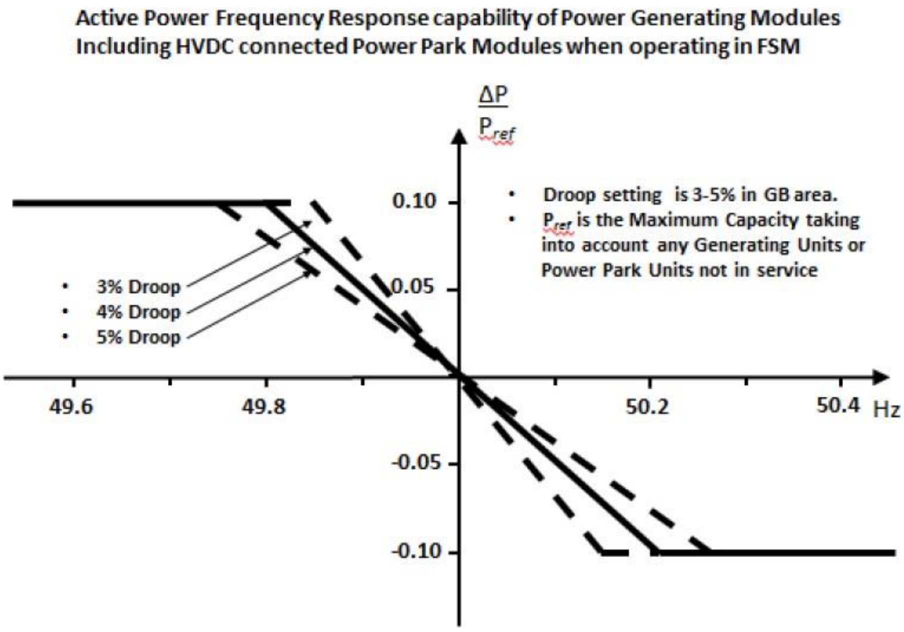


Figure C3 – Frequency Sensitive Mode

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 HVDC Owner output power and frequency. These are generally known as Target MW and Target Frequency settings.

The ESO Control Centre instructs all Active Balancing Market Unit to operate with the same Target Frequency, normally 50.00 Hz. 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.

This function is tested by stepping the Target Frequency setpoint from the main control point as indicated in ECP.A.7.5.9.

Steady State Load Accuracy Requirements

Grid Code ECC.6.3.9 requires HVDC system to be able to control output to a target with an accuracy specified as a standard deviation. To demonstrate compliance, the HVDC system should self-dispatch for 30 minutes at a load significantly below the Maximum Export Level (MEL). 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.

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 and feedback summing junction. The ramp of the descending frequency will be used to verify primary and secondary frequency response. Similarly, the ramp of the ascending frequency 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 ECP.A.7.5 Figures 1 and Figure 2. ECP.A.7.5. Figures 1 and 2 are shown for the generator mode (importing power into the UK grid), simulated frequency polarity should be reversed for the demand mode (exporting power from the UK grid). There should be sufficient time allowed between tests for control systems to reach steady state. A reasonable time gap is mandatory between test cases. According to ECP.A.7.5.8, it is suggested to have sufficient HOLD time, to allow the HVDC system to stabilise or be longer than 90 seconds, whichever is the longer. It is also suggested to leave sufficient gap between different test cases.

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 HVDC system frequency control strategy incorporates independent local frequency control at each HVDC system then the HVDC Owner 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 HVDC system controller network, so that if appropriate and applicable, injection can take place on a single HVDC system or the central controller.

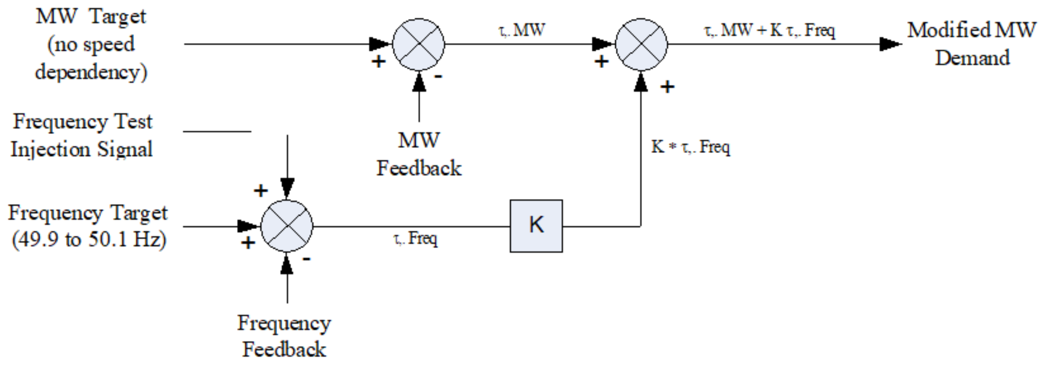


Figure C-4 Typical Frequency Test Injection Signal

Preliminary Frequency Response Testing

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

Typical injection locations at the frequency controller are shown in Figure C4. 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 HVDC system or site contractor. A preliminary test is therefore required with details given in Grid Code ECP.A.7.5.4 and illustrated below. For all tests, the target frequency selected on the generating plant is that instructed by the ESO Control Centre. This should normally be 50.00 Hz.

These tests should be scheduled at a time where there is sufficient MW resource in order to export full Maximum Capacity from the HVDC Equipment. The following frequency injections shall be applied when operating at module load point 4.

Preliminary Frequency Response Tests		
Test No	**Frequency Injection**	**Notes**
8	• Power output at MLP4 • Inject -0.50Hz frequency fall over 10 sec • Hold for a further 20 sec • Inject +0.30Hz frequency (increase) over 30 sec • Hold until conditions stabilise • Remove the injection signal as a ramp over 10 seconds	Plant in FSM
13	• Inject -0.50Hz frequency fall over 10 sec • Hold until conditions stabilise • Remove the injection signal as a ramp over 10 seconds	Plant in FSM

14	• Inject +0.50Hz frequency rise over 10 sec • Hold until conditions stabilise • Remove the injection signal as a ramp over 10 seconds	Plant in FSM
H	• Inject -0.50Hz frequency fall as a step change • Hold until conditions stabilise • Remove the injection signal as a step change	Plant in FSM
I	• Inject +0.50Hz frequency rise as a step change • Hold until conditions stabilise • Remove the injection signal as a step change	Plant in FSM

The recorded results (e.g. Freq. injected, MW and control signals) should be sampled at a minimum rate of 1 Hz to allow ESO 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 ESO for assessment at least two weeks prior to the final witnessed tests.

Frequency Response Testing Sequence

Grid Code ECP A.7.5 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). ECP.A.7.5. Figures 1 and 2 are shown for the Importing of Active Power, simulated frequency polarity should be reversed when exporting Active Power.

Grid Code ECP.A.7.5 Figure 3 gives the target frequency test requirement to demonstrate from the normal control point, typical load point is MLP4.

1. Establish Maximum Plant Capacity as Loading Point MLP6

(a) Switch HVDC system controller to 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 HVDC system controller (i.e. Tests 1-4 in ECP.A.6.6 Figure 1) and record plant responses.
(c) Conduct test BC1 – BC4 as shown in ECP.A.7.5 Figure 2 to establish the deloading capability as could occur under system islanding or system split conditions. Please note tests BC1, A, O & BC2 are FSM whilst tests BC3 & BC4 are LFSM.
(d) Conduct test L as shown in ECP.A.7.5. Figure 2 and record plant responses

3. Response Tests at Loading Point MLP4 (80% MEL)

(a) Operate the plant at loading point 4 (MLP 4).
(b) Conduct tests 8-17 as shown in ECP.A.7.5 Figure 1 and record plant responses.
(c) Conduct tests D - I as shown in ECP.A.7.5 Figure 2 to establish the HVDC system controller, and step response characteristics for HVDC system 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).

(e) Conduct test M as shown in ECP.A.7.5. Figure 2 and record plant responses

(f) Operate the plant at loading points 4 in Limited Frequency Sensitive Mode (MLP4 LFSM), conduct test BC5/BC6 as shown in ECP.A.7.5 Figure 2 to demonstrate LFSM-O and LFSM-U capability.

(g) Conduct test N as shown in ECP.A.7.5. Figure 2 and record plant response

4. Response Tests at Designed Minimum Operating Level MLP1 (MRL)

(a) Operate the plant at MRL.

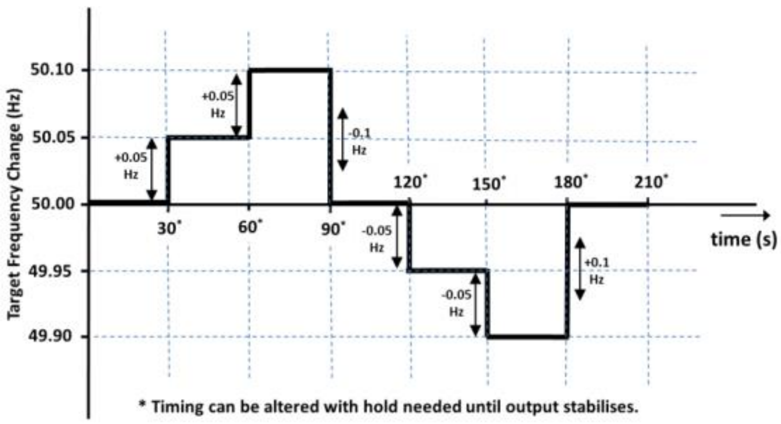
(b) Conduct tests 23 - 26 as shown in ECP.A.7.5 Figure 1 and record plant responses.

(c) Conduct test K and Q as shown in ECP.A.7.5 Figure 2 to establish the step response characteristics for HVDC system controller modelling purposes.

Target Frequency setting changes

During attendance on site for witness testing of frequency response, ESO will request that the HVDC Owner alters the Target Frequency setpoint from the HVDC or embedded HVDC system Control Room as an indication of controllability. The following test procedure indicates the steps of target frequency required in ECP.A.7.5.

=



ECP.A.7.5. Figure 3 – Target Frequency setting changes

Appendix D: Other Technical Information

Calculating Equivalent Impedance for Fault Ride Through Studies

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 minimum impedance can be derived from the maximum fault level at the connection point.

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

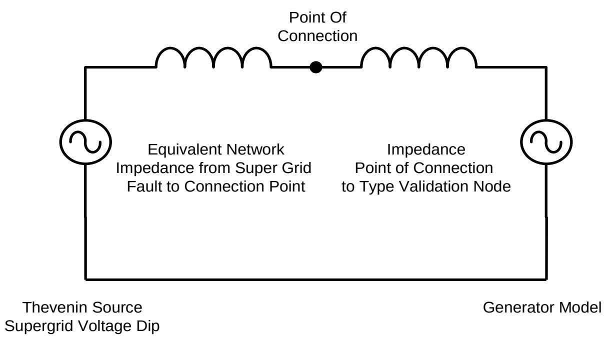
Positive Sequence Studies

The simplified positive sequence network below will generally be accepted as satisfying the 'pps' aspect of studies in Grid Code CP.A.3.5.

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 HVDC system 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 HVDC system 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.

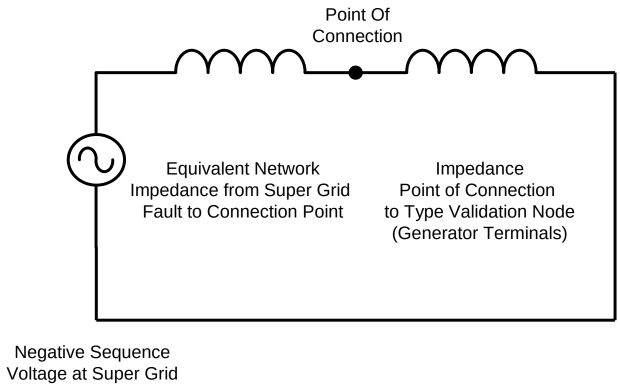


This simplified network can be implemented in a power system analysis package of the Developers choice using the voltage dips specified in Studies 3.1 & 3.2. The results at node 'A' are then compared to the type validation results to confirm ride through capability. The validity of the HVDC Owner model's 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'.

Negative Sequence Studies

Similarly, the simplified negative sequence network below will generally be accepted as satisfying the 'nps' aspect of Grid Code CP.A.3.5.

The negative sequence network is identical to the positive sequence network except that the HVDC Owner 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.

Technical Information on the Connection Bus Bar

This section illustrates the technical information relating to the connection bus bar that is provided by ESO or the host Transmission company.

Busbar on National Electricity 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 HVDC system Point of Connection.	3.9	3.6	% on 100 MVA
Total clearance time for fault on National Electricity Transmission System operating at Supergrid Voltage, cleared by System Back-up Protection (CC.6.2.2.2.2(b)	800		msec

Equivalent Circuit between Supergrid Busbar and HVDC system Point of Connection (showing transformer vector groups):

[Assume system ‘nps’ impedance pre-and post-fault such that ECC.6.1.6 limits met]

Equivalent Sequence Impedances for Calculating Unbalanced Short- Circuit Current Contribution

The HVDC Owner is required to provide the fault infeed from the HVDC system 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 HVDC Owner in calculating unbalanced short-circuit current contribution from the HVDC system at the entry point unless site specific values have been given. The HVDC 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 Test Signal Schedule and Log sheet

Compliance Test Signal Schedules

Compliance Test Signal Schedules **Table 1 - DC Converters Voltage Control**								
	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
1	Time (10ms)	Active Power	Reactive Power	Connection Voltage	Frequency #	Freq Injection #	Logic / Test Start#	Statcom #
	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16
1	State of Charge #	Current #	Voltage Setpoint #	Terminal Voltage if applicable #	DC converter owner tap position or Grid Transformer tap position, if applicable #	Control Mode #		
2								
# Columns may be left blank, but the column must still be included in the files								

Compliance Test Signal Schedules **Table 2 - DC Converters Reactive Capability**								
	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
1	Time (1s)	Active Power	Reactive Power	Connection Voltage	Frequency #	Freq Injection #	Logic / Test Start#	Statcom #
	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16
1	State of Charge #	Current #	Voltage Setpoint #	Terminal Voltage if applicable) #	DC converter owner tap position or Grid Transformer tap position, if applicable #	Control Mode #		
2								
# Columns may be left blank, but the column must still be included in the files								

Compliance Test Signal Schedules **Table 3 - DC Converters Frequency Control**								
	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
1	Time (100ms)	Active Power	Reactive Power #	Connection Voltage #	Frequency	Freq Injection	Logic / Test Start	Statcom #
	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16
1	State of Charge #	Current #	Voltage Setpoint #	Terminal Voltage if applicable #	DC converter owner tap position or Grid Transformer tap position, if applicable #	Control Mode #		
2								
# Columns may be left blank, but the column must still be included in the files								

Compliance Test Log sheet

Where test results are completed without any ESO presence but are relied upon as evidence of the compliance they should be accompanied by a log sheet. This sheet should be legible, in English and detail the items set out below. Some of the items listed may not be relevant to all technology type addressed by guidance notes.

- Time and Date of test
- Name of Power Station and module if applicable.
- Name of Test engineer(s) and company name.
- Name of Customer(s) representative and company name.
- Type of testing being undertake e.g., Voltage Control.
- Controller settings, e.g., Voltage slope, Frequency droop, Voltage setpoint.

For each test the following items should be recorded as relevant to the type of test being undertaken. Where there is uncertainty on the information to be recorded, this should be discussed with ESO in advance of the test.

Voltage Control Tests

- Start time of each test step.
- Active Power.
- Reactive Power.
- Connection Voltage.
- Voltage Control Setpoint, if applicable or changed.
- Voltage Control Slope, if applicable or changed.
- Terminal Voltage if applicable.
- DC converter owner tap position or Grid Transformer tap position, if applicable.

Reactive Power Capability Tests

- Start time of test.
- Active Power.
- Reactive Power.
- Connection Voltage.
- Terminal Voltage if applicable.

Frequency Response Capability Tests

- Start time of test.
- Active Power.
- System Frequency.
- Droop setting of controllers if applicable
- Frequency injection

Material changes during the test period should be recorded e.g., Unit’s tripping / starting, changes to tap changer positions. Thought should be given as to whether such changes invalidate the test, and a repeat test would be appropriate.

Appendix F: Contacting ESO

There are a number of different departments within ESO that will be involved with this connection. The initial point of contact for ESO will be your allocated Customer Connection Contract Manager for your Bilateral Agreement. If you are unsure of who your allocated Customer Connection Contract Manager is then the team can be contacted on box.ECC.Compliance@nationalgrideso.com.

For any correspondence relating to testing on the system following the Grid Code the IET process should be followed with notifications made to the '.Box.Tranreq' email address for England and Wales connections and '.Box.TR.Scotland' for all connections in Scotland.

Contact Address:

ESO, Faraday House, Warwick Technology Park, Gallows Hill, Warwick CV34 6DA

Faraday House, Warwick Technology Park,
Gallows Hill, Warwick, CV346DA
nationalgrideso.com

nationalgridESO