Guidance Notes for Electricity Storage

EU Code Users - Issue 3

October 2023

Foreword

These Guidance Notes have been prepared by the National Grid Electricity System Operator (ESO) to describe to Generators and other Users on the system how the Grid Code Compliance Processes is intended to work. Throughout this document National Grid refers to National Grid ESO (ESO) unless explicitly stated otherwise.

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

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

These Guidance Notes are based on the Grid Code, Issue 6, Revision 17, effective from the 4 September 2023. They reflect the changes brought about by Grid Code modification GC0148 (Implementation of EU Emergency and Restoration Code Phase II which includes Electricity Storage Modules operating in LFSM under importing conditions during low System Frequencies) as approved by the regulator in August 2023.

Definitions for the terminology used in 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:

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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)
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
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
NGESO	National Grid Electricity System Operator
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 Generators (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 an 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 Code Users.

To achieve Operational Notification, the Generator, the company owning and operating a Power Park Module, 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 Generator, which for technical reasons, may specify site specific requirements or parameters within a range indicated in the Grid Code. The total requirements placed on Generators are therefore the aggregation of those specified in the Grid Code and Bilateral Agreement.

The context of this guidance note is based on experience gained from wind turbines, but similar arrangements are expected to apply to other renewable technologies and Electrical Storage Modules. Separate documents exist for conventional synchronous plant and HVDC converter equipment.

For existing connections (connected prior to 27 April 2019) or who have placed purchase contracts for their main plant and apparatus before the 17th May 2018 the Generator will be deemed a GB Code 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 approval of Grid Code Modification GC0148 introduced the following new technical requirement for Electricity Storage Modules.

- LFSM - Frequency response requirements for operation in an import mode of operation during low system frequencies as per ECC.6.3.7.2.3

Compliance with these areas is discussed within this guidance note. Generators may, if they wish, suggest alternative tests or studies, which they believe will demonstrate compliance in accordance with the requirements placed on themselves and the ESO.

Compliance Process

The process for Generators to demonstrate compliance with the Grid Code and Bilateral Agreement is 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 Generator should carry out (ECP.A.3) and the details of compliance tests applicable to Electricity Storage Modules (ECP.A.6). The compliance processes cross reference with other sections of the Grid Code, namely the Planning Code (PC) and the European Connection Conditions (ECC). The technical requirements for a power generating module is based on its size at the connection point. A Power Generating Module is defined in the Grid Code but, for the purposes of this document, the emphasis is placed on Electricity Storage Modules. 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 any combination of 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 the ESO.

The PC sets out the data and information that a Generator 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).

The ECC sets out the majority of the technical design requirements that a Generator is required to meet with site specific variations laid out in the Bilateral Agreement.

The ECP sets out the technical details of the tests and simulations which the ESO requires to demonstrate compliance with the Grid Code.

Point of Compliance

In concept, Generators define 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 Generating Company assets and the Grid System. Where a cable is owned by a Generator between its main Plant and Apparatus and the Grid Entry Point or User System Entry Point, and the cable has negligible impact on performance, then metering for Generator Control systems and signals for compliance assessment can be at the Generator end of this short cable. If the cable is considered as having a material effect on performance, then control and signal metering needs to be at the Network Operator'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

Grid Code Modification GC-0141 has introduced the requirement for users to restate compliance every 5 years, from the issuance of FON (ECP.8). Before the 5 year period from issue of the FON, the ESO will notify the User to confirm continued compliance. To do so, the User will be required to submit the following:

1) 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, together with a copy of the derogation.
2) 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. It may be that some restriction is imposed until the User resolves the issues. The Compliance Repeat Plan shall not be applicable for Embedded Small Power Stations, in which case the responsibility shall lie with the relevant Distribution Network Operator.

Simulation Studies

The simulation studies described in the European Compliance Processes (ECP.A.3), and Electrical Storage Unit type 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 Generator should contact the ESO to discuss and agree an alternative program and success criteria.

In general, simulation studies are required to,

1) demonstrate an expected compliant performance ahead of connection.
2) demonstrate the model supplied is a true and accurate reflection of the plant, as built.
3) demonstrate capability where it is impractical through testing as the effects on other system Users would be unacceptable.

The simulations must be based on the validated models supplied to the ESO in accordance with Grid Code Planning Code Appendix A section 5.4.2 (PC.A.5.4.2) and be submitted before issuing an ION. Fault Ride Through studies are encouraged to be done using electromagnetic transient (EMT) models.

Fault Ride Through and Fast Fault Current Injection requirement

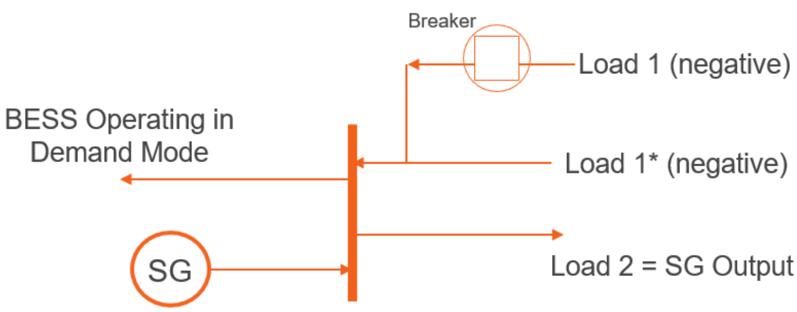
The requirement applies for type B, type C and type D Power Park Modules. The principles and details of the requirement are set out in ECC.6.3.15 and ECC.6.3.16.

The Electrical Storage User shall supply time series simulation study results to demonstrate the capability of the Electricity Storage module to meet the requirements by submission of a report described in ECP.A.3.5. Please note, the fault ride through studies are expected to be carried out using an EMT simulation tool in order to assess the TOV impact on the power system.

Operation in Demand Mode

For operation of Electricity Storage Modules during low frequency operation, please refer to the simulation requirements in ECP.A.3.6.9, ECP.A.3.6.10, ECP.A.3.6.11 and ECP.A.3.6.12.

There are additional requirements for Load Rejection in Demand mode as follows (please also refer to ECP.A.3.6.7).



Load Rejection Simulations

1. The Electricity Storage Module should initially be operating at zero Active Power output and have sufficient capability so that it is possible to operate the Electricity Storage Module at Maximum Capacity and Maximum Import Power. The simulation studies as detailed in ECP.A.3.6.1 – ECP.A.3.6.6 should

then be conducted to ensure the Electricity Storage Modules Active Power output achieves its Maximum Import Power in line with the Droop and response time settings as declared by the Generator.

2. The Electricity Storage Module should be operating at 50% of its Maximum Import Power and have sufficient capability so that it is possible to operate the Electricity Storage Module at Maximum Capacity and Maximum Import Power. The simulation studies as detailed in ECP.A.3.6.1 – ECP.A.3.6.6 should be conducted to ensure the Electricity Storage Modules Active Power output achieves its Maximum Import Power in line with the Droop and response time settings as declared by the Generator.

   a. *Example: Consider a 100MW BESS Power Station. At the start of the simulation, BESS would be importing 50MW, SG would be generating enough only to match Load 2. Load 1* is -50MW and Load 1 is at -0.5pu (i.e. -50MW). Once the breaker is closed, Load 1 gets connected to the busbar due to which the frequency of this system increases. BESS would react to this frequency change and start importing the active power from -50MW to maximum import capacity i.e. -100MW*

3. The Electricity Storage Module should be operating at its Maximum Import Power. The simulation studies should be conducted to ensure the Electricity Storage Modules Active Power remains at its Maximum Import Power unless it is in Frequency Sensitive Mode and the tested Frequency falls below 50.5Hz.

   a. *For this simulation, the SG shall act in governor control mode. At start of the simulation, BESS would be importing 100MW (-1pu for a 100MW BESS PPM). Load 1* is -1pu (-100MW for a 100MW BESS PPM) and Load 1 is -10MW (or some negative load sufficient to cause frequency rise). Once the breaker is closed, Load 1 is connected to the busbar due to which the frequency of this system increases. BESS should NOT react to this frequency change as it is already importing at maximum capacity. Therefore, SG should react to control the frequency change and reduce its power output.*

Validated Models

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

The model structure and complexity must be suitable for ESO to integrate into their power system analysis software (currently DigSilent). As a general rule, time constants less than 10ms should be avoided. In cases where the model's functionality cannot be correctly or satisfactorily represented within the ESO's power system analysis software, the Generator may be required to liaise with the ESO to determine an appropriate interpretation.

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

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

According to Grid Code modification GC0141, projects with a completion date after 1 September 2022 and any Power Park Units subject to a control system change or modification after 1 September 2022 need to supply EMT models, in addition to RMS models in accordance with the requirements Grid Code PC.A.9.

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

The ESO encourages developers to work with manufacturers to develop the use of standard models for each type of Electricity Storage Module. It is the responsibility of the Generator to provide information as described in the Planning Code, which enables the ESO to model the National Electricity Transmission System.

Refer to Guidance on EMT Models and Guidance for Model Exchange on ESO's website for more information on these subjects.

Compliance Tests

Tests identified in ECP.A.6 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.6 are at variance with the Bilateral Agreement or the test requirements are not relevant to the plant type, the Generator 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.6. The Generator 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.6 and the appendices of these guidance notes provide outline test schedules which may assist the Generator 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 Generator, or by their agent, and not by the ESO. However, the ESO may witness some of the tests as indicated in ECP.A.6. Tests should be completed following the test procedures supplied in the UDFS prior to the issue of the ION unless otherwise agreed by the ESO.

The Generator should also provide suitable digital monitoring equipment to record all relevant test signals needed to verify the Electrical Storage 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 power 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 power 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 below:

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 2 : A typical test signal schedule

It may be appropriate for the ESO to 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 the following picture:

Figure 1 – Example of Compliance Test Signal Connections

At sites where there are multiple Electricity Storage Modules it may be advantageous for the Electrical Storage developer to cable the signals for several Electricity Storage Modules to a single point. Where possible the person initiating the test injection signal (usually the manufacturer), the test co-ordinator (usually the owner) and the ESO monitoring the signals should be in the same room to minimise the risk of errors during witness testing.

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

With Electricity Storage Modules, where sometimes real time analogue signals cannot be outputted from the control scheme, the Grid Code ECP.A.4.3.1(a) allows for the basic signals to be supplied 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 Electricity Storage Module control systems as a download once the testing has been completed as described in ECP.A.4.3.1 (b) and (c).

The four basic signals are:

1. Total MW
2. Total MVAr
3. Point of connection line-line Voltage (HV) (kV)
4. System frequency (Hz)

Compliance Test Signals

The Grid Code requires that several signals are provided from compliance tests to the ESO to allow assessment of 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 Logsheet

Where test results are completed without any ESO presence but are relied upon as evidence of compliance, they should be accompanied by a logsheet. 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 a number of areas which are summarised below:

1) A suitable interface which allows ESO a view of the key test parameters graphically in real-time from the ESO office in Warwick. This would effectively provide the view of tests currently achieved by the ESO connecting its recording equipment while at site.

2) 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 the ESO in the standard format set out in the guidance note complete with an appropriate test logsheet.

3) Where ESO has decided that the design of a Electricity Storage Modules and apparatus is standardised and compliance can be evidenced by reference to a generic set of previously completed and accepted tests(this could include the use of agreed Equipment Certificates by the ESO) this process will be offered provided 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 are 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

As there may be a considerable period between commissioning the first and last Electrical Storage Unit within a module, the Grid Code European Compliance Processes (ECP) provides two capacity restrictions during commissioning. These restrictions are managed by items included in the Interim Operation Notification (ION). The Generator is required to complete basic voltage control and frequency response tests and have the results approved by ESO in order to have the capacity restrictions released.

Test Notification to Control Room

The Generator 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 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 ESO's Internet site in Grid Code, Associated Documents.

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

Protection Requirements

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

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

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

Islanding Protection

If islanding protection is required, an inter-tripping scheme is recommended by G59/G99. If 'Rate of Change of Frequency' (ROCOF) trip relays are to be considered, there could be compliance implications which need to be discussed with the ESO at the earliest opportunity. ESO does not require or desire Generators to fit ROCOF protection but needs to be consulted on the settings of any such protections in service. Vector Shift protection is no longer accepted.

Power Quality Requirements

For Electrical Storage 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 G5/5. The Grid Code further requires that the planning criteria contained within Engineering Recommendation G5/5 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 Electrical Storage 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 G5/5 is applied. For the voltage fluctuation, the principles outlined in Engineering Recommendation P28 issue 2 are used, with contribution from the Electricity Storage Module 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 Electrical Storage as detailed in Grid Code PC.A.6.4.2 should also be included giving due attention to tuned components.

For Electricity Storage Modules 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 Electricity Storage Modules are specified in Grid Code ECC.6.3.2.

In summary, the first part of the requirement is for the Electricity Storage Module to be capable of operating with zero 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 Electricity Storage Module 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 Electricity Storage Module 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%.

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. Generators 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 Electrical Storage developer does not have control of a transformer tap-changer to control voltages within his 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 $\leq$95% or $\geq$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) covering the period when the renewable energy source is not available. Developers interested in providing such a service should take the opportunity of reactive capability testing to demonstrate this zero power reactive capability. The delivery of reactive power would be expected to be dynamic, i.e. responding to changes to system voltage in the same manner as normal operation.

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 Electricity Storage Module 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 Electricity Storage at or as close to full output. Grid Code ECP.A.6.4.1 sets a minimum power output level for carrying out the tests of 85% of Registered Capacity. If the Electricity Storage output is below this, the test should not be scheduled or attempted.

In order to demonstrate that Electrical Storage can satisfy the reactive capability requirements it is necessary to perform reactive capability tests as set out in ECP.A.6.4.5. An example of a corresponding test schedule is shown below.

Test No	Step	Description	Notes
1		• Plant in Voltage Control Initial operation must be in excess of 85% Maximum Capacity • Operation in excess of 60% Maximum Capacity • Target Voltage (*) selected to generate a maximum continuous lagging Reactive Power for 30 minutes.	
2		• Initial operation must be in excess of 85% Maximum Capacity • Operation in excess of 60% Maximum Capacity • Target Voltage (*) selected to generate a maximum continuous leading Reactive Power for 30 minutes.	
3		• Operation at 50% Maximum Capacity • Target Voltage (*) selected to generate a maximum continuous leading Reactive Power for 30 minutes.	
4		• Operation at 50% Maximum Capacity • Target Voltage (*) selected to generate a maximum continuous lagging Reactive Power for 30 minutes	
5		• Operation at 20% Maximum Capacity • Target Voltage (*) selected to generate a maximum continuous leading Reactive Power for 60 minutes.	
6		• Operation at 20% Maximum Capacity • Target Voltage (*) selected to generate a maximum continuous lagging Reactive Power for 60 minutes.	
7 (Note 1)		• Operation at less than 20% Maximum Capacity and unity Power Factor for 5 minutes. • This test only applies to systems which do not offer voltage control below 20% of Maximum Capacity	
8 (Note 2)		• Operation at the lower of the Minimum Regulating Level or 0% Maximum Capacity and maximum continuous leading Reactive Power for 5 minutes. • This test only applies to systems which offer voltage control below 20% and hence establishes actual capability rather than required capability.	
9 (Note 2)		• Operation at the lower of the Minimum Regulating Level or 0% Maximum Capacity and maximum continuous lagging Reactive Power for 5 minutes. • This test only applies to systems which offer voltage control below 20% and hence establishes actual capability rather than required capability.	

(*) Target Voltages may need to be changed regularly in order to generate the maximum continuous lagging/leading reactive power for 60 minutes.

Notes

1. If the Electricity Storage Module does not provide voltage control below 20% active power output, then test 7 should be carried out to demonstrate smooth transition to within the required reactive power envelope.
2. If the Electricity Storage Module provides voltage control down to zero active power output, then tests 8 and 9 should be performed

Reactive Capability tests are not normally witnessed by the ESO so where a Generator 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 system 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 Electricity Storage Module 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 Generator must provide the ESO with a transfer block diagram illustrating the Electricity Storage Module's 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 the 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 Electricity Storage Modules 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 Generator 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 lead/lag at rated MW output, usually at the Grid Entry Point or User System Entry Point if Embedded onshore Electrical Storage. 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 Electricity Storage Module must be capable of continuing to contribute to voltage control by delivering Reactive Power. However, the level of reactive power delivered may be limited by the design of the plant and apparatus. There is no low or high limit on this obligation, plant must continue to provide maximum reactive power within its design limits.

Transient Response

Grid Code ECC.A.7.2.3.1 sets out a number of criteria for acceptable transient voltage response. The Figure below illustrate responses that would be considered as meeting the Grid Code.

Figure B.1 illustrates a control scheme example of acceptable responses. The graph shows the response to two steps, one to initiate a 1pu and the other a 0.5pu change in reactive capability. The graph shows how the change can allow the system to achieve the objective. In this case, the dead time is less than 200ms and 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. The system settles, with the maximum oscillation in reactive power, in terms of peak-to-peak, limited to less than 5% of the change in steady-state reactive power, within 5 seconds.

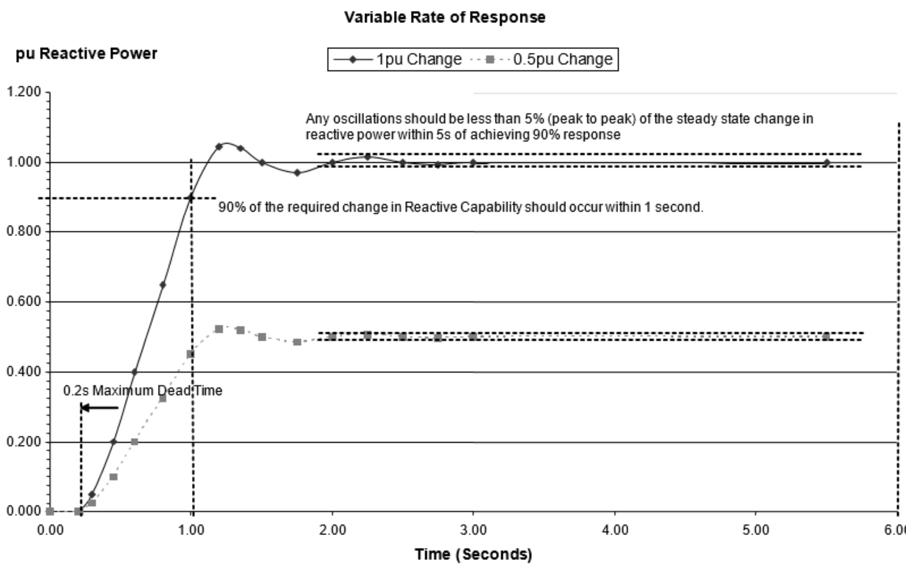


Figure B.1

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 it will be acceptable.

Variations in Voltage Control Requirements

The Grid Code is continually reviewed by the 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 Electricity Storage Modules are set out in Grid Code ECP.A.6.5. As described, testing should be by tapping of an upstream grid transformer and also by injection to the control system reference.

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

Suggested Electrical Storage Voltage Control Test Procedure

The Module Test should be done when 95% of the Electricity Storage Units and any reactive compensation units are in service. Allowing power production from the Module of at least 65% Registered Capacity. The tests need to be carried out for both import mode and export mode.

The following generic procedure is provided to assist Generators in drawing up their own site-specific procedures for the ESO Module Voltage Control Tests. The ESO may ask for steps to the Voltage Reference greater than those shown below within the guidelines of Engineering Recommendation P28.

Test	Step No	Description of Injection	Notes
		Electrical Storage in Voltage Control at Maximum Power Output (>65% Rated MW) and near Unity Power Factor	
V1		• Record steady state for 10 seconds • Inject +1% step to Electrical Storage 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 Electrical Storage 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 Electrical Storage 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 Electrical Storage Voltage Reference • 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 Power Park Module Voltage Reference • 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 Power Park Module 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
		Electrical Storage in Voltage Control at Maximum Power Output (>65% Rated MW) and near Unity Power Factor	
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	

In the case of Electricity Storage Modules that do not provide voltage control down to zero Active Power a test to demonstrate the smooth transition from voltage control mode to unity Power Factor shall be carried out. The Electricity Storage Module voltage setpoint should be altered to produce lagging Reactive Power or absorbing leading Reactive Power at a low Active Power level where voltage control is provided. The Electricity Storage Module Active Power output should then be reduced to zero Active Power as a ramp over a short period (60 seconds is suggested)

Where the voltage control system includes either discretely switched shunt capacitors/reactors or bias capacitors 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.	
V7	1	• Record steady state for 10 seconds • Inject a step to the Electrical Storage Voltage Reference of sufficient size and polarity to switch in shunt device. • Hold for at least 10 seconds	
	2	• Remove injection with a step of sufficient size to switch out the switched device • Repeat step 1 immediately (with minimum delay)	

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

Demonstration of Slope Characteristic

The Electricity Storage Module 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 Electricity Storage 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), 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 Electricity Storage Module 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) and response capability in excess of 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) indicates typical responses from plant with no delay in response from the start of the frequency deviation. Practically there is a permissible deadband 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.

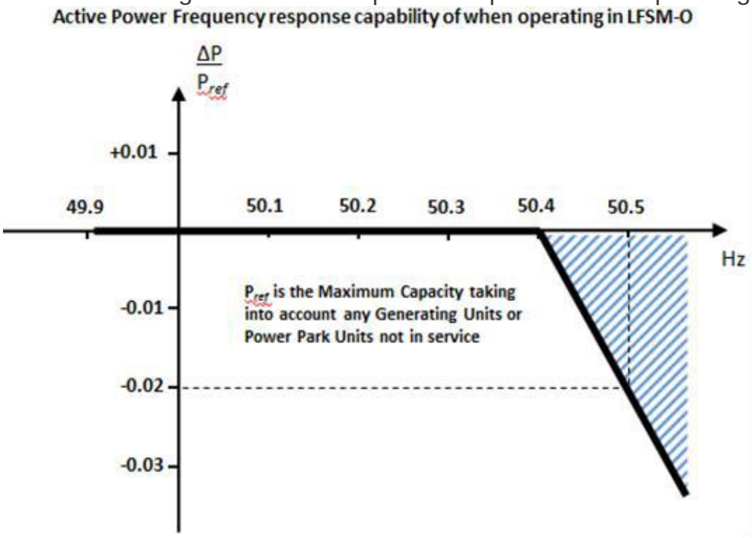
Modes of Frequency Control Operation

Balancing Code 3 (BC3) of the Grid Code defines operation in Limited Frequency Sensitive Mode and Frequency Sensitive Mode.

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 Electricity Storage Module 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 Electrical Storage 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 Electrical Storage Modules to have this capability. The Electricity Storage Module is expected to meet the 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 Electrical Storage Module is not required to provide any increase in active power output if frequency reduces below 50Hz but stays above 49.5Hz. It is only required to maintain active power output in accordance with ECC.6.3.3. However, when the system frequency falls below 49.5Hz the rate of change of Active Power output must be at a minimum rate of 2 percent of output per 0.1 Hz deviation (ie a droop of 10%) as shown in Figure ECC.6.3.7.2.2 below provided sufficient headroom is available. This is not an Ancillary Service, it is a European Connection Condition requirement for all Electricity Storage Modules to have this capability. The Electricity Storage Module is expected to meet the LFSM-U requirement in export mode only.

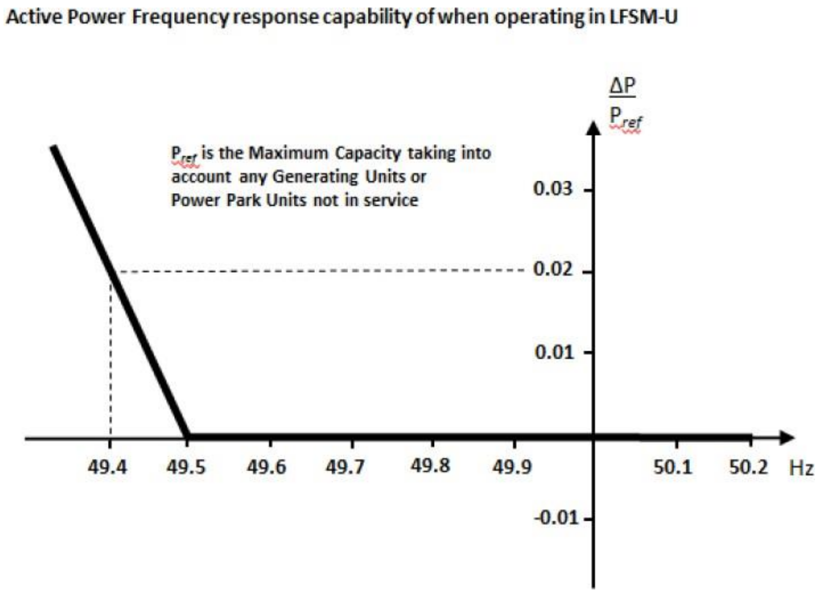


Figure C2 : Active power response when operating in LFSM-U export mode

For the import mode, the Electricity Storage Module should meet.

Either (1) Low Frequency Demand Disconnection LFDD) function as in OC.6.6.6. For example, for a battery storage module rated at 50MW, the storage module would be expected to disconnect 12.5 % of Registered Capacity for every 0.05 Hz drop in system frequency as shown below.

49.5Hz 6.25MW 12.5% of RC

49.45Hz 6.25MW 12.5% of RC

49.4Hz 6.25MW 12.5% of RC

49.35Hz 6.25MW 12.5% of RC

49.3Hz 6.25MW 12.5% of RC

49.25 Hz 6.25MW 12.5% of RC

49.2Hz 6.25MW 12.5% of RC

49.15Hz 6.25MW 12.5% of RC

All the demand expected to be tripped at 49.15Hz.

Or (2) De-load function as specified in ECC.6.3.7.2.3

a). The reduction in Active Power during an import mode of operation shall be continuously and linearly proportional, as far as is practicable, to the reduction in Frequency below 49.5 Hz. As much as possible of the proportional reduction in Active Power when the Electricity Storage Module is in an import mode of operation must result from the frequency control device (or speed governor) action and must be achieved within 10 seconds of the time of the Frequency decreases below 49.5 Hz. The Electricity Storage Module shall be capable of initiating a power Frequency response with an initial delay that is as short as possible. Delays that exceed 2 seconds shall be justified by the Generator providing technical evidence to The Company (ESO). A typical value of the Droop would be 0.6% where this does not result in control system instability or plant difficulties. In all cases the Droop shall be between 0.6% and 1.2% and shall be agreed with The Company (ESO).

b). Where the Electricity Storage Module is not capable of transitioning from an import level of operation to an export level of operation within 20 seconds of the System Frequency falling to 49.2Hz, then it shall immediately reduce its Active Power import to zero; and

c). If the Electricity Storage Module has not achieved at least a zero Active Power output when the System Frequency has reached 48.9Hz, it shall be instantaneously tripped.

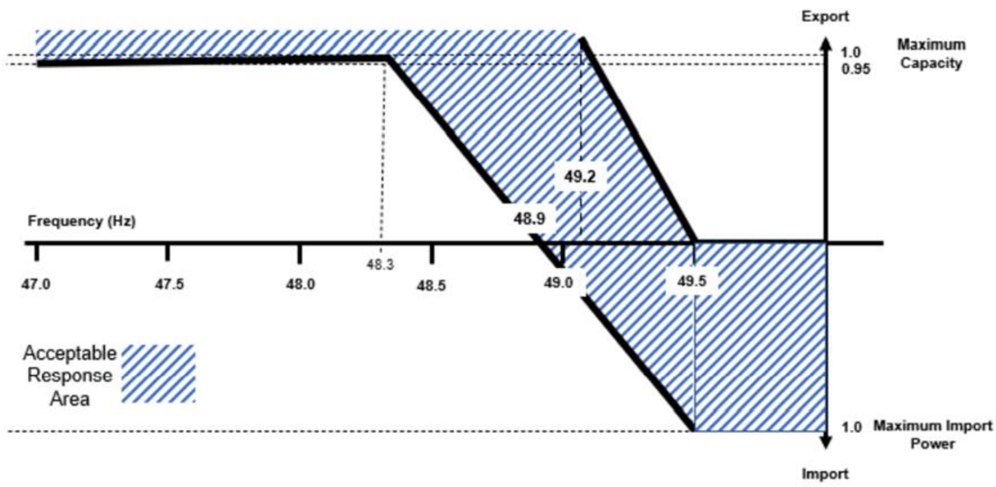


Figure C3: Active power response when operating in LFSM-U import mode

d) Where an Electricity Storage Module has been importing and has responded in accordance with the requirements of ECC.6.3.7.2.3.1, its performance, once the System Frequency starts to rise above the minimum reached, shall be in accordance with Figure C-4 in respect of the Active Power output and Active Power import. For example, FigureC-4, illustrates the four operating points W, X, Y and Z. If points W, X, Y and Z denotes the minimum frequency that the Total System reached during a particular low System Frequency event, as the System Frequency starts to rise, the Active Power output of the Electricity Storage Module should remain at a constant level (where the energy source has not been depleted) until 49.5Hz is reached as denoted by the dashed black lines. Once the System Frequency has risen above 49.5Hz the Electricity Storage Module is permitted to reduce Active Power output so long as it is operating within the shaded area above 49.5Hz shown in Figure C4 unless the Electricity Storage Module has insufficient capability in which case it shall operate at zero Active Power. Please also note, when operating between 48.9 to 49.5 Hz, if the low frequency event recurs the controller would follow the requirements specified in ECC.6.3.7.2.3

ECC.6.3.7.3.3 talks about conditions when operating in FSM (frequency sensitive mode) which is an instructed mode of operation. For Type C and Type D Power Generating Modules (including DC Connected Power Park Modules) without inertia, the delay in initial Active Power Frequency response shall not be greater than 1 second. Whereas, when operating in LFSM (limited frequency sensitive mode), the initial permissible delay in Active Power Frequency response shall not be greater than 2 seconds. Therefore, an Electricity Storage Module following a de-load function in import mode shall initiate a power frequency response with as fast as apossible and with minimum initial delay.

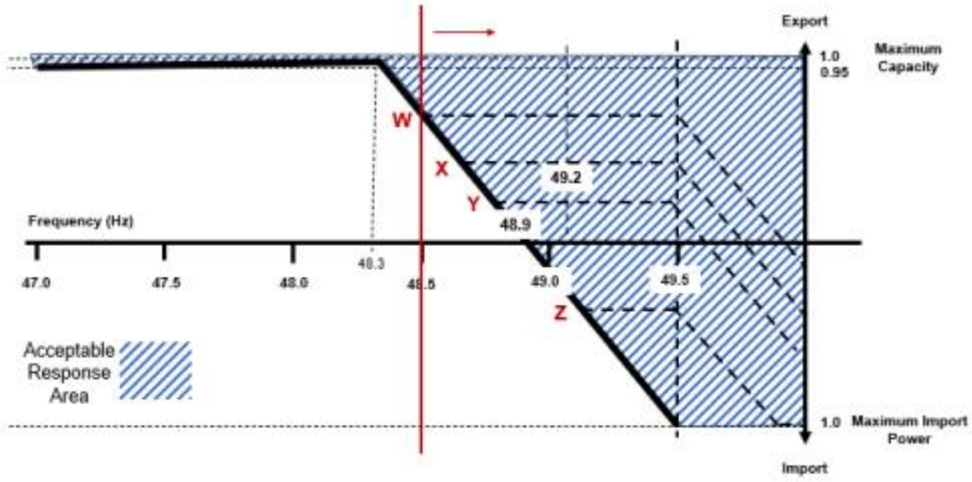


Figure C4: Active Power performance with increasing frequency

FSM Mode

Frequency Sensitive Mode is used when selected to provide frequency response services. In this mode the Electricity Storage Module must adjust the active power output in response to any frequency change according to the agreed droop characteristic (between 3-5%). For the purposes of the Mandatory Services Agreement the frequency response performance is measured in terms of the response achieved after a given duration. When system frequency exceeds 50.5Hz the requirements of Limited Frequency Sensitive Mode apply so that the Electricity Storage Module must further reduce output by a minimum of 2% of output for every 0.1Hz rise above 50.5Hz.

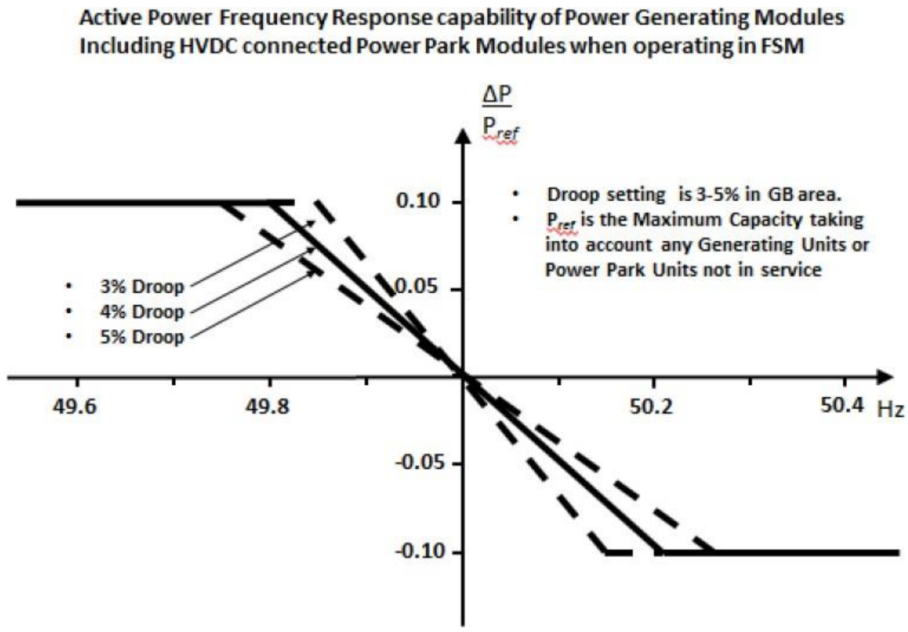


Figure C5 – Frequency Sensitive Mode

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

The ESO 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.

This function is tested by stepping the Target Frequency setpoint from the main control point as indicated in ECP.A.6.6.9.

Steady State Load Accuracy Requirements

Grid Code ECC.6.3.9 requires Electricity Storage Modules to be able to control output to a target with an accuracy specified as a standard deviation. To demonstrate compliance, the Electricity Storage Module 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.

In order to verify the plant behaviour, it is essential that the module is tested in normal operating modes. A frequency disturbance can be simulated by injecting the required frequency variation signals to the frequency reference/feedback summing junction. 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 ECP.A.6.6 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. If the Electrical Storage frequency control strategy incorporates independent local frequency control at each Electricity Storage Module then the Generator must identify and implement a method to simultaneously change all relevant frequency control set points or feedback signals to replicate a network frequency change.

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

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

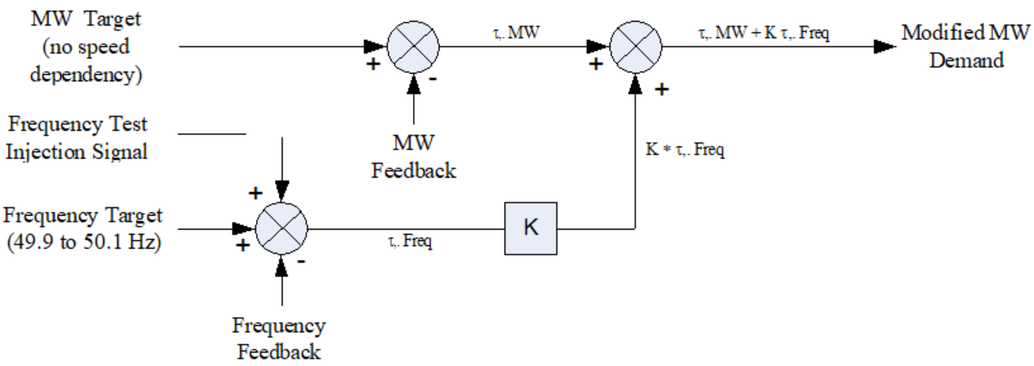


Figure C6 – Typical Frequency Test Injection Signal

Pre 70% Tests in Limited Frequency Sensitive Mode for Large Electricity Storage

Preliminary LFSM test applies to large Electricity Storage Modules with a registered capacity of 100MW or more. With large multi-module power stations, there may be a considerable delay before final frequency response testing can be carried out. To control the risk to the system during this period Grid Code ECP.A.6.3.1 requires two tests in Limited Frequency Sensitive mode to be completed before 70%, but at least 50% of the module has been commissioned.

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. Frequently this results in considerable lost time and additional expense for both parties. Consequently, this test has been drawn up and has been shown to help in preventing such situations arising.

Typical injection locations at the frequency controller are shown in Figure C6. 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 Electricity Storage Module or site contractor. A preliminary test is therefore required with details given in Grid Code ECP.A.6.6.4 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.

With the Electricity Storage Module running with all the modules in service (100%) and then deload to 80% between Minimum Regulating Level and Maximum Capacity to carry out the following frequency injections should be applied.

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 or longer until conditions stabilse • 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 stepchange • Hold until conditions stabilise • Remove the injection signal as a stepchange	Plant in FSM
I	• Inject +0.50Hz frequency rise as a stepchange • Hold until conditions stabilise • Remove the injection signal as a stepchange	Plant in FSM

The recorded results (e.g. Freq. injected, MW, Pavail, 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 number of module units in service should also be stated.

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.6.6 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).

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Grid Code ECP.A.6.6 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 the Electricity Storage Module 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 Electricity Storage Module 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.6.6 Figure 2 to establish the deloading capability as could occur under system islanding or system split conditions. Please note tests BC1 & BC2 are FSM whilst tests BC3 & BC4 are LFSM.

(d) Conduct test O as shown in ECP.A.6.6 Figure 2 to establish the Electricity Storage Module controller, and step response characteristics for Electricity Storage Module controller modelling purposes.

(e) Conduct test L as shown in ECP.A.6.6. Figure 2 and record plant responses

3. Response Tests at Loading Point MLP5 (90% MEL)

(a) Operate the plant at MLP5.

(b) Conduct tests 5-7 as shown in ECP.A.6.6 Figure 1 and record plant responses.

(c) Conduct test A as shown in ECP.A.6.6 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 (80% MEL)

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

(b) Conduct tests 8-14 as shown in ECP.A.6.6 Figure 1 and record plant responses.

(c) Conduct tests D - I as shown in ECP.A.6.6 Figure 2 to establish the Electricity Storage Module controller, and step response characteristics for Electricity Storage Module 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.6.6. 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.6.6 Figure 2 to demonstrate LFSM-O and LFSM-U capability.

(g) Conduct test N as shown in ECP.A.6.6. Figure 2 and record plant response

5. Response Tests at Load Point MLP3 (MRL+0.6 x (MEL – MRL))

(a) Operate the plant at MLP3.

(b) Conduct tests 15 to 17 as shown in ECP.A.6.6 Figure 1 and record plant responses.

6. Response Tests at Load Point MLP2 (MRL+0.3 x (MEL – MRL))

(c) Operate the plant at MLP2.

(d) Conduct tests 18 - 22 as shown in ECP.A.6.6 Figure 1 and record plant responses.

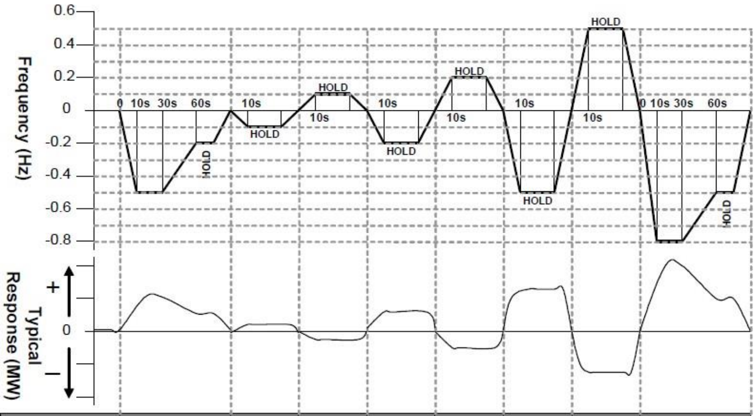
(e) Conduct tests P and Q as shown in ECP.A.6.6. Figure 2 and record plant responses.

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

(a) Operate the plant at MRL.

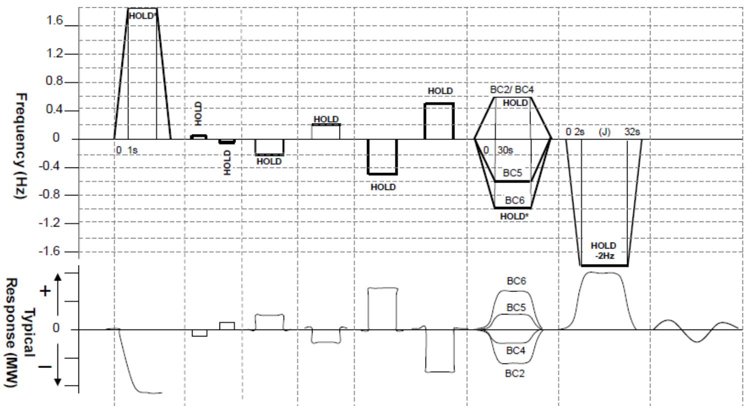
(b) Conduct tests 23 - 26 as shown in ECP.A.6.6 Figure 1 and record plant responses.

(c) Conduct test K as shown in ECP.A.6.6 Figure 2 to establish the step response characteristics for Electricity Storage controller modelling purposes.



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

ECP.A.6.6. Figure 1 – Frequency Response Capability FSM Ramp Response tests



Load Point	+2.0*	±0.02	-0.2	+0.2	-0.5	+0.5	+/-0.6 -1.0	-2.0	±0**
MLP6	BC1					O	BC2		L
MLP6 LFSM	BC3						BC4		
MLP5					A				
MLP4		D/E	F	G	H	I		J	M
MLP4 LFSM							BC5/6		N
MLP3									
MLP2					P	Q			
MLP1					K				

ECP.A.6.6. Figure 2 – Frequency Response Capability LFSM-O, LFSM-U, FSM Step Response tests

For the import mode, the BC5 and BC6 tests are not required. The Electricity Storage Module needs to demonstrate the de-load function through the testing requirement of ECP.A.6.6.10. For demonstrating LFDD, please refer to OC6.6.6

The Electricity Storage Module that operates in the LFSM **import** condition are expected to follow the steps to demonstrate the de-load function:

(i) Prior to the test, the Electricity Storage Module shall be operating at its Maximum Import Power with the Electricity Storage Module in Limited Frequency Sensitive Mode.

(ii) A test signal shall be applied which ramps the System Frequency from 50Hz to 49.0Hz at a rate of 2Hz/s. The System Frequency shall be held at 49.0Hz for 60s and the then ramped back to 50Hz in 10s as shown in Figure C7. When the test injection signal is held at 49.0Hz, the Active Power output of the Electricity Storage Module should achieve a steady state operating point in no more than 0.5 seconds, and this should be maintained whilst the test Frequency signal is held at 49.0Hz.

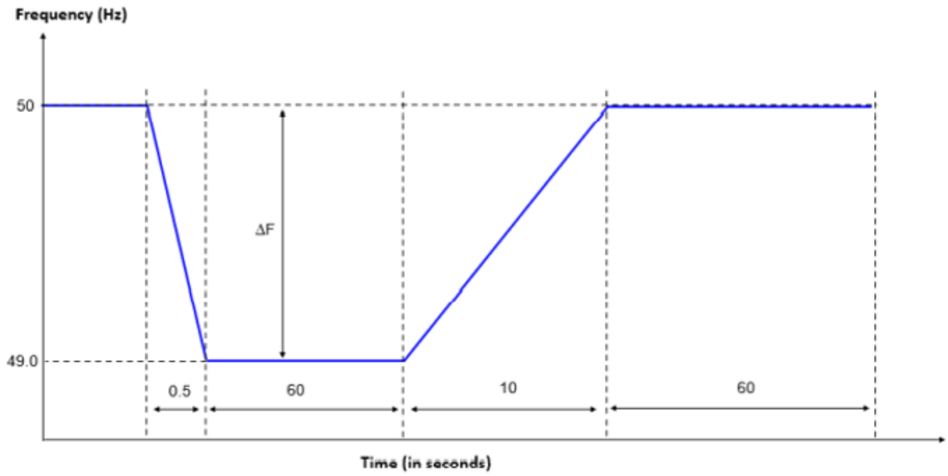


Figure C7 – Deload Function Test (a)

(iii) The above tests described (i) – (ii) above shall be repeated but the minimum test frequency applied shall be to 48.8Hz as shown in Figure C8.

(iv) The above tests shall be repeated when the Electricity Storage Module is operating at 40% of its Maximum Import Power.

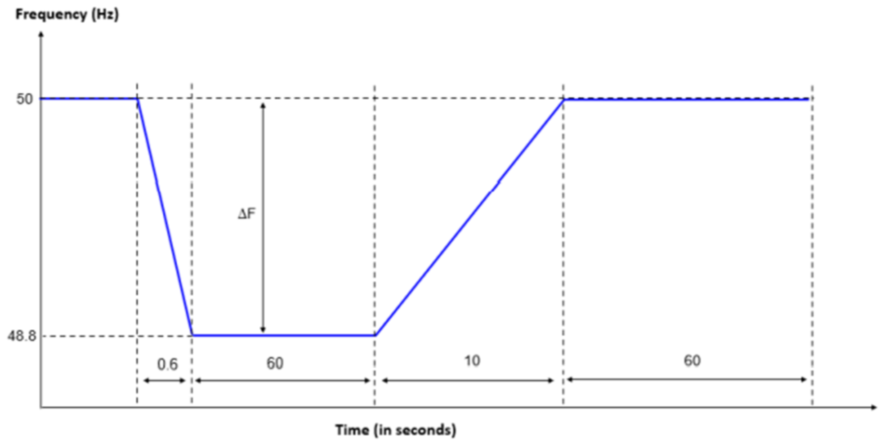
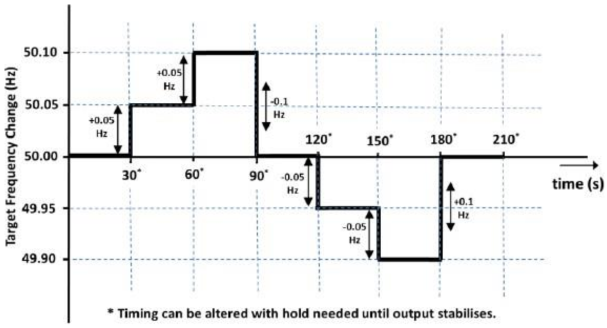


Figure C8 – Deload Function Test (b)

Control Requirements that may be witnessed

During attendance on site for witness testing of frequency response, ESO may request that the Generator alters the Target Frequency setpoint from the Generators Control Room as an indication of controllability. This may be combined with tests M in ECP.A.6.6. Figure 2 The following test procedure indicates the steps of target frequency required in ECP.A.6.6.9. =



ECP.A.6.6. 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 Power Parks with a point of connection to the Supergrid, the technique described below is still appropriate however the equivalent impedance (described above) is removed.

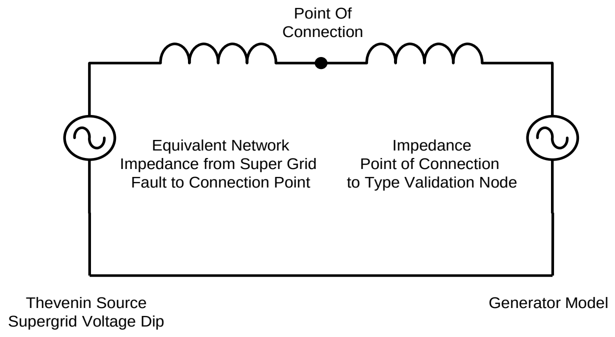
Positive Sequence Studies

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 Electricity Storage Module 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 Electrical Storage Module between the point of connection and the same node.

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

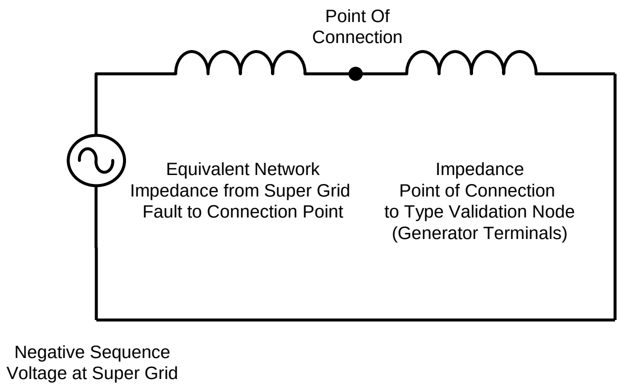


This simplified network can be implemented in a power system analysis package of the Developers choice using the voltage dips specified in Studies 3.1 & 3.2. The results at node ‘A’ are then compared to the type validation results to confirm ride through capability. The validity of the generator model’s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



Solving the load flow for the above network using a voltage source corresponding to the negative sequence magnitude at the Supergrid results in a negative sequence voltage estimate at the type validation node (‘A’). The results at node ‘A’ are then compared to the type validation results to confirm ride through capability. In the event that the type validation tests show that there is no single equivalent negative sequence impedance then the type validation will record a family of impedances equating to retained negative sequence voltages at the type validation node. The negative sequence studies will then be run iteratively, and the impedance value updated until reasonable convergence is obtained.

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 Electrical Storage 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 Electrical Storage 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 generator is required to provide the fault infeed from the Electricity Storage Module 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 Generator in calculating unbalanced short-circuit current contribution from the Electricity Storage Module at the entry point unless site specific values have been given. The Generator 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 Logsheet

Compliance Test Signal Schedules

Table 1 – Onshore Power Park Modules Voltage Control & Reactive Capability								
	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	Speed /Frequency #	Freq Injection #	Logic / Test Start #	Statcom or other Reactive Power #
	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16
1	Power Available			Voltage Setpoint				
2	State of Charge							
# Columns may be left blank but the column must still be included in the files								

Table 2 – Offshore Power Park Modules Voltage Control & Reactive Capability								
	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
1	Time (10ms)	Onshore Interface Point Active Power	Onshore Interface Point Reactive Power	Onshore Interface Point Voltage	Speed /Frequency #	Freq Injection #	Logic / Test Start #	Statcom or Other Reactive Power #
	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16
1	Power Available			Voltage Setpoint				
2	State of Charge							
# Columns may be left blank but the column must still be included in the files								

Table 3 - Power Park Modules Frequency Control								
	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
1	Time (100ms)	GEP Active Power	GEP Reactive Power #	GEP Connection Voltage #	Speed /Frequency	Freq Injection	Logic / Test Start	Statcom or Other Reactive Power #
	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16
1	Power Available							
2	State of Charge							
# Columns may be left blank but must still be included in the files								

Compliance Test Logsheet

Where test results are completed without any ESO presence but are relied upon as evidence of the compliance they should be accompanied by a logsheet. 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 eg Voltage Control.
- Ambient Conditions eg. Temperature.
- Controller settings, eg 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.
- Generators tap position or Grid Transformer tap position, as applicable.
- Number of Electrical Storage Units in service in each Module, if applicable.

Reactive Power Capability Tests

- Start time of test.
- Active Power.
- Reactive Power.
- Connection Voltage.
- Terminal Voltage if applicable.
- Generator unit transformer or grid transformer tap position as applicable.
- Number of Electrical Storage Units in service in each Module

Frequency Response Capability Tests

- Start time of test.
- Module Active Power.
- System Frequency.
- Droop setting of controller if applicable
- Number of Electrical Storage Units in service in each Module,

Appendix F: Contacting National Grid

There are a number of different departments within National Grid that will be involved with this connection. The initial point of contact for National Grid 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:

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

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

nationalgridESO