Guidance Note for Power Park Modules including Battery Storage

EU Code Users - Issue 1

April 2026

NESO
National Energy System Operator

Executive Summary

To obtain an Operational Notification, a Generator that owns and operates a Power Park Module (PPM), must demonstrate compliance with both the Grid Code and the Bilateral Connection Agreement (BCA). The Grid Code is a generic document outlining requirements that apply irrespective of local conditions. In contrast, the BCA is site-specific, established between NESO and the Generator, and as its name suggests defines specific parameters within the ranges set by the Grid Code and specific locational requirements. Consequently, the overall obligations on Generators comprise the combined requirements of the Grid Code and the BCA.

This Guidance Note has been developed by the National Energy System Operator (NESO) to support PPM developers, owners, and consultants by providing a clear and practical explanation of how to demonstrate compliance with the Grid Code and the associated BCA. It is intended to complement, not replace, the formal requirements of the Grid Code; in the event of any conflict, the Grid Code and BCA take precedence.

The guidance reflects experience from previous PPM compliance processes. Separate guidance applies to conventional synchronous generation, synchronous condensers, and HVDC converter equipment, which have different compliance requirements.

As defined by the Grid Code, the term PPM covers both onshore and offshore windfarms, solar and battery storage amongst other generation technologies driven by an intermittent power source or connected through power conversion technology. While this guidance note applies to all PPM types, some technical requirements differ between technologies under the generic banner of Power Park Modules although storage plant such as batteries under the definition of Electricity Storage Modules. Where this is the case, the specific technology-dependent requirements are provided in **Appendix C: Additional Technical Requirements for PPMs** and referenced from the main text as needed.

Embedded Small Power Stations should contact the relevant Distribution Network Operator (DNO) for guidance regarding compliance with the technical requirements of ENA G99. Embedded Medium Power Stations are subject (to some degree depending on whether they have a Bilateral Embedded Generation Agreement (BEGA) or Licence Exempt Embedded Medium Power Station (LEEMPS)) to fulfilling the Grid Code technical requirements and hence are advised to follow NESO Guidance Notes.

This Guidance Note is based on the Grid Code, Issue 6, Revision 37, dated 13th of April 2026. Definitions for the terminology used in this document can be found in the Grid Code. Where the Grid Code lacks clarity, this guidance reflects NESO's interpretation, industrial experience and understanding following due consideration and engagement with industry, while recognising that alternative valid interpretations may exist. NESO welcomes feedback and suggestions that support compliance while reducing the compliance effort. Feedback should be directed to the NESO Engineering Compliance team at (**box.ec.queries@neso.energy**).

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Version History:

Version	Date	Comment
Issue 1	April 2026	Complete revamp of the document. Document updated to merge BESS and PPM into single guidance note. Sections for BESS Augmentation introduced. Section for Staged connection introduced.

Disclaimer

This document has been prepared for guidance only and does not contain all the information needed to comply with the specific requirements of the Grid Code, or any other applicable industry code. Please note that whilst these Guidance Notes have been prepared with due care, National Energy System Operator 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. We recommend you seek your own professional advice.

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Abbreviations

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

Abbreviation	Description
AC	Alternating Current
AVC	Automatic Voltage Control
BC	Balancing Code
BCA	Bilateral Connection Agreement
BESS	Battery Energy Storage System
BMU	Balancing Market Unit
CC	Connection Conditions
CCGT	Combined Cycle Gas Turbine
CP	Compliance Processes
CT	Current Transformer
CUSC	Connection and Use of System Code
DC	Direct Current
DNO	Distribution Network Operator
DRC	Data Registration Code
EC	Engineering Compliance
ECC	European Connection Conditions
ECP	European Compliance Processes
EMT	Electro-Magnetic Transient
ENA	Energy Networks Association
EON	Energisation Operational Notification
ESM	Electricity Storage Module
FAT	Factory Acceptance Test
FFCI	Fast Fault Current Injection
FON	Final Operational Notification
FRT	Fault Ride Through
FSM	Frequency Sensitive Mode
GB	Great Britain
GEP	Grid Entry Point
HV	High Voltage
HVDC	High Voltage Direct Current
IBR	Inverter Based Resource
IET	Integral Equipment Test
ION	Interim Operational Notification
LFDD	Low Frequency Demand Disconnection
LFSM	Limited Frequency Sensitive Mode
LON	Limited Operational Notification

LV	Low Voltage
MEL	Maximum Export Limit
MLP	Module Load Point
MRL	Minimum Regulating Level
MSA	Mandatory Services Agreement
MSOL	Minimum Stable Operating Level
MV	Medium Voltage
NESO	National Energy System Operator
NGET	National Grid Electricity Transmission
OC	Operating Code
OFTO	Offshore Transmission Owner
OGEP	Offshore Grid Entry Point
ONCP	Operational Notification and Compliance Process
OTSDUW	Offshore Transmission System Development User Works
OTSUA	Offshore Transmission System User Assets
PC	Planning Code
PGM	Power Generating Module
PPC	Power Plant Controller
PPM	Power Park Module
PSS	Power System Stabiliser
RMS	Root Mean Square
SG	Synchronous Generator
TIP	Transmission Interface Point
TO	Transmission Owner
UDFS	User Data File Structure
USEP	User System Entry Point
VT	Voltage Transformer

1. Purpose, Scope and How to Use This Document

1.1 Purpose

The purpose of this guidance note is to support Users connecting Power Park Modules in understanding and meeting the technical, modelling, testing, and documentation requirements of the Grid Code and Bilateral Agreement. 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. Generators may, if they wish, suggest alternative tests or studies which they believe will demonstrate compliance in accordance with the requirements placed on them.

This document explains the technical requirements, simulation studies requirements, on-site compliance tests and data submissions that Users must fulfil before NESO can issue the relevant Operational Notifications. It provides detailed technical sections covering reactive capability, voltage control, fault ride-through (FRT) and frequency control.

1.2 Who Should Use This Guidance

This guidance is intended for:

- Developers, owners and operators of Power Stations comprising Power Park Modules which are either directly connected to the National Electricity Transmission System or form part of an Embedded Large Power Station.
- Engineering consultants supporting design, modelling or compliance work.
- Manufacturers who provide PPM equipment and models for compliance assessment.

1.3 Scope

This Guidance applies to various types of Power Park Modules including onshore and offshore PPMs and Electricity Storage Modules (ESMs)

1.4 Relevant Grid Code sections

This document should be read alongside:

- The European Connection Conditions (ECC).
- European Compliance Processes (ECP) and its relevant appendices (ECP.A.3) and (ECP.A.6).
- The Planning Code (PC).

1.5 Quick Navigation Guide

- Where do I find Voltage Control Technical requirements?
  4.2 Summary of Voltage Control Requirements
- Where do I find FRT/FFCI Technical requirements?
  4.3 Summary of FRT and FFCI Requirements
- Where do I find Frequency Response Compliance Tests requirements?
  B.4. Frequency Response Compliance Tests
- Where do I find Reactive Capability Compliance Tests?

B.1. Reactive Capability Compliance Tests

- What applies to Battery PPMs?
  C.2. Requirements for BESS:

- Where do I find simulation studies requirements?
  Appendix A: Summary of relevant ECP.A.3 Simulation Studies Requirements

2. Compliance Process

The process for Users 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 PPMs (ECP.A.6).

The European Compliance Processes cross reference with other sections of the Grid Code, namely the Planning Code (PC) and the European Connection Conditions (ECC). 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 most of this information is set out in the Data Registration Code (DRC). The ECCs set 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 compliance requirements of the simulations/tests which NESO requires to demonstrate compliance with the Grid Code.

For further details on the compliance process, please refer to the Guidance Notes for the compliance process on The Company website. Links can also be found in **Appendix I: Important Links**: which include the full compliance procedure. The document outlines the Operational Notification and Compliance Process (ONCP) managed by NESO for new generation connections. The ONCP incorporates the requirements set out in the European Compliance Processes section of the Grid Code, as well as the specific obligations defined in Bilateral Agreements. For historic legacy projects caught by the Grid Code Connection Conditions, the associated compliance requirements are defined in the Grid Code Compliance Processes rather than the European Compliance Processes.

2.1 EU and GB users

For existing connections (connected prior to 27 April 2019) and who have placed purchase contracts for their main plant and apparatus prior to 17 May 2018, the Generator will be deemed a GB User and the new requirements in the European Connection Conditions (ECCs) will not apply, although to be clear they would be caught by the requirements of the Grid Code Connection Conditions (CCs) and Compliance Processes (CPs). However, if an existing power station undertakes a Substantial Modification to its plant or apparatus new requirements will become applicable under the ECCs.

2.2 Plant Size

Under the EU Code, the technical requirements for a Power Generating Module (PGM) are based on its size and the connection point voltage. A Power Generating Module is defined in the Grid Code but, for the purposes of this document, the emphasis is placed on Power Park Modules. These are categorized as follows:

Table 1: Plant Categories under the EU Code

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 is classified as a Large, Medium or Small as defined in the Grid Code Glossary and Definitions. This could comprise 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 NESO.

2.3 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 public network. This is often the termination point in compact switchgear owned by a network licensee, or a short cable owned by the Generator.

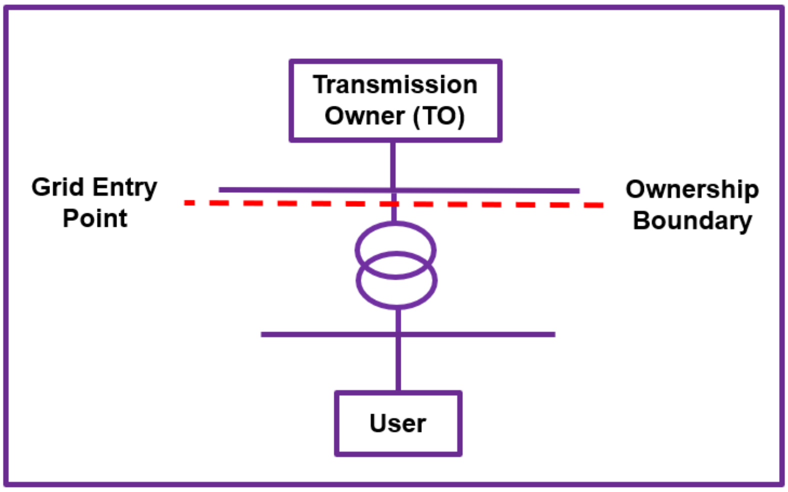


Figure 1: Point of Compliance.

In practical terms, if the cable has negligible impact on performance (including reactive capability), 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 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.

For offshore Power Park Modules, the control and signals for all compliance aspects should be available at the onshore (Interface) point (see Figure 2 below). For offshore Power Park Modules the real time signals for witnessing tests are measured at the onshore Interface Point as illustrated in the following diagram and mentioned in ECP.A.4.3.3 (iii).

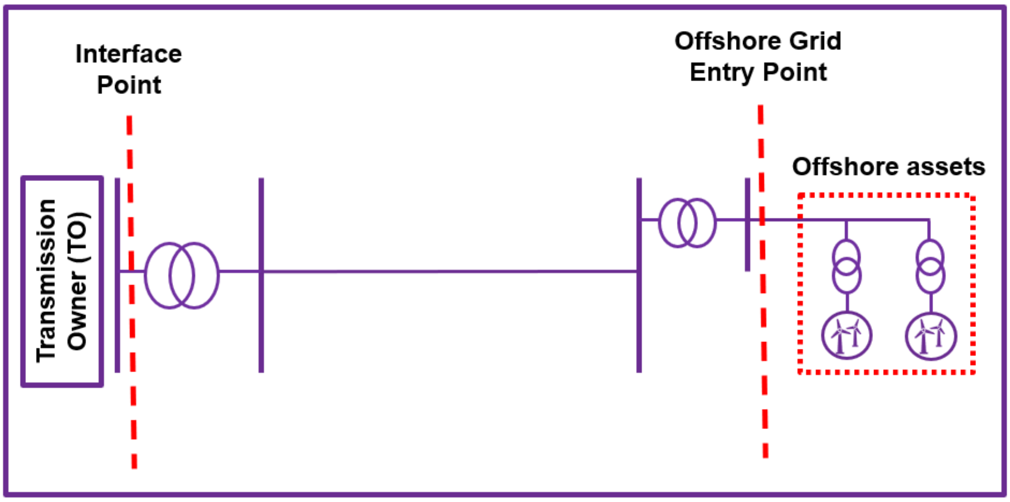


Figure 2: Point of Compliance for Offshore Modules.

Special requirements for Offshore PPMs are outlined under **Section C.1.** of this document.

2.4 Interim Operation

During the commissioning of PPMs, there may be a significant time gap between the commissioning of the first and last units within a module. To manage this, the Grid Code European Compliance Processes (ECP) outline two key capacity restrictions which are governed through the Interim Operational Notification (ION).

The first restriction limits operation such that both the PPM active power output and the number of commissioned power park units do not exceed 20% of the registered capacity and total number of units. According to clause ECP.A.6.2.1, the Generator must complete the basic voltage control tests (ECP.A.6.5.6(i) or (ii)) before more than 20% of the module units, or 50 MW (whichever is lower), are commissioned. These tests must be carried out while maintaining operation within the 20% limit, and the results must be submitted to NESO for approval before the restriction can be lifted.
The second restriction applies to PPMs with a registered capacity of 100 MW or greater. Under this restriction, **both the PPM active power output and the number of commissioned power park units are limited to a maximum of 70% of the registered capacity and total unit count**. After at least 50% of the module is online, the Generator must complete the Limited Frequency Sensitive tests (BC3 and BC4) in accordance with ECP.A.6.6.2. These tests are mandatory under ECP.A.6.3.1 and are required to enable progression beyond the 70% commissioning threshold.

2.5 Compliance Repeat Plan

Grid Code modification GC0141 introduced the requirement for users to restate compliance every 5 years from the issuance of a FON (ECP.8). The compliance repeat plan is required within 5 years of expiry of the FON. NESO will notify the User to confirm continued compliance. To do so, the User will be required to submit 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 provided 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, NESO will issue the User with an FON, and the User can continue operation as previously. 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, NESO 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.

For further details about the Compliance Repeat Plan, please refer to the Guidance notes published on The Company's website, links can also be found in **Appendix I: Important Links**:.

3. Modelling Requirements

To comply with the planning code requirements of the Grid Code, users are required to provide to NESO validated RMS and EMT model(s) which adequately represent the dynamic performance of their systems as demonstrated during the compliance process, its primary purpose is to ensure the models supplied, provide a true and accurate representation of the plant as built. The Models must be submitted according to the following timelines:

- At least 3 months prior to date requested for issue of the Interim Operational Notification.
- At least 1 month prior to date of issue of a Limited Operational Notification for the Users Plant and Apparatus.

As the model review process is iterative and involves multiple teams across NESO, Users are strongly encouraged to submit their models as early as possible once the simulation studies have been approved and accepted. Early submission helps facilitate timely engagement and can reduce delays during the compliance stage. The models shall be submitted accompanied by all the relevant documentation required by the Grid Code for NESO to be able to assess the model(s) performance. The documentation includes:

- The model(s) user guide.
- The model(s) supporting documentation.
- The model(s) performance and validation report.

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 the Guidance Notes on Modelling Requirements and EMT models published on the Company website. Links can also be found in **Appendix I: Important Links:.**

3.1 Software Quality Assurance

The User must adopt and be able to demonstrate the use of recognised software quality assurance techniques to manage control system design and parameter changes implemented during the commissioning process. This is to demonstrate that the control system undergoing testing remains aligned with the models and simulations submitted for approval by the User at the ION stage.

As a minimum, design review and version control techniques should be employed to maintain the integrity and design intent of any software that is undergoing commissioning.

A test plan should be submitted to The Company for information, prior to site commissioning activities taking place.

The Company also reserves the right to attend selected site commissioning tests to witness the effective use of the quality plan and associated procedures, as deemed appropriate.

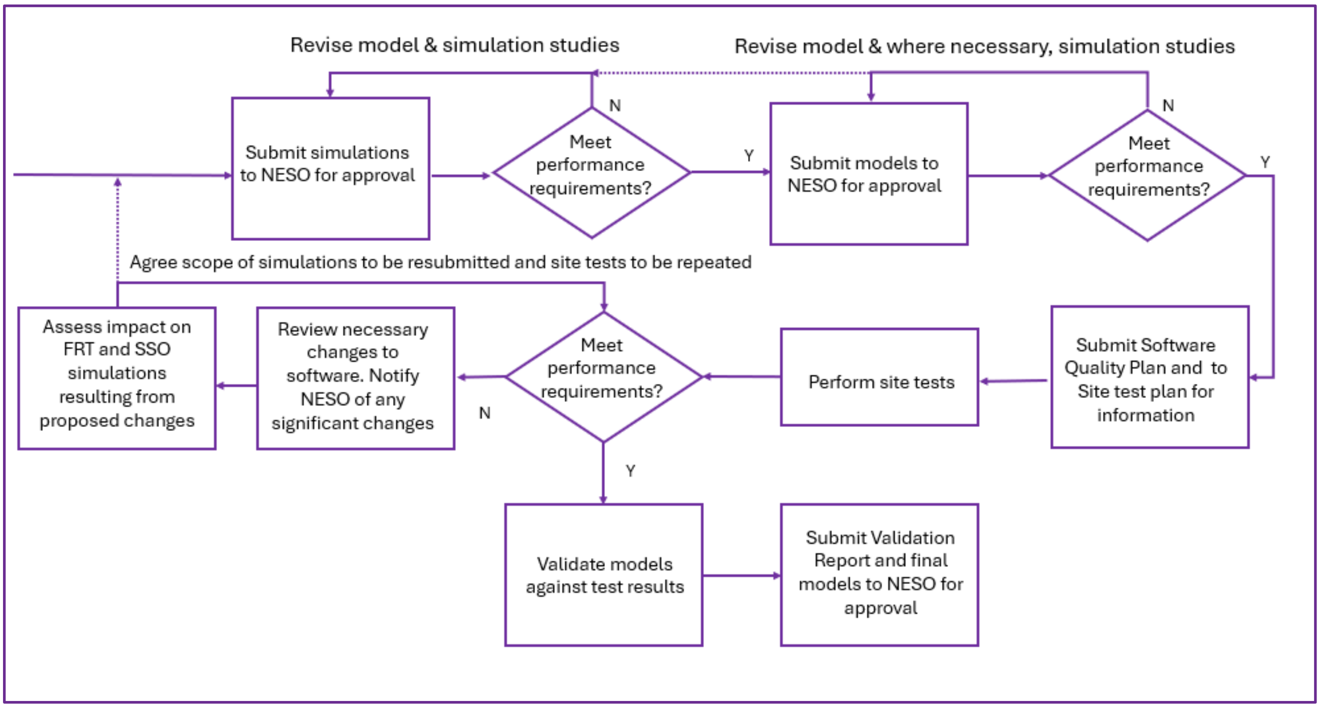


Figure 3: Typical Software Management Process.

4. Summary of Relevant Grid Code ECC Requirements

This section sets out the technical performance requirements that all Power Park Modules must meet in accordance with the ECC section of the Grid Code. It defines the minimum functional capabilities, operating behaviours and control system expectations necessary to ensure safe, reliable and coordinated operation of the plant on the GB Transmission System. The requirements apply across all operating modes and must be demonstrated through validated models, simulation studies and on-site testing.

The Grid Code is continually reviewed by NESO 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 this is to prevent the need to retrofit older plant with new equipment.

4.1 Summary of Reactive Capability Requirements

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

In summary, the first part of the requirement is for the PPM 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 PPM 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).

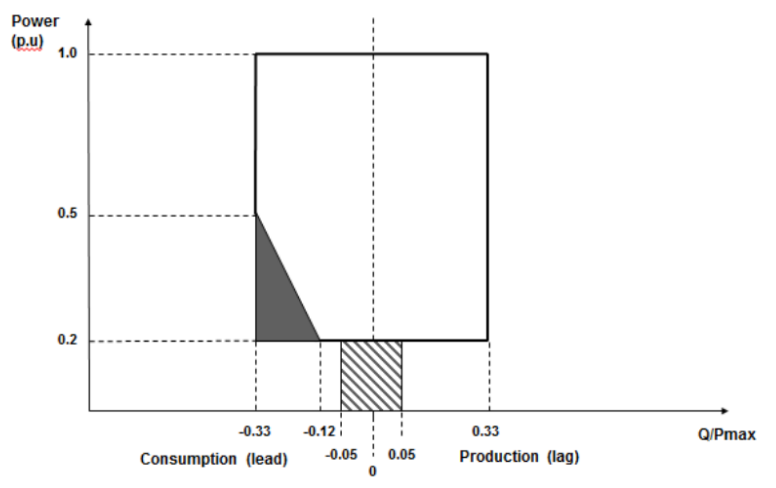


Figure ECC.6.3.2.4(c)

Figure 4: The reactive power capability at the connection point

Below 20% real power output, the PPM 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. and Figure ECC.6.3.2.4(a) requires 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 PPM developer does not have control of a transformer tap-changer to control voltages within the 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%) plant should deliver the maximum (lagging or leading respectively) reactive power possible, whilst remaining within its design limits.

For Electricity Storage Modules, the Grid Code requires compliance in both export and import mode of operation.

Contractual Opportunities Relating to Reactive Services

Developers wishing to provide additional Reactive Power services in excess of the minimum Reactive Power requirements, are encouraged to engage with the compliance engineer early in the compliance process.

4.2 Summary of Voltage Control Requirements

The generic requirements for voltage control are set out in the Grid Code European Connection Conditions ECC.6.3.8 and ECC.A.7 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.

For Electricity Storage Modules, the Grid Code requires compliance in both export and import modes of operation.

The Grid Code ECC Appendix 7 and ECC.A.7.2.3.1 sets out a number of criteria for acceptable steady-state and transient voltage response as summarised below:

- ECC.A.7.2.2.2 The voltage setpoint should be adjustable over a range of ±5% of nominal with a resolution of 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(i): The reactive power output response of the PPM shall commence within 0.2 seconds of the application of the step.
- ECC.A.7.2.3.1(ii): The speed of response to a step change should be sufficient to deliver 90% of the reactive capability within:
  - 1 second, if transition is from zero to max lead or lag.
  - 2 seconds, if transition is from max lead to max lag or vice versa

- ECC.A.7.2.3.1(iv): 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.7.2.3.1(iii): The magnitude of the Reactive Power response produced within 1 second shall vary linearly in proportion to the magnitude of the step change.
- 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 PPM 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.
- The Figure below illustrates responses that would be considered as meeting the Grid Code.

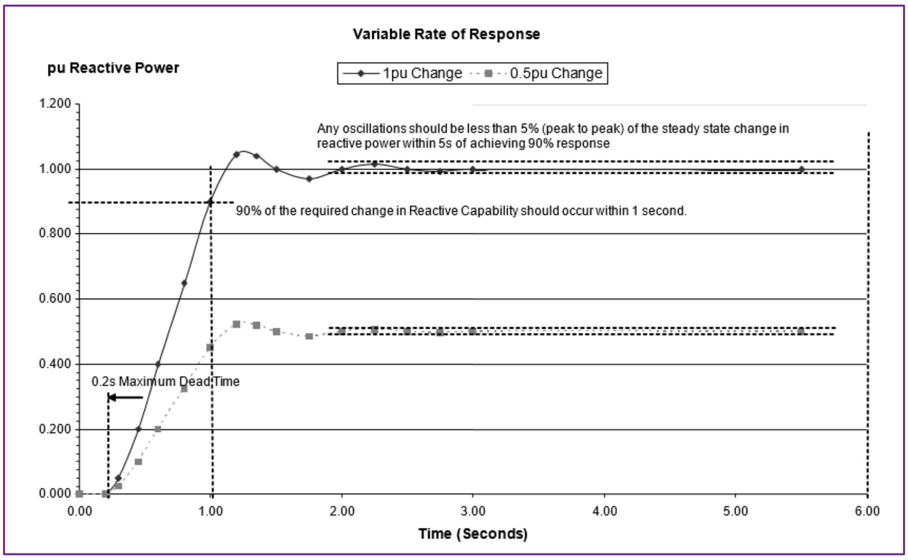


Figure 5: Example of Acceptable Transient Responses

Figure 5 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 the 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.

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.

The Generator must provide NESO with a transfer block diagram illustrating the PPM 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 NESO to review the suitability of the proposed test programme to demonstrate compliance with the Grid Code.

Demonstration of Slope Characteristic:

The PPM 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.

Delivery of Reactive Capability Beyond ±5% Voltage

The Grid Code requires Power Park Modules to have a Reactive Capability equivalent to 0.95 power factor usually at the Grid Entry Point or User System Entry Point if Embedded. 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 PPM 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 acknowledging that the volume of reactive power injected or absorbed from the Power Park Module can be curtailed where the system voltage is outside the nominal connection point voltage of ±5 %. That said, where the plant is operating outside of these voltage limits, the plant should be able to inject or absorb as much reactive power as possible without exceeding the rating of the plant.

4.3 Summary of FRT and FFCI Requirements

This section outlines the fault ride-through and fast fault current injection (FFCI) requirements for PPMs, as specified in section ECC.6.3.15 of the Grid Code.

To demonstrate compliance, the PPM developer is required to submit time-series simulation study results in the form of a report, as described in ECP.A.3.5. It is recommended that fault ride-through studies be conducted using electromagnetic transient (EMT) models.

For Electricity Storage Modules, the Grid Code requires compliance in both export and import modes of operation.

The Grid Code fault ride-through requirements apply to all fault scenarios occurring at the Grid Entry Point (GEP) or User System Entry Point (faults up to 140ms in duration) and at the Super-grid connection point (faults in excess of 140ms). These requirements vary depending on the fault type and the voltage profile, including fault duration and retained voltage levels.

For clarity, these requirements are categorised into two fault modes:

- **Short duration Faults lasting 140ms:** covered by ECC.6.3.15.1 to ECC.6.3.15.8, addresses transmission system faults lasting 140ms
- **Super Grid voltage Dips (faults in excess of 140ms):** detailed in ECC.6.3.15.9, applies to the period following fault clearance where voltage remains reduced.

Short duration faults up to 140msec:

Short duration faults refer to the initial 140 milliseconds of fault conditions, including three-phase, phase-to-phase, two-phase-to-earth, or single-phase-to-earth faults.

During this period, the PPM is required to remain transiently stable and connected to the system for any balanced or unbalanced fault, provided that the voltage at the Grid Entry Point or User System Entry Point remains at or above the heavy black line defined in sections ECC.6.3.15.2 through ECC.6.3.15.7.

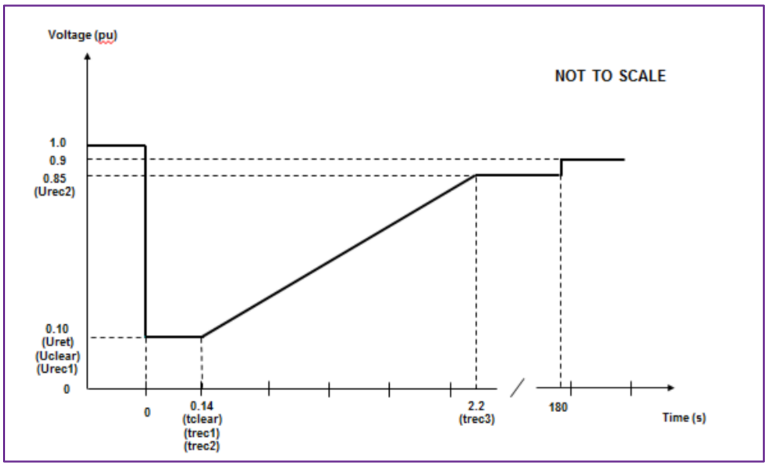


Figure 6: Voltage against time curve applicable to PPM connected below 110kV

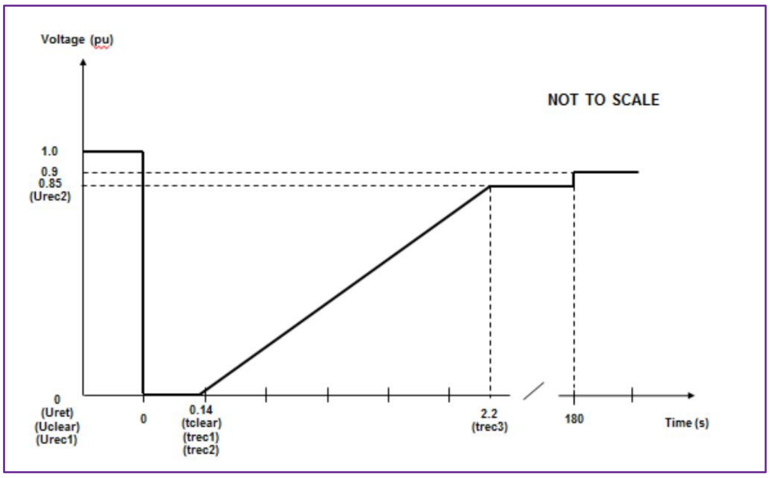


Figure 7: Voltage against time curve applicable to PPM connected at or above 110kV

The PPM must be capable of meeting these requirements while operating at Rated MW output and at its maximum leading Power Factor, as outlined in ECC.6.3.15.8. It should also deliver the maximum possible reactive current without exceeding its transient rating limits.

As specified in ECC.6.3.15.8(vii), within 0.5 seconds following fault clearance and restoration of voltage at the Grid Entry Point or User System Entry Point to 90% of nominal or higher, the PPM must restore its active power output to at least 90% of the level available immediately prior to the fault.

It is anticipated that the control system response during this period may exhibit underdamped behaviour. This is acceptable, provided that any resulting oscillations decay within a suitably short timeframe and that the average active power delivered during the oscillation period aligns with the levels required in the absence of such oscillations.

While voltage recovery typically begins upon fault clearance (within 140 milliseconds), it may not necessarily reach 90% of nominal voltage within that timeframe, as illustrated in the Appendix of the European Connection Conditions (ECC.A.4A.2). If the Super-grid voltage has not recovered to at least 90% within 140 milliseconds, the remaining duration of the fault may be treated as a period of balanced retained voltage, during which the requirements for faults in excess of 140ms will apply.

Additionally, Grid Code modification GC0141 introduces a requirement for the PPM to remain connected and stable for up to 30 minutes following a fault ride-through event.

Super Grid Voltage Dips – fault period longer than 140msec

Supergrid Voltage Dips refers to a period of balanced voltage depression resulting from power system events caused by remote faults (e.g. a remote stuck circuit breaker), or the period following the clearance of Super-grid faults during which voltage remains reduced.

Clause ECC.6.3.15.9.2.1(b) outlines the requirements applicable to Type C and Type D Power Park Modules that are subject to Super-grid voltage dips on the Onshore Transmission System lasting longer than 140 milliseconds.

In addition to the provisions set out in ECC.6.3.15.5, ECC.6.3.15.6, and ECC.6.3.15.8 (as applicable), each PPM, and/or any constituent unit, must remain transiently stable and connected to the system without tripping during balanced Super-grid voltage dips of the specified durations, as illustrated on or above the heavy black line in Figure ECC.6.3.15.9(b).

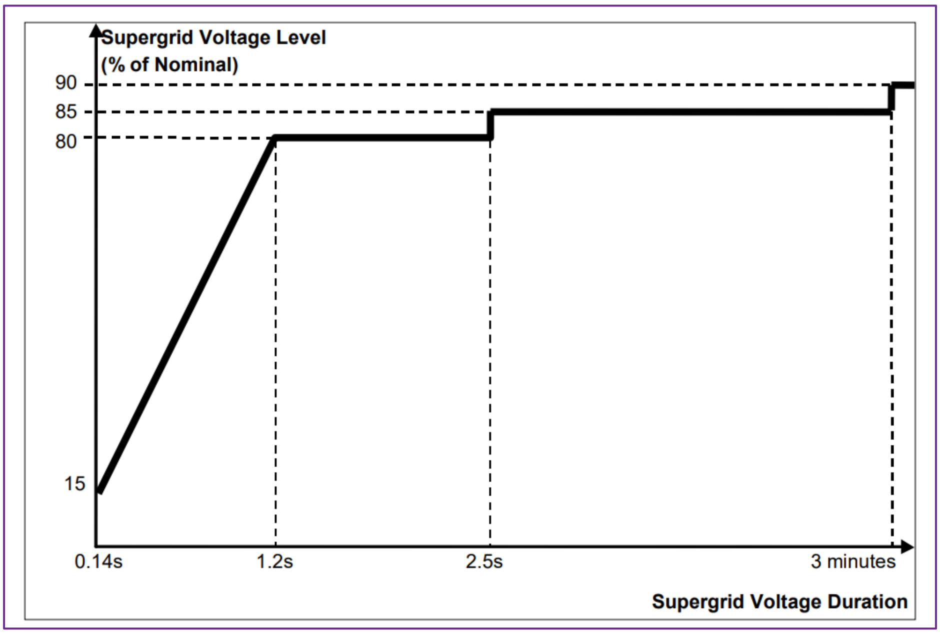


Figure 8: Voltage against time curve for longer duration faults

The PPM must maintain active power output, at least, in proportion to the retained balanced Super-grid voltage and deliver the maximum possible reactive current, without exceeding the transient rating limits of the PPM or any of its constituent components.

Each PPM and/or its constituent units must comply with the requirements set out in ECC.6.3.16.

Following a Super-grid voltage dip on the Onshore Transmission System, and within one second of voltage recovery to 0.9 per unit at the Onshore Grid Entry Point or User System Entry Point, the PPM is required to restore its active power output to at least 90% of the pre-fault level.

Appropriately damped active power oscillations are acceptable, provided that the total energy delivered during the oscillation period is no less than 90% of the expected value. The maximum duration for which Mode B requirements apply can be determined by identifying the lowest voltage occurring after the initial 140 milliseconds and referencing its intersection with the profile shown in Figure ECC.6.3.15.9(b).

Additionally, GC0141 introduces a requirement for the PPM to remain connected and stable for up to 30 minutes following a fault ride-through event.

Fast Fault Current Injection:

This requirement applies to Type B, Type C, and Type D PPMs. The principles and detailed provisions are outlined in section ECC.6.3.16 of the Grid Code. Simulation studies will be used to demonstrate compliance with the Fault Ride-Through and Fast Fault Current Injection (FFCI) requirements.

Specifically, ECC.6.3.16.1.2 states that for any balanced fault resulting in the positive phase sequence voltage falling below the thresholds defined in ECC.6.1.4 at the Grid Entry Point or User System Entry Point, each applicable Power Park Module, Power Park Unit, or HVDC Equipment must inject reactive current at levels, as a minimum, above the heavy black line illustrated in Figure ECC.6.3.16(a).

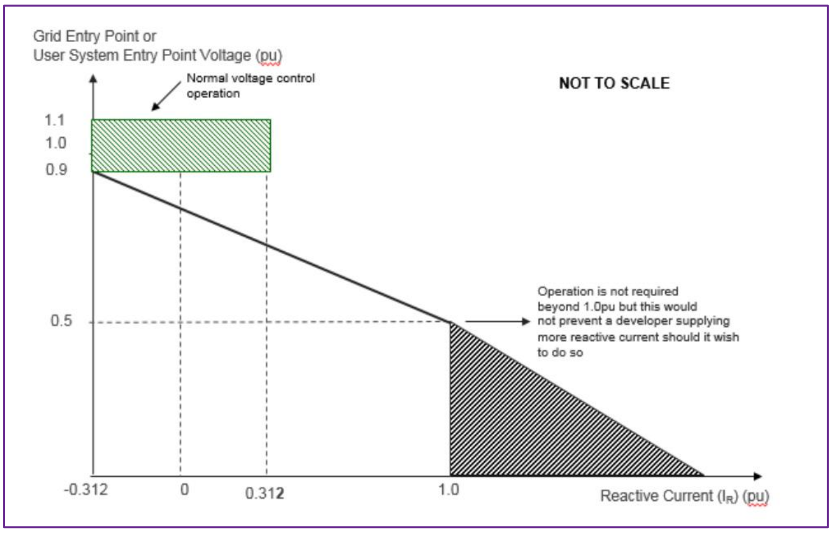


Figure 9: FFCI requirements.

Key notes about FFCI:

Section ECC.6.3.16.1.3 and Figure ECC.6.3.16(a) define the reactive current requirements under fault conditions. Specifically, the reactive current supplied must:

a. Be dependent on the pre-fault operating condition and the retained voltage at the Grid Entry Point or User System Entry Point.

b. Not fall below the pre-fault reactive current level.

c. As a minimum, increase proportionally with the fall in retained voltage each time the voltage at the Grid Entry Point or User System Entry Point falls below 0.9pu, while ensuring the overall rating of the PPM is not exceeded.

d. Remain above the shaded regions illustrated in Figures ECC.6.3.16(b) and ECC.6.3.16(c), which outline the expected reactive current injection profile over time. Fast Fault Current Injection (FFCI) should commence within 20 milliseconds and achieve at least 65% of the reactive current change within 60 milliseconds.

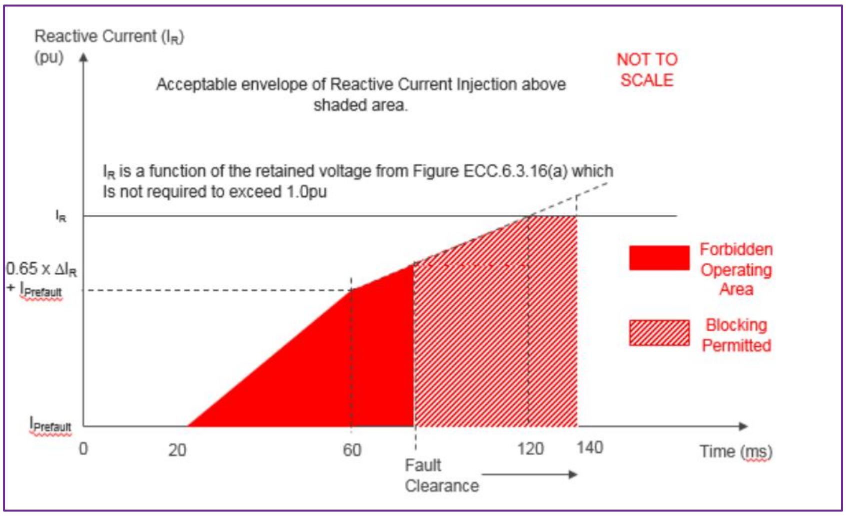


Figure 10: The expected reactive current injection profile over time

To demonstrate compliance with ECC.6.3.16, the PPM or HVDC System Owner is required to submit time-series simulation study results in the form of a report, as described in ECP.A.3.5. It is recommended that these simulations be conducted using EMT software, in accordance with PC.A.5.4 and PC.A.9.

4.4 Summary of Frequency Response Requirements

The National Electricity Transmission System is an island network with no AC connections to mainland Europe. To manage the system frequency within the normal operating range NESO requires generating units and PPMs 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.

ECC.6.3.3.1.1 of the Grid Code specifies that the PPM 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.

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 deadband and NESO 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 response tests are provided in ECP.A.6.6 but additional guidance is provided in this Appendix including outline test procedures.

For Electricity Storage Modules, the Grid Code requires compliance in both export and import mode of operation.

Modes of Frequency Control Operation

Balancing Code 3 (BC3) of the Grid Code ECC.6.3.7 defines operation in Limited Frequency Sensitive Mode and Frequency Sensitive Mode.

Limited Frequency Sensitive Mode - Over frequency (LFSM – O) general requirements:

Limited Frequency Sensitive Mode is the default mode used when not instructed by NESO to provide Frequency Response Services, this is not an Ancillary Service; it is a European Connection Condition requirement for all PPMs which have this capability. Electricity Storage Modules (including BESS) are expected to meet the LFSM-O requirement in both export and import modes of operation.

- As outlined in section ECC.6.3.7.1, Each PGM shall be capable of reducing active power output in response to frequency rises above 50.4Hz and operating stably during LFSM-O operation.
- If plant is operating in (FSM) Frequency Sensitive Mode, the requirements of LFSM-O shall apply when the frequency exceeds 50.5Hz, so that the PPM must further reduce output by a minimum of 2% of output for every 0.1Hz rise above 50.5Hz.
- The rate of change of Active Power output must be at a minimum a rate of 2 percent of output per 0.1 Hz deviation of System Frequency above 50.4Hz (i.e. a Droop of 10%) [the Droop range = 2: 10%].
- The reduction in Active Power output must be continuously and linearly proportional to the excess of Frequency above 50.4 Hz and must be provided increasingly with time over the period specified below.
- As much as possible of the proportional reduction in Active Power output must be achieved within 10 seconds of the time of the Frequency increase above 50.4 Hz.
- The PPM shall be capable of initiating a power Frequency response with an initial delay that is as short as possible (maximum of 2 seconds).
- The LFSM-O response must be reduced when the Frequency falls again and returns to a value less than 50.4Hz. In this case, as much as possible of the increase in Active Power must be achieved within 10 seconds.

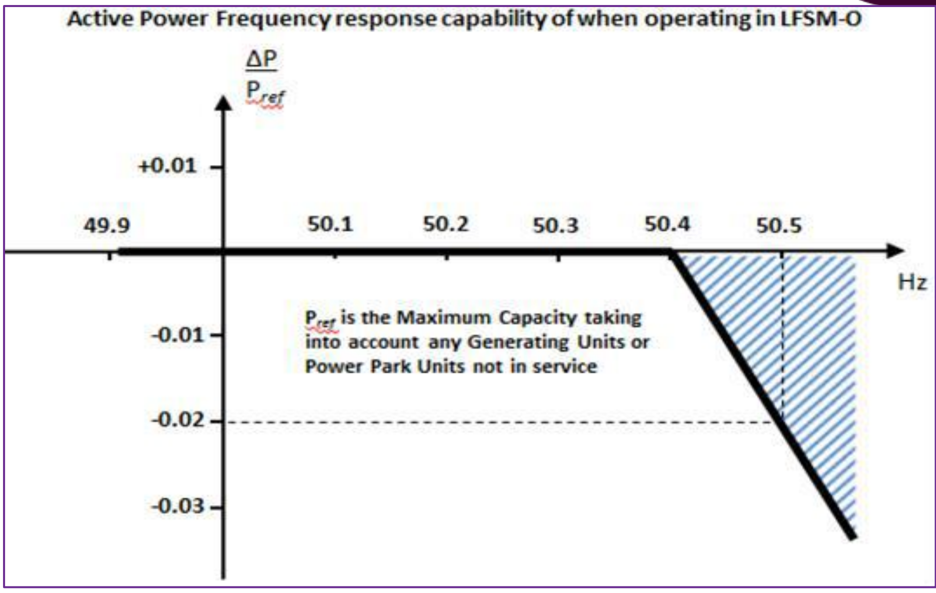


Figure 11: Active power response when operating in LFSM-O

Limited Frequency Sensitive Mode – underfrequency (LFSM-U) general requirements:

Limited Frequency Sensitive Mode is not an Ancillary Service; it is a European Connection Condition requirement for all PPMs to have this capability. The PPM is expected to meet the LFSM-U requirement in an export mode only, although specific requirements apply to Electricity Storage Modules as provided for in ECC.6.3.7.2.3 and **Section C.2.** of this document.

- As described in clause ECC.6.3.7.2, Each Type C and Type D PPM shall be capable of increasing Active Power output in response to System Frequency when this falls below 49.5Hz.
- The rate of change of Active Power output must be at a minimum a rate of 2 percent of output per 0.1 Hz deviation of System Frequency below 49.5Hz (i.e. a Droop of less than 10%)
- As much as possible of the proportional increase in Active Power output must result from the Frequency control device (or speed governor) action and must be achieved for Frequencies below 49.5 Hz.
- The PGM shall be capable of initiating a power Frequency response with minimal delay (maximum of 2 seconds).

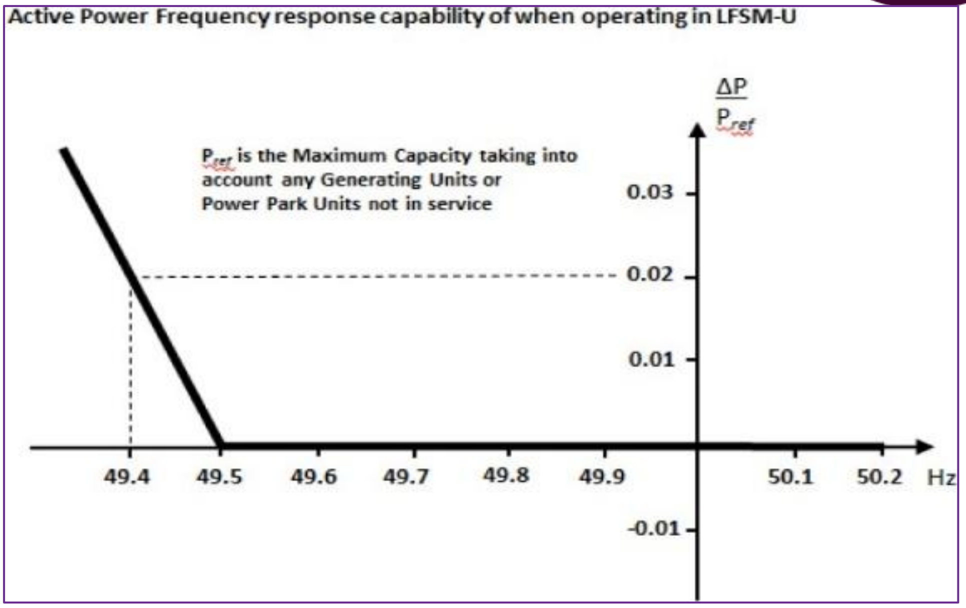


Figure 12: Active power response when operating in LFSM-U export mode

Frequency Sensitive Mode (FSM):

Frequency Sensitive Mode is used when selected to provide frequency response services. The requirements are for each Type C and Type D PPM to maintain stable active power response over the entire operating range.

- In this mode the PPM must adjust the active power output in response to any frequency change according to the agreed droop characteristic (between 3-5%) with a frequency control Insensitivity of less than ±0.015Hz or ±0.03%.

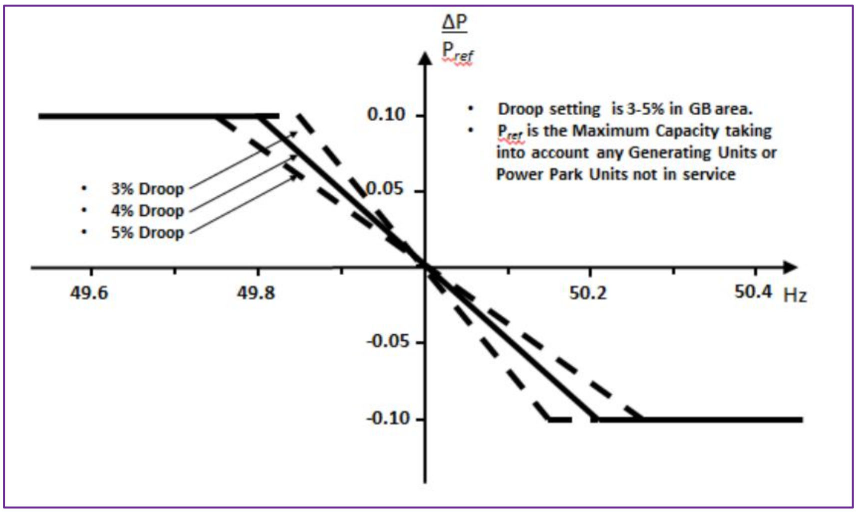


Figure 13: Frequency Sensitive Mode

- In the event of a Frequency step change, each Type C and Type D PGM shall be capable of activating full and stable Active Power Frequency response (without undue power oscillations).
- The initial activation of Active Power Primary Frequency response shall not be unduly delayed:
  - PGM with inertia, the delay shall not be greater than 2 seconds.
  - PGM without inertia, the delay shall not be greater than 1 second.

- The activation time (response time) should be no more than 10seconds.
- For the purposes of the Mandatory Services Agreement the frequency response performance is measured in terms of the response achieved after a given duration.
- In the case of underfrequency, the Active Power Frequency response is limited by the Maximum Capacity
- In the case of over-frequency, the Active Power Frequency response is limited by the Minimum Regulating Level.
- When system frequency exceeds 50.5Hz the requirements of Limited Frequency Sensitive Mode apply so that the PPM must further reduce output by a minimum of 2% of output for every 0.1Hz rise above 50.5Hz.

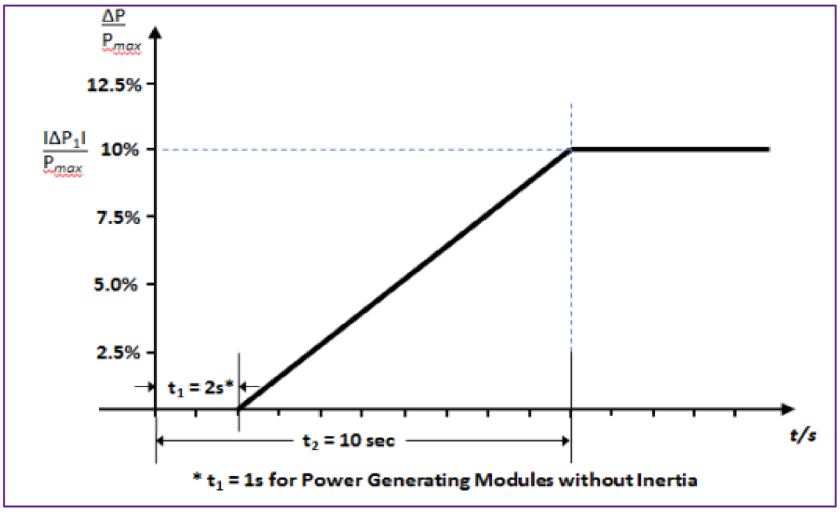


Figure 14: Frequency Sensitive Mode Timescales

Comparison between different frequency mode of operation:

The table below shows the comparison between different frequency modes of operation.

Mode	LFSM-O	LFSM-U	De-load	FSM
Applicability	Each PPM	Each Type C and Type D PPM	BESS Only	Each Type C and Type D PPM
Deadband	50.4Hz	49.5Hz	49.5Hz	49.985 – 50.015 Hz
Droop	2 - 10%	less than 10%	0.6 - 1.2%	3 – 5%
Delay	Less than 2secs	Less than 2secs	Less than 2secs	<2secs: PGM with inertia <1sec: PGM without inertia
Achieve time	within 10secs	within 10secs	within 10secs	within 10secs

Primary, Secondary, and High frequency responses:

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.

Section ECC.6.3.7.3.6 requires each Type C and Type D PGM to be capable of meeting the minimum Frequency response requirement profile subject to and in accordance with the provisions of Appendix A3 in the European Connection Conditions.

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). Although the minimum response is 10% of Maximum Capacity. a response capability of more than 10% is encouraged.

- **Primary Frequency Response (P):** The automatic increase in active power output from a PPM in response to a fall in system frequency. The response is delivered increasingly over the period from 0 to 10 seconds following the onset of the frequency fall, is fully available by the end of this period, and is sustained for at least a further 20 seconds.
- **Secondary Frequency Response (S):** The automatic increase in active power output from a PPM in response to a fall in system frequency. The response is fully available by 30 seconds from the onset of the frequency fall and is sustained for at least a further 30 minutes.

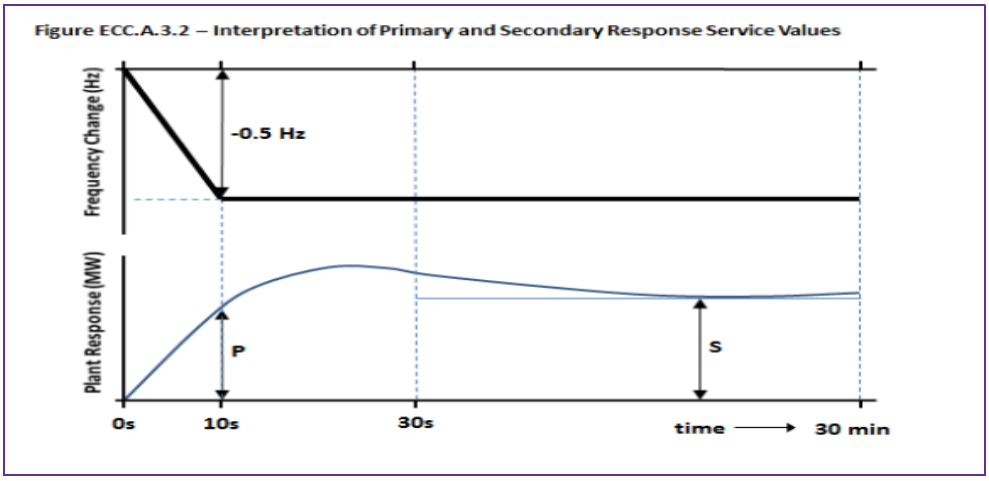


Figure 15: Primary and Secondary Frequency Responses

- **High Frequency Response (H):** The automatic reduction in active power output from a PPM in response to an increase in system frequency. The response is delivered progressively over the period from 0 to 10 seconds following the onset of the frequency increase, is fully achieved within this period, and is sustained thereafter with no lesser reduction.

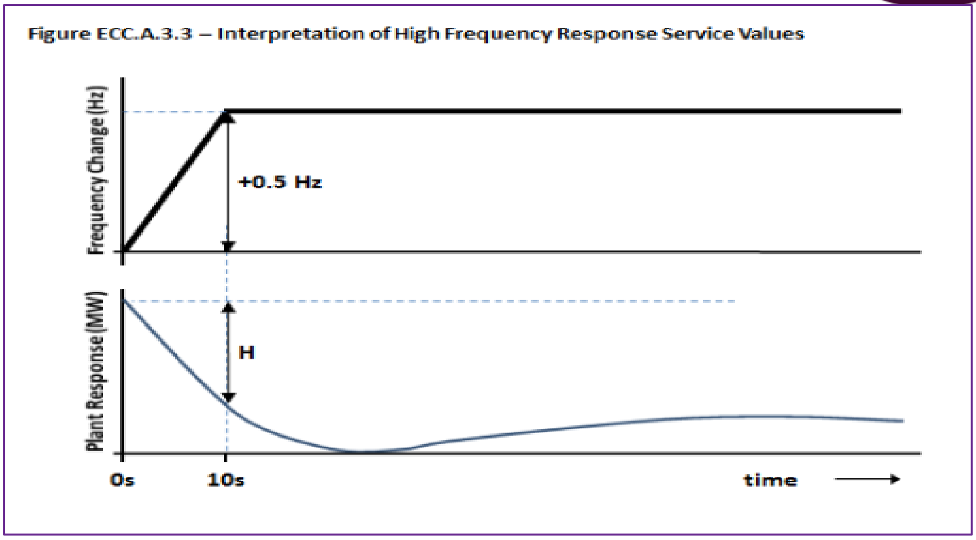


Figure 16: High Frequency Response

Steady State Load Accuracy Requirements

Grid Code clause ECC.6.3.9 requires a PPM to be capable of controlling its output to a specified target with an accuracy defined in terms of standard deviation. The standard deviation of the load error at steady-state load, assessed over a 30-minute period, must not exceed 2.5 per cent of the Maximum Capacity of a Type C or Type D PPM. With an intermittent power source this requirement applies when operating at power levels below the Maximum Export Level (MEL) which should reflect the availability of the power source.

To demonstrate compliance with this requirement, the PPM 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.

Appendices

Appendix A: Summary of relevant ECP.A.3 Simulation Studies Requirements

The simulation studies described in the European Compliance Processes (ECP.A.3) 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 NESO 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 supplied 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.

The simulations must be based on the validated models supplied to NESO in accordance with Grid Code Planning Code Appendix A section (PC.A.9) and be submitted before issuing an ION. Fault Ride Through studies are encouraged to be done using electromagnetic transient (EMT) models.

A.1. Reactive Capability Simulation Studies

The GC clause ECP.A.3.3.1(b) and ECP.A.3.3.1(c) outlines the required simulation studies for the PPMs to demonstrate compliance with the GC reactive capability requirements as follows:

- For PPMs where the Grid Entry Point or User System Entry Point Voltage is above 33kV, the Generator shall demonstrate the capability to meet ECC.6.3.2 by submission of a report containing load flow simulation study results to demonstrate operation at points A, B, E and F in accordance with Figure ECC.A.7.2.2(b) or Figure ECC.A.8.2.2(b).

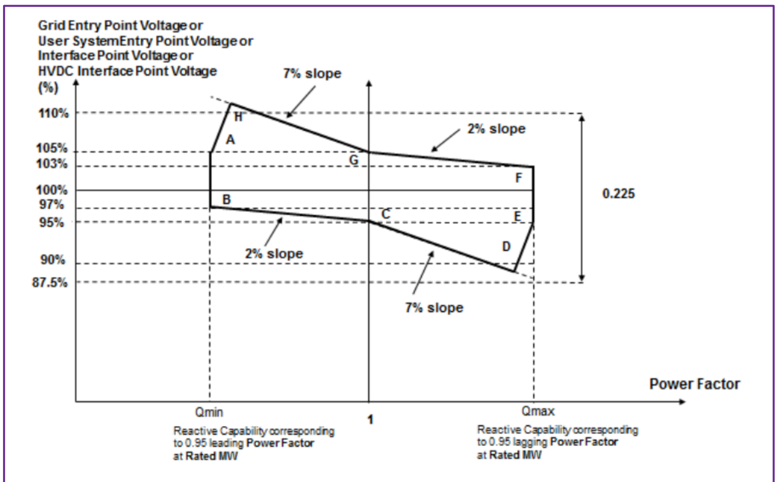


Figure ECC.A.7.2.2b

Figure 17: Reactive Requirements for modules with GEP voltage more than 33kV

- For PPMs with a Grid Entry Point or User System Entry Point Voltage at or below 33kV, a load flow simulation study results to demonstrate operation at points A, B, E and F in accordance with Figure ECC.A.7.2.2(c) or Figure ECC.A.8.2.2(b).

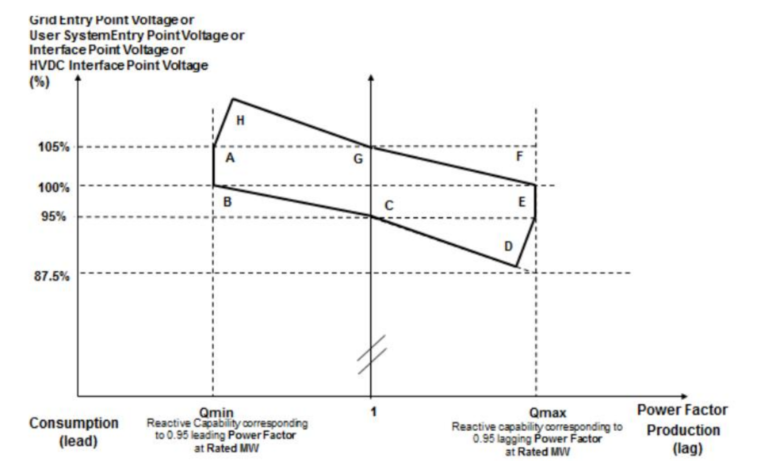


Figure ECC.A.7.2.2c

Figure 18: Reactive Requirements for modules with GEP voltage at or below 33kV

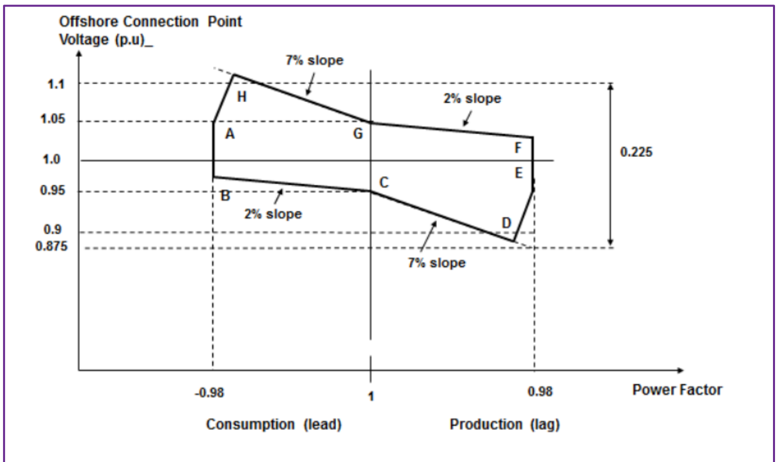


Figure ECC.A.8.2.2b

Figure 19: Reactive Requirements for Offshore modules

The studies should be run with the module operating at Maximum Capacity and at the Minimum Stable Operating Level.

A.2. Voltage Control Simulation Studies & Checklist:

Sections ECP.A.3.4.1 and ECP.A.3.7.4 outline how the required voltage control simulation studies apply to PPMs. The PPM developer shall provide a simulation study report to demonstrate the dynamic capability and control stability of the Module.

The PPM should also provide the voltage control simulation specified in ECP.A.3.7.4 to verify and validate the Voltage Controller model. This simulation will later be used during the compliance process to validate the accuracy of the model by comparing it against actual onsite test results.

While the preceding sections provide detailed explanations of the Voltage Control related GC requirements, NESO has outlined the Grid Code compliance requirements in the form of simplified checklists against which a submission shall be assessed. Please note the checklists provided here are for guidance purposes only, and Customers are encouraged to use it. It is, however, not a mandatory requirement for the Customers to fill in and submit these checklists during compliance. The checklist can be found in **Appendix H: Grid Code Compliance Simulations Checklists .**

A.3. Fault Ride Through Simulation Studies & Checklist:

Section ECP.A.3.5 outlines the required FRT & FFCI simulation studies applies to PPMs.

The required simulation studies for short-duration faults (up to 140 milliseconds) are outlined in ECP.A.3.5.1(i) & ECP.A.3.5.1(ii). The plant should be operating at rated MW output and at maximum leading power factor during all simulations, regardless of fault type or plant configuration. Simulations with short duration faults should be performed at the Grid Entry Point (GEP).

For GEP voltages below 110 kV, simulations must assume a retained voltage of 10% however, for GEP voltages above 110 kV, simulations must assume a retained voltage of 0%.

The required simulation studies for long-duration Three-phase faults or voltage dips lasting more than 140 milliseconds are outlined in ECP.A.3.5.1(iv). The plant shall be delivering rated MW output with zero reactive power across all plant types. Simulations with longer duration faults (longer than 140msec) should be performed at the nearest super-grid point.

Please note that FRT and FFCI studies should be carried out for all foreseeable running arrangements as required by ECP.A.3.5.3

While the preceding sections provide detailed explanations of the FRT/FFCI related GC requirements, NESO has outlined the Grid Code compliance requirements in the form of simplified checklists against which a submission shall be assessed. Please note the checklists provided here are for guidance purposes only, and Customers are encouraged to use it. It is, however, not a mandatory requirement for the Customers to fill in and submit these checklists during compliance. The checklist can be found in **Appendix I: Important Links: .**

A.4. Frequency Response Simulation Studies & Checklist:

The required simulation studies for frequency response are presented in Grid Code clauses ECP.A.3.6.1 - ECP.A.3.6.12, and ECP.A.3.7.2 and summarised in the checklist as explained below.

Load Rejection Simulations (FSM-O & LFSM-O):

The objective of the load rejection studies is to check the PPM's ability to modulate active power at high frequency, in accordance with ECC6.3.7.3.5(ii).

The methodology and procedures for conducting these simulations are detailed in sections ECP.A.3.6.2 through ECP.A.3.6.7.

Each simulation should include the PPM and an additional Synchronous Power Generating Module (G2), both connected to the overall System along with a combination of loads that would be tuned to achieve the required performance as illustrated below.

The additional Synchronous Power Generating Module (G2) must:

- ✓ Have an inertia constant of 3.5 MWs/MVA,
- ✓ Operate initially at rated power output with a unity power factor,

- ✓ Maintain constant mechanical power throughout the simulation, except when the PPM is at maximum import.

The following items should be carefully considered while performing load rejection simulations:

1. The PPM should be able to regulate the frequency of the power island, in line with ECC.6.3.7.3.5(ii).
2. In all cases, the PPM must respond in line with its declared droop and response time settings.
3. If transient frequency excursions above 52Hz occur, the PPM Owner must ensure that the duration of these excursions remains shorter than the activation threshold of any high-frequency protection systems applied to the PPM.
4. Only one droop setting is permitted per mode of operation. For example, if a 4% droop is selected for LFSM, it must be used across all LFSM simulations and tests except those involving the de-load function. Similarly, a 3% droop selected for FSM must be consistently applied across all FSM simulations and tests.
5. For simulations that include a frequency injection signal, the normal behaviour post event should be the plant returns to its pre-event operating point upon removing the injected frequency signal.
6. The simulation must monitor, at a minimum:
    a. PPM active power output
    b. Synchronous machine output power
    c. Load active power
    d. System frequency

At the start of the simulation, the PPM should be operating at its maximum export power level. The system should include the PPM and the fictitious synchronous generator supplying two loads, Load 1 and Load 2, with values tuned such that, under normal conditions, the arrangement is balanced in terms of generation and demand.

During the simulation, the PPM will be islanded from the total system, and Load 1 will be rejected, leaving the PPM and the synchronous generator to supply only Load 2. The value of Load 1 must be calculated according to the PPM's droop settings to ensure that its rejection causes the system frequency to rise, in accordance with ECC.6.3.7.3.5(ii). Achieving this frequency increase is a mandatory requirement.

In this scenario, and without any governor action from the synchronous generator, the PPM must regulate its active power output by reducing it in line with its declared droop settings, thereby demonstrating appropriate frequency response behaviour.

The current GC requirement forces the Non-Synchronous Generator to reduce the power output from Max. Capacity to the DMOL which is normally 0MW in the case of most IBR Generators. This can only be achieved if the User implements an aggressive droop setting for both LFSM and FSM modes. On contrary, the Grid Code ECC.6.3.7 offers much wider droop settings for different modes of frequency control operation as can be seen in following table.

Table 2: Acceptable Droop Ranges

Mode of operation	Droop range
LFSM-O	2-10%
LFSM-U	<10%
FSM	3-5%

Please refer to the following revised figure which has replaced the DMOL in the GC with the term 'Non-Synch G Output' which refers to **the PPM post-event output** which shall be calculated in accordance with the droop settings used for the PPM.

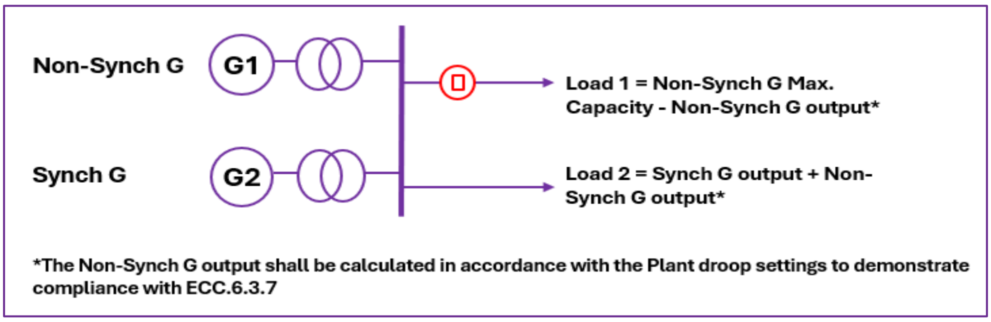


Figure 20: Load Rejection Arrangement

Please refer to the following table which demonstrates examples for different droop settings and corresponding Load 1 and Load 2 values for an PPM with Max. Capacity of 100MW, and a Synchronous Machine of 100MW.

Table 3: Examples for Load 1 and Load 2 Calculations

Mode	Droop	Max. Change in Frequency (Δf)	Req. Change in Active Power (ΔP)	Post-event PPM Output	Load 1	Load 2
LFSM	10%	2Hz	32MW	68MW	32MW	168MW
LFSM	4%	2Hz	80MW	20MW	80MW	120MW
FSM*	5%	2Hz	80MW	20MW	80MW	120MW
FSM*	4%	2Hz	100MW	0MW	100MW	100MW
*FSM deadband of +/-15mHz is not considered in the calculation for simplicity.						

ECP.A.3.6.8: Under-frequency Simulation – (LFSM-U):

To demonstrate LFSM-U capability, the PPM must submit a simulation study operating at 80% of Maximum Capacity. The study should show the PPM's response to a reduction in the measured system frequency—calculated in accordance with the declared droop settings—ramped over 10 seconds, resulting in an increase in active power output to maximum capacity. This should be followed by 60 seconds of steady-state operation with the frequency held at the reduced level (as illustrated in Figure 21 below). Then, the frequency should be ramped back up over 10 seconds, causing the Active Power output to return to its original level, followed by at least 60 seconds of steady output.

The normal behaviour post event should be the plant returns to its pre-event operating point upon removal of the injected frequency signal.

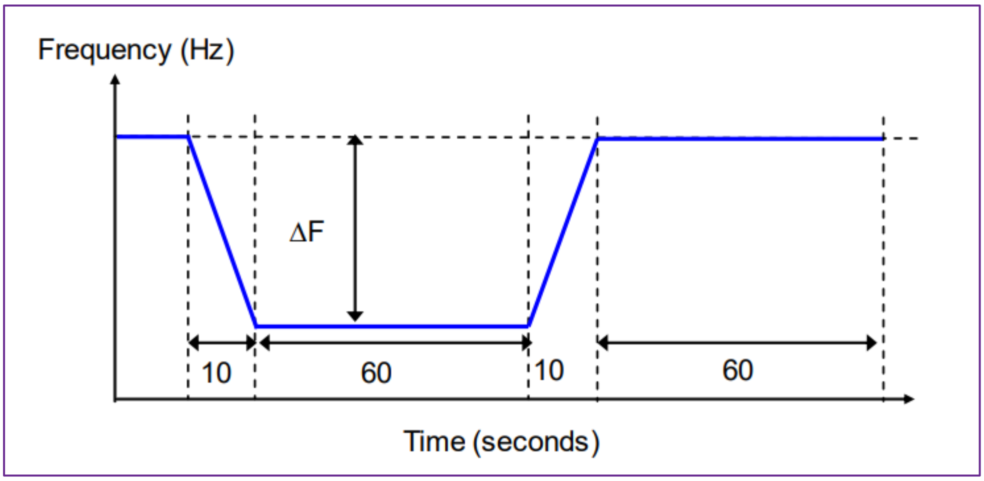


Figure 21: LFSM-U simulation ECP.A.3.6.8

ECP.A.3.7.2: Model Validation Simulations:

To demonstrate the performance of the frequency control system—whether implemented via a governor, load controller, or plant model—the PPM shall submit a simulation study illustrating its response while operating at 80% of maximum capacity.

The simulation event shall replicate a ramped reduction in measured system frequency by 0.5 Hz over 10 seconds, followed by a 20-second steady-state period with the frequency held at the reduced level. This shall be followed by a ramped increase in measured system frequency of 0.3 Hz over 30 seconds, and then a further 60 seconds of steady-state operation with the frequency depressed by 0.2 Hz, as depicted in Figure 22 below.

The normal behaviour post event should be the plant returns to its pre-event operating point upon injected frequency signal removal.

This simulation will later be used during the compliance process to validate the accuracy of the model by comparing it against actual onsite test results.

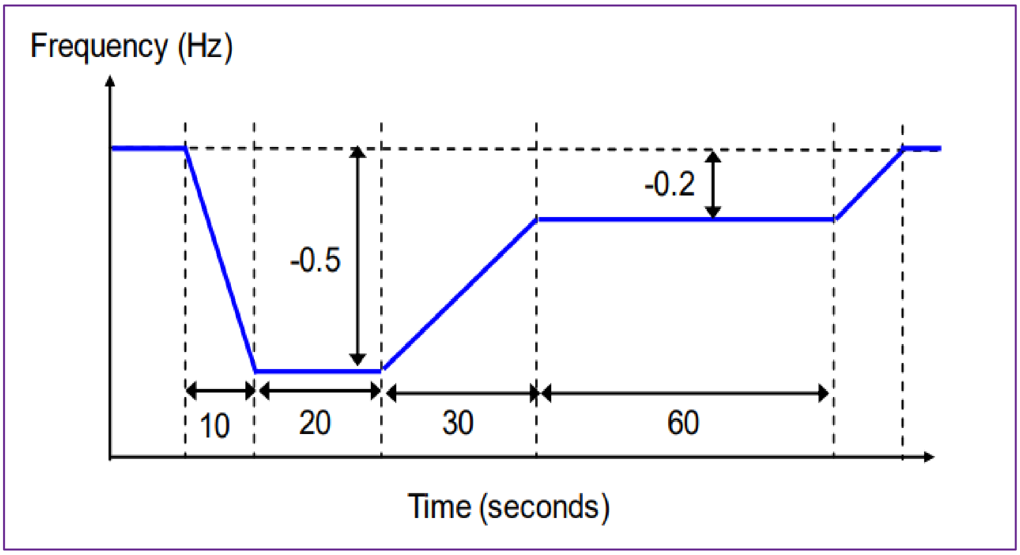


Figure 22: Model Validation Simulation

While the preceding sections provide detailed explanations of the Frequency Response related GC requirements, NESO has outlined the Grid Code compliance requirements in the form of simplified checklists against which a submission shall be assessed. Please note the checklists provided here are for guidance purposes only, and Customers are encouraged to use it. It is, however, not a mandatory requirement for the Customers to fill in and submit these checklists during compliance. The checklist can be found in **Appendix H: Grid Code Compliance Simulations Checklists .**

Appendix B: Summary of relevant ECP.A.6 Compliance Testing Requirements

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 NESO to discuss and agree an alternative test program and success criteria.

For each test, the description and purpose of the test, 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 this guidance provide outline test schedules which may assist the Generator with this activity.

NESO 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 NESO's review of submissions of the User Data File Structure (UDFS).

The tests are carried out by the Generator, or by their agent, and not by NESO. However, NESO 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 NESO.

The Generator should also provide suitable digital monitoring equipment to record all relevant test signals needed to verify the PPM performance in parallel with NESO recording equipment.

Test Notification to Control Room

The Generator is responsible for notifying the 'NESO 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 'NESO Control Centre is detailed in OC7.5 of the Grid Code. For further details relating to this procedure, refer to "Integral Equipment Tests - Guidance Notes" which can be found on NESO's Internet site, the link can also be found in **Appendix I: Important Links**:. The Integral Equipment Tests must be submitted for review and approval by the responsible Compliance Engineer.

The Generator should be aware that this interface with NESO transmission planning will normally be available in weekday working hours only. As best practice, the Generator should advise the 'NESO 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.

IET Requests for testing windows must be submitted to NESO Network Access Planning (NAP) for approval at least 28 days prior to the planned start date. Please contact NAP to request the Proforma, refer to **Appendix I: Important Links**: for the contact details.

Compliance Test Signals

The Grid Code requires that several signals are provided from compliance tests to NESO to allow assessment of compliance. The list of these signals is set out in ECP.A.4 for EU Code Users. To facilitate efficient analysis the test results should include signals requested by NESO set out in the order as indicated in the tables in **Appendix D: Test Signal Schedule and Log sheet.**

B.1. Reactive Capability Compliance Tests

Grid Code section ECP.A.6.4 describes Reactive Capability testing. The required tests should demonstrate the maximum capability of the PPM 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 modes of operation.

This section describes the Reactive Capability tests required to demonstrate compliance with the reactive capability requirements for:

- Onshore PPMs, where the reactive capability requirements are defined in Grid Code clauses ECC.6.3.2.2 and ECC.6.3.2.4.
- Offshore PPMs that provide all or part of the reactive power capability at the onshore Interface Point, as specified in ECC.6.3.2.5.2 or ECC.6.3.2.6.3.

For the avoidance of doubt, an Offshore PPM which does not provide part of the Offshore Transmission Licensee Reactive Power capability should follow the procedure described in ECP.A.6.8 and **Section C.1.** of this document for conducting Reactive Power transfer control tests and / or voltage control system.

The aim of the test is to capture performance of the PPM 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 PPM output is below this, the test should not be scheduled or attempted.
As described in Section ECP.A.6.4.2, testing shall be undertaken by adjusting the voltage set point of the voltage control scheme of the PPM or OTSDUA by the extent necessary to demonstrate compliance with the required reactive power range, at the operating points and durations specified in ECP.A.6.4.5.

In order to demonstrate that PPM 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:

Table 4: Reactive Capability Tests.

ECP.A.6.4.5 The following tests shall be completed:			
Test	Operating point		
	Reactive power	Active power	Test Duration*
1	Maximum Continuous Lagging	More than 85% of Maximum Capacity **	30 minutes

2	Maximum Continuous Leading	More than 85% of Maximum Capacity **	30 minutes
3	Maximum Continuous Leading	50% of Maximum Capacity	30 minutes
4	Maximum Continuous Lagging	50% of Maximum Capacity	30 minutes
5	Maximum Continuous Leading	20% of Maximum Capacity	60 minutes
6	Maximum Continuous Lagging	20% of Maximum Capacity	60 minutes
7* **	Unity PF (Zero Q)	Less 20% of Maximum Capacity	5 minutes
8******	Maximum Continuous Leading	MRL or 0%	5 minutes
9******	Maximum Continuous Lagging	MRL or 0%	5 minutes
*In the case of a Non-Synchronous ESM, The Company shall have discretion to reduce the duration of the tests required depending upon the capability of the energy store.			
** This test must start with active power output in excess of 85% of Maximum Capacity and must not fall below 60% of Maximum Capacity.			
*** This test only applies to systems which do not offer voltage control below 20% of Maximum Capacity.			
**** This test only applies to systems which offer voltage control below 20% and hence establishes actual capability rather than required capability.			
Plant shall be in voltage control mode and target voltage may need to be changed regularly in order to generate the maximum continuous lagging/leading reactive power			

Notes:

1. If the PPM 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 PPM 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 NESO 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.

Reactive Power MSA:

The reactive capability tests enable a mandatory services agreement (MSA) table to be drafted based on the plant's performance. The MSA table lists the maximum leading and lagging reactive power achieved at the Connection Point or USEP for a number of active power setpoints. Before the tests and during the study phase, an interim MSA is drafted. This is later replaced by the post-test MSA that is more realistic.

Below is an example of an MSA table, where the reactive capability still exists below 20% power but not necessarily if the Power Park Units are stopped:

Table 5: Sample reactive power MSA table

Point	MW	Lead (MVAR)	Lag (MVAR)
Rated MW	69	23	23
50%	35	23	23
20%	13	23	23
Below 20%	5	23	23
0	0	0	0

For information about MSA table for Offshore PPMs, please refer to Section C.1. of this document.

B.2. Voltage Control Compliance Tests

The voltage control tests for PPMs are set out in Grid Code ECP.A.6.5. As described testing should be by tapping of an upstream grid transformer and by injection to the control system reference.

It is essential that test engineers ensure the settings and parameters used during testing are identical to those applied in the simulation studies and during the review and approval of the model submission.

Pre 20% Basic Voltage control tests:

Clause ECP.A.6.2.1 outlines the requirements for the basic voltage control tests as before 20% of the Module units (or 50MW if less) has commissioned, either voltage control test ECP.A.6.5.6(i) or (ii) must be completed. For the avoidance of doubt this test shall be performed prior to the number of units commissioned make up to 20% of the total number of units in a Power Park Module in such a way that the Active Power output does not exceed 20% of Maximum Capacity.

Full Voltage Control Tests:

The Test should be performed when at least 95% of the Power Park Units and any reactive compensation units are in service.

The Grid Code permits PPMs powered by intermittent energy sources to conduct voltage control tests when the forecasted MW output reaches at least 65% of their maximum capacity. However, for clarity, this provision does not apply to ESMs, as they are not reliant on intermittent sources.

Therefore, full voltage control testing for ESMs should be carried out at maximum power, corresponding to a minimum of 95% of the units being in service.

Voltage control tests using step injection:

In the step injection tests, a series of step injections are injected to the Module voltage setpoint, steps of ±1%, ±2% and ±4% (or larger if required by The Company) shall be applied to the voltage control system setpoint summing junction. The injection shall be maintained for a minimum of 10 seconds as per the Figure below.

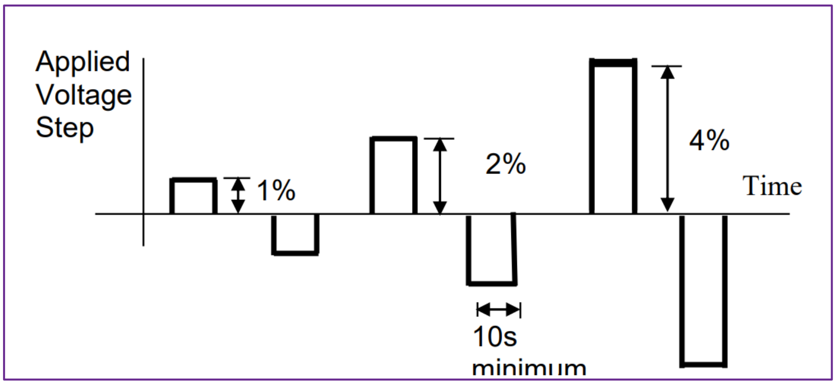


Figure 23: Voltage step tests procedure.

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

Table 6: Voltage step tests procedure.

Test	Description	Notes
V1	• Record steady state for 10 seconds • Inject +1% step in the 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 in the 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 in the 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 in the 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 in the 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 in the Voltage Reference • Hold for at least 10 seconds • Remove injection as a step • Hold for at least 10 seconds	
PPM shall be in Voltage Control at Maximum Power Output (>65% Rated MW) and near Unity Power Factor		

Voltage control tests using tap changer:

The voltage control system shall be perturbed with a series of multiple up-stream transformer taps. The time between transformer taps shall be at least 10 seconds as per the Figure below.

Where tests can be performed 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.

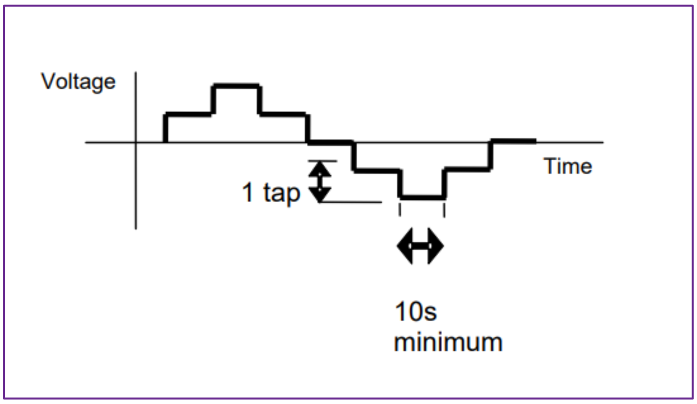


Figure 24: Tap changer tests procedure.

Table 7: Tap changer tests procedure.

Test	Description	Notes
T1	♦ Record steady state for 10 seconds ♦ Tap up 1 position on external upstream tap changer ♦ Hold for at least 10 seconds	
T2	♦ Tap up 1 position on external upstream tap changer (i.e. up 2 positions from starting position). ♦ Hold for at least 10 seconds	
T3	♦ Tap down 1 position on external upstream tap changer (i.e. up 1 position from starting position). ♦ Hold for at least 10 seconds	

T4	♦ Tap down 1 position on external upstream tap changer (i.e. at starting position). ♦ Hold for at least 10 seconds	
T5	♦ Tap down 1 position on external upstream tap changer (i.e. down 1 position from starting position). ♦ Hold for at least 10 seconds	
T6	♦ Tap down 1 position on external upstream tap changer (i.e. down 2 positions from starting position). ♦ Hold for at least 10 seconds	
T7	♦ Tap up 1 position on external upstream tap changer (i.e. down 1 position from starting position). ♦ Hold for at least 10 seconds	
T8	♦ Tap up 1 position on external upstream tap changer (i.e. return to starting position). ♦ Hold for at least 10 seconds	
PPMs in Voltage Control at Maximum Power Output (>65% Rated MW) and near Unity Power Factor		

Testing of PPMs without voltage control capability at zero active power:

As per Clause ECP.A.6.5.8, in the case of PPMs 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 PPM 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 PPM Active Power should then be reduced to zero Active Power as a ramp over a short period (60 seconds is suggested).

Testing of PPMs including switched shunt devices:

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.

Table 8: Testing of PPMs with Switched Shunt Devices.

Test	Description	Notes
V7	♦ Record steady state for 10 seconds ♦ Inject a step to the PPM Voltage Reference of sufficient size and polarity to switch in shunt device. ♦ Hold for at least 10 seconds	
	♦ Remove injection with a step of sufficient size to switch out the switched device ♦ Repeat step 1 immediately (with minimum delay)	
• Adjust voltage setpoint to a suitable operating point below switching threshold for shunt device.		

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

B.3. Fault Ride Through Testing

Section ECP.A.6.7.1 describes the procedure for conducting Fault Ride Through tests on a single Power Park Unit as required by ECP.7.2.2(d) for Power Stations with a Maximum Capacity of 100MW or greater.

Where test results from a Manufacturers Data & Performance Report as defined in ECP.11 have been accepted, this test will not be required.

The test circuit will utilise the full Power Park Unit and shall be conducted with sufficient power input resource available to produce at least 95% of the Maximum Capacity of the Power Park Unit.

The test will comprise of several controlled short circuits applied to a test network to which the Power Park Unit is connected, typically comprising of the Power Park Unit transformer and a test impedance or other decoupling equipment to shield the connected network from voltage dips at the Power Park Unit terminals, further details are provided in ECP.A.6.7

B.4. Frequency Response Compliance Tests

The main objectives of the frequency controller response tests are to establish the plant performance characteristics for compliance with the GC 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/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 the GC clauses ECP.A.6.6 Figures 1 and 2.

Important notes:

- ✓ It is essential that test engineers ensure the settings and parameters used during testing are identical to those applied in the simulation studies and during the review and approval of the model submission.
- ✓ Only one droop setting is permitted per mode of operation. For example, if a 4% droop is selected for LFSM, it must be used across all LFSM simulations and tests except those involving the de-load function. Similarly, a 3% droop selected for FSM must be consistently applied across all FSM simulations and tests.

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

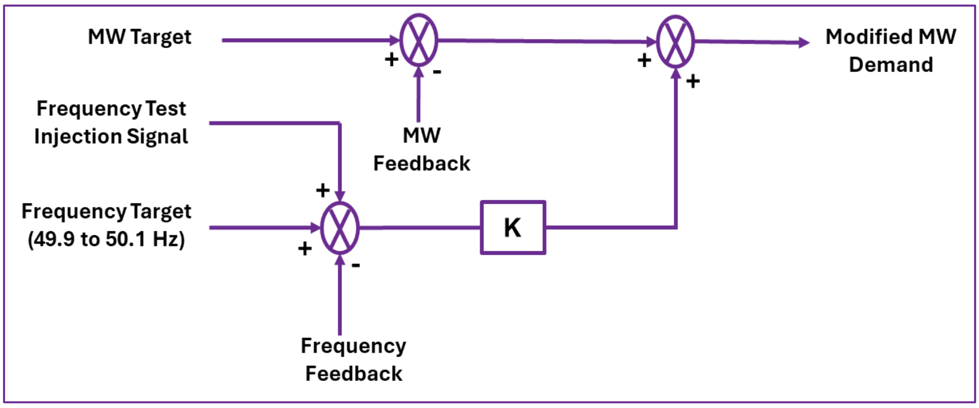


Figure 25: Typical Frequency Test Injection Signal

Different MLP Levels:

The frequency response tests are to be conducted at a number of different Module Load Points (MLP). The module load points are calculated as shown in Table 9 below unless agreed otherwise with The Company.

Table 9: Different MLP Levels

Loading Point	Calculation
Module Load Point 6 (Maximum Export Limit)	100% MEL
Module Load Point 5	90% MEL
Module Load Point 4	80% MEL
Module Load Point 3	MRL+0.6 x (MEL – MRL)
Module Load Point 2 Lower of MRL + 0.3 x (MEL – MRL) or Minimum Stable Operating Level	MRL+0.3 X (MEL – MRL) or MSOL
Module Load Point 1 (Minimum Regulating Level)	MRL

Pre 70% Tests in LFSM for PPMs with RC > 100MW:

Preliminary LFSM test applies to PPMs 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, the Grid Code ECP.A.6.3 requires two tests in Limited Frequency Sensitive mode to be completed before 70%, but at least 50% of the module has been commissioned.

Table 10: Pre 70% frequency tests procedures.

Test	Description	Frequency Injection	Notes
Injection Tests at MLP6, Plant in LFSM			
BC3	♦ Inject +2.0* Hz frequency rise over 1 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal ♦ Hold until conditions stabilise at MLP 6	+2.0 Hz	
BC4	♦ Inject +0.6 Hz frequency rise over 30 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal ♦ Hold until conditions stabilise at MLP 6	+0.6 Hz	

Preliminary Frequency Response Testing

Experience has shown that substantial delays during testing often stem from issues related to the frequency controller setup or the frequency injection method. These problems frequently lead to significant time loss and increased costs for all parties involved. To mitigate such risks, this test procedure has been developed and proven effective in preventing these situations. To avoid the need for re-testing, it is essential that both the injection method and plant control are thoroughly validated ahead of the main tests by the PPM or site contractor. A preliminary test is therefore mandatory, with full details provided in Grid Code ECP.A.6.6.4 and illustrated below.

For all tests, the target frequency to be set on the generating plant must follow instructions from the NESO Control Centre, which is typically 50.00 Hz.

With the PPM running at 80% of its Maximum Capacity with all units in service (100%), the following frequency injections to be carried out.

Table 11: Preliminary frequency tests procedures.

Preliminary Frequency Response Tests		
Test	**Frequency Injection**	**Notes**
8	♦ Inject -0.50Hz frequency fall over 10 sec ♦ Hold for a further 20 sec or longer until conditions stabilise ♦ Inject +0.30Hz frequency (increase) over 30 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal as a ramp over 10 seconds	

13	♦ Inject -0.50Hz frequency fall over 10 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal as a ramp over 10 seconds	
14	♦ Inject +0.50Hz frequency rise over 10 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal as a ramp over 10 seconds	
H	♦ Inject -0.50Hz frequency fall as a step change ♦ Hold until conditions stabilise ♦ Remove the injection signal as a step change	
I	♦ Inject +0.50Hz frequency rise as a step change ♦ Hold until conditions stabilise ♦ Remove the injection signal as a step change	
♦ Initial Power output at MLP4 ♦ Plant should be in FSM mode		

The recorded results (e.g. Freq. injected, MW, P_{avail}, and control signals) should be sampled at a minimum rate of 1 Hz to allow NESO 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 NESO for assessment at least two weeks before carrying out the full set of frequency response 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 sequences for various MLPs are outlined below in tables Table 12 through Table 17

Table 12: MLP6 frequency tests procedures.

Test	Description	Frequency Injection	Notes
Injection Tests at MLP6, Plant in FSM			
1	♦ Inject +0.10Hz frequency rise over 10 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal over 10 sec ♦ Hold until conditions stabilise at MLP 6	+0.10Hz	
2	♦ Inject -0.20Hz frequency fall over 10 sec ♦ Hold until conditions stabilise[3] ♦ Remove the injection signal over 10 sec ♦ Hold until conditions stabilise at MLP 6	-0.20Hz	
3	♦ Inject +0.20Hz frequency rise over 10 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal over 10 sec	+0.20Hz	

	♦ Hold until conditions stabilise at MLP 6		
4	♦ Inject +0.50Hz frequency rise over 10 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal over 10 sec ♦ Hold until conditions stabilise at MLP 6	+0.50Hz	
BC1	♦ Inject +2.0* Hz frequency rise over 1 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal over 1 sec ♦ Hold until conditions stabilise at MLP 6	+2.0 Hz *	
O	♦ Inject +0.5 Hz frequency rise as a step change ♦ Hold until conditions stabilise ♦ Remove the injection signal as a step ♦ Hold until conditions stabilise at MLP 6	+0.5 Hz	
BC2	♦ Inject +0.6 Hz frequency rise over 30 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal ♦ Hold until conditions stabilise at MLP 6	+0.6 Hz	
L	♦ Record normal system variation in frequency and active power of the generating unit over at least 30 minutes. Load setpoint at maximum.	No injection	
Injection Tests at MLP6, Plant in LFSM			
BC3	♦ Inject +2.0* Hz frequency rise over 1 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal ♦ Hold until conditions stabilise at MLP 6	+2.0 Hz	
BC4	♦ Inject +0.6 Hz frequency rise over 30 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal ♦ Hold until conditions stabilise at MLP 6	+0.6 Hz	

Table 13: MLP5 frequency tests procedures.

Test	Description	Frequency Injection	Notes
Injection tests at MLP 5, Plant in FSM			
5	♦ Inject -0.50Hz frequency fall over 10 sec ♦ Hold for 20 sec ♦ Inject 0.30Hz frequency rise over 30 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal over 10 sec ♦ Hold until conditions stabilise at MLP 5	Profile	

6	♦ Inject -0.20Hz frequency fall over 10 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal over 10 sec ♦ Hold until conditions stabilise at MLP 5	-0.20Hz	
7	♦ Inject +0.50Hz frequency rise over 10 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal over 10 sec ♦ Hold until conditions stabilise at MLP 5	+0.50Hz	
A	♦ Inject -0.5Hz frequency step ♦ Hold until condition stabilise ♦ Remove the step injection ♦ Hold until conditions stabilise at MLP 5	-0.5Hz	

Table 14: MLP4 frequency tests procedures.

Test	Description	Frequency Injection	Notes
Injection tests at MLP 4, Plant in FSM			
8	♦ Inject -0.50Hz frequency fall over 10 sec ♦ Hold for 20 sec ♦ Inject +0.30Hz frequency rise over 30 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal over 10 sec ♦ Hold until conditions stabilise at MLP 4	Profile	
9	♦ Inject -0.10Hz frequency fall over 10 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal over 10 sec ♦ Hold until conditions stabilise at MLP 4	-0.10Hz	
10	♦ Inject 0.10Hz frequency rise over 10 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal over 10 sec ♦ Hold until conditions stabilise at MLP 4	+0.10Hz	
11	♦ Inject -0.20Hz frequency fall over 10 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal over 10 sec ♦ Hold until conditions stabilise at MLP 4	-0.20Hz	
12	♦ Inject 0.20Hz frequency rise over 10 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal over 10 sec ♦ Hold until conditions stabilise at MLP 4	+0.20Hz	
13	♦ Inject -0.50Hz frequency fall over 10 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal over 10 sec	-0.50Hz	

	♦ Hold until conditions stabilise at MLP 4		
14	♦ Inject 0.50Hz frequency rise over 10 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal over 10 sec ♦ Hold until conditions stabilise at MLP 4	+0.50Hz	
D	♦ Inject +0.02Hz frequency fall as a step change ♦ Hold until conditions stabilise ♦ Remove the injection signal ♦ Hold until conditions stabilise at MLP 4	+0.02Hz	
E	♦ Inject -0.02Hz frequency rise as a step change ♦ Hold until conditions stabilise ♦ Remove the injection signal ♦ Hold until conditions stabilise at MLP 4	-0.02Hz	
F	♦ Inject -0.20Hz frequency fall as a step change ♦ Hold until conditions stabilise ♦ Remove the injection signal ♦ Hold until conditions stabilise at MLP 4	-0.20Hz	
G	♦ Inject 0.20Hz frequency rise as a step change ♦ Hold until conditions stabilise ♦ Remove the injection signal ♦ Hold until conditions stabilise at MLP 4	+0.20Hz	
H	♦ Inject -0.50Hz frequency fall as a step change ♦ Hold until conditions stabilise ♦ Remove the injection signal ♦ Hold until conditions stabilise at MLP 4	-0.50Hz	
I	♦ Inject 0.50Hz frequency rise as a step change ♦ Hold until conditions stabilise ♦ Remove the injection signal ♦ Hold until conditions stabilise at MLP 4	+0.50Hz	
J	♦ Inject 1.0Hz/sec frequency fall over 2 sec ♦ Hold for 30 sec ♦ Remove the injection signal ♦ Hold until conditions stabilise at MLP4	-2.0Hz	
M	♦ Record normal system variation in frequency and active power of the generating unit over at least 30 minutes	No injection	

Injection tests at MLP 4, Plant in LFSM			
BC5	♦ Inject -0.60Hz frequency fall over 30 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal over 30 sec ♦ Hold until conditions stabilise at MLP 4	-0.6Hz	
BC6	♦ Inject -1.0Hz frequency fall over 30 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal over 30 sec ♦ Hold until conditions stabilise at MLP 4	-1.0Hz	
N	♦ Record normal system variation in frequency and active power of the generating unit over at least 30 minutes ♦ Switch plant to Frequency Sensitive Mode	No injection	

Table 15: MLP3 frequency tests procedures.

Test	Description	Frequency Injection	Notes
Injection tests at MLP 3, Plant in FSM			
15	♦ Inject -0.50Hz frequency fall over 10 sec ♦ Hold for 20 sec ♦ Inject 0.30Hz frequency rise over 30 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal over 10 sec ♦ Hold until conditions stabilise at MLP 3	Profile	
16	♦ Inject 0.50Hz frequency rise over 10 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal over 10 sec ♦ Hold until conditions stabilise at MLP 3	+0.50Hz	
17	♦ Inject -0.80Hz frequency fall over 10 sec ♦ Hold for 20 sec. ♦ Inject 0.30Hz frequency rise over 30 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal over 10 sec ♦ Hold until conditions stabilise at MLP 3	Profile	

Table 16: MLP2 frequency tests procedures.

Test	Description	Frequency Injection	Notes
Injection tests at MLP 2, Plant in FSM			
18	♦ Inject -0.50Hz frequency fall over 10 sec ♦ Hold for 20 sec ♦ Inject 0.30Hz frequency rise over 30 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal over 10 sec ♦ Hold until conditions stabilise at MLP 2	Profile	
19	♦ Inject -0.20Hz frequency fall over 10 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal over 10 sec ♦ Hold until conditions stabilise at MLP 2	-0.20Hz	
20	♦ Inject 0.20Hz frequency rise over 10 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal over 10 sec ♦ Hold until conditions stabilise at MLP 2	+0.20Hz	
21	♦ Inject -0.50Hz frequency fall over 10 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal over 10 sec ♦ Hold until conditions stabilise at MLP 2	-0.50Hz	
22	♦ Inject -0.80Hz frequency fall over 10 sec ♦ Hold for 20 sec ♦ Inject 0.30Hz frequency rise over 30 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal over 10 sec ♦ Hold until conditions stabilise at MLP 2	Profile	
P	♦ Inject -0.50Hz frequency fall as a step change ♦ Hold until conditions stabilise ♦ Remove the injection signal ♦ Hold until conditions stabilise at MLP 2	-0.50Hz	
Q	♦ Inject 0.50Hz frequency rise as a step change ♦ Hold until conditions stabilise ♦ Remove the injection signal ♦ Hold until conditions stabilise at MLP 2	+0.50Hz	

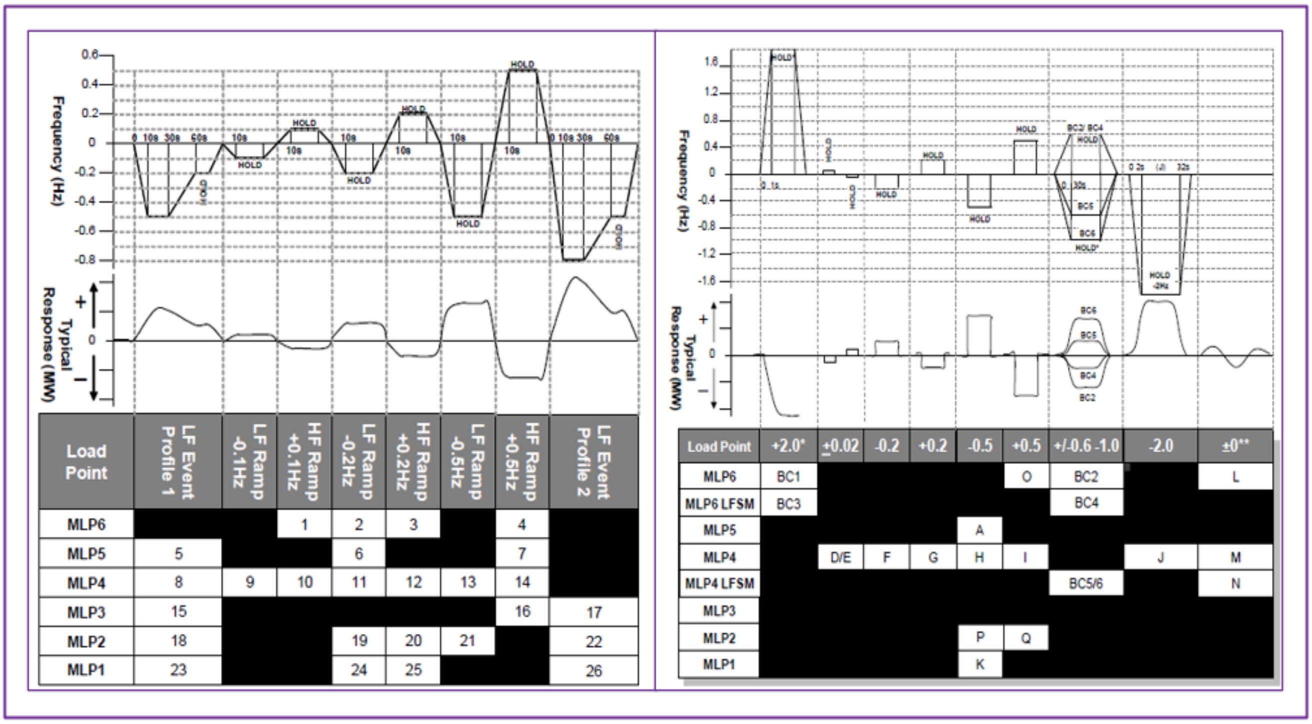
Table 17: MLP1 frequency tests procedures.

Test	Description	Frequency Injection	Notes
Injection tests at MLP 1, Plant in FSM			
23	♦ Inject -0.50Hz frequency fall over 10 sec ♦ Hold for 20 sec ♦ Inject 0.30Hz frequency rise over 30 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal over 10 sec ♦ Hold until conditions stabilise at MLP 1	Profile	
24	♦ Inject -0.20Hz frequency fall over 10 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal over 10 sec ♦ Hold until conditions stabilise at MLP 1	-0.20Hz	
25	♦ Inject 0.20Hz frequency rise over 10 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal over 10 sec ♦ Hold until conditions stabilise at MLP 1	+0.20Hz	
26	♦ Inject -0.80Hz frequency fall over 10 sec ♦ Hold for 20 sec ♦ Inject 0.30Hz frequency rise over 30 sec ♦ Hold until conditions stabilise ♦ Remove the injection signal over 10 sec ♦ Hold until conditions stabilise at MLP 1	Profile	
K	♦ Inject -0.5Hz frequency fall as a step change ♦ Hold until conditions stabilise ♦ Remove the injection signal ♦ Hold until conditions stabilise at MLP 1	-0.5Hz	

Very Important notes:

1. Tests L and M should be conducted if the system frequency feedback signal is replaced by the injection signal rather than the injection signal being added to the system frequency signal. The tests simply consist of monitoring the PPM in Frequency Sensitive Mode during normal system frequency variations without applying any injection. Test N should be conducted in all cases. All three tests should be conducted for a period of at least 30 minutes.
2. Hold period should be maintained until the Active Power (MW) output of the PPM has stabilised.
3. All frequency response test injections should be removed over the same timescale for which they were applied unless otherwise specified.
4. For ESMs in an import mode of operation, tests should be repeated with the same injections as an export mode but with the ESM importing active power from the total system.

5. For the import mode, the BC5 and BC6 tests are not mandatory. The ESM 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



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

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				

Figure 26: Frequency Response Tests

Target Frequency Control Requirements

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 NESO 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.6.6.9 and ECP.A.6.6. Figure 3 shows the target frequency test requirement to demonstrate this capability from the normal control point. It is common to use a typical load point of MLP4.

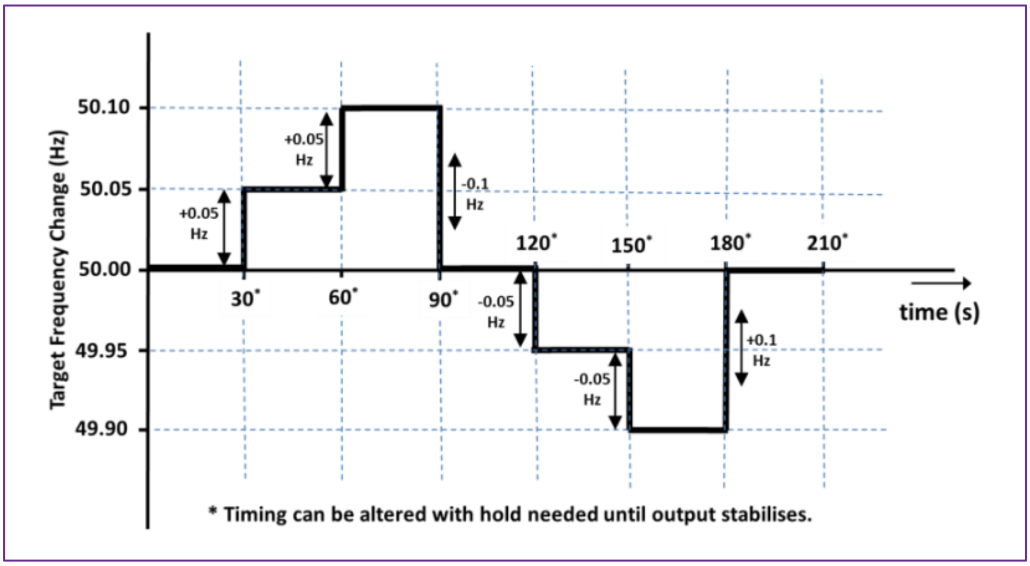


Figure 27: Target Frequency setting changes

Table 18: Target frequency test procedure

Test	Description	Frequency Injection	Notes
Injection tests at MLP 4, Plant in FSM			
TF1	♦ Operate at MLP4 for 60 seconds ♦ Alter Target Frequency to 50.05Hz ♦ Hold for 30 seconds or until conditions stabilise	50.05Hz	
TF2	♦ Alter Target Frequency to 50.10Hz ♦ Hold for 30 seconds or until conditions stabilise	50.10Hz	
TF3	♦ Alter Target Frequency to 50.00Hz ♦ Hold for 30 seconds or until conditions stabilise	50.00Hz	
TF4	♦ Alter Target Frequency to 49.95Hz ♦ Hold for 30 seconds or until conditions stabilise	49.95Hz	
TF5	♦ Alter Target Frequency to 49.90Hz ♦ Hold for 30 seconds or until conditions stabilise	49.90Hz	
TF6	♦ Alter Target Frequency to 50.00Hz ♦ Hold for 30 seconds or until conditions stabilise	50.00Hz	

Frequency Response from an Intermittent Power Source

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

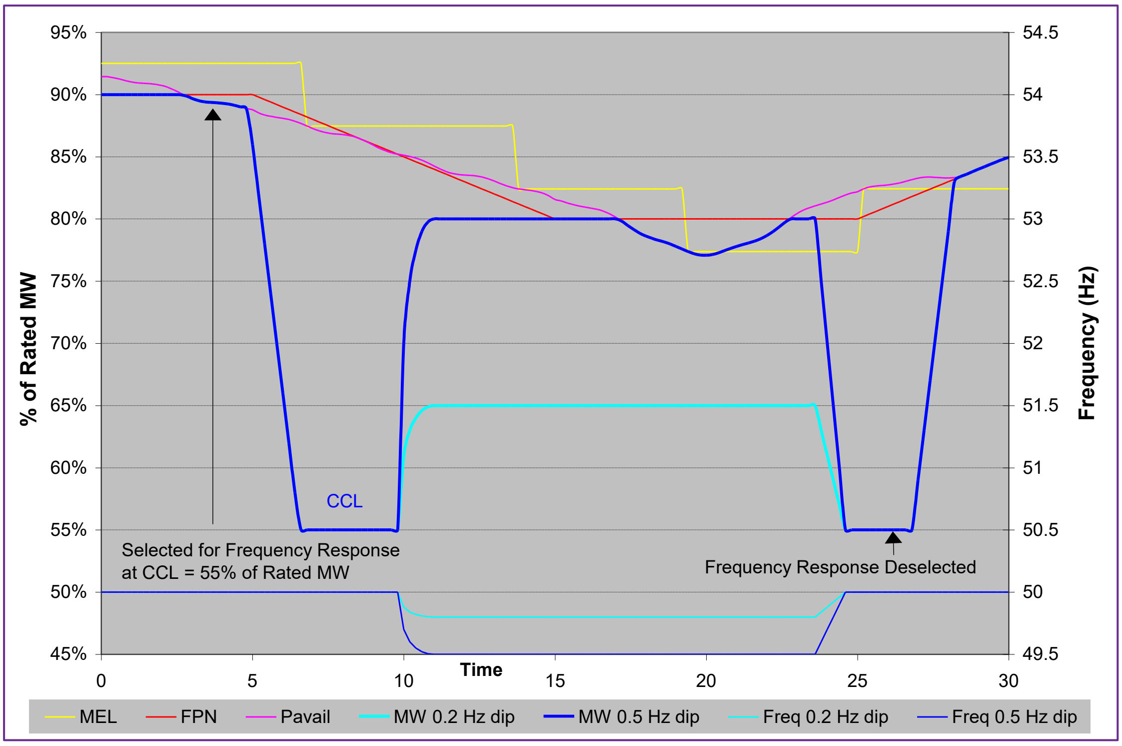


Figure 28: Expected Frequency Response with Reducing Intermittent Power Source

More detailed guidance for manufacturers on how the control system should respond to variations in power setpoint, system frequency and the intermittent power source is included in **Appendix F:Response to Frequency Changes and Intermittent Power Source Variation.**

Appendix C: Additional Technical Requirements for PPMs

C.1. Requirements for Offshore PPMs:

Reactive Capability Requirements for Offshore PPMs:

Reactive capability requirements for configuration 1 or 2 Offshore AC or DC connected PPM, the requirements of ECC.6.3.2.5 and ECC.6.2.3.6 apply respectively.

The Grid Code requires offshore Power Park Modules, where there is an offshore transmission system, to operate with zero reactive power transfer at the Offshore Grid Entry Point (OGEP) as outlined in section ECC.6.3.2.5. Please note that this only applies to configuration 1 PPMs. MSAs for configuration 2 should be discussed with the NESO.

This is on the assumption that transferring reactive power through a long cable is not efficient. Other operating regimes such as control of reactive power at an OGEP or contribution to modulation of reactive power at the onshore Transmission Interface Point (TIP) may be approved by NESO if this is demonstrated by the developer as being beneficial considering both capital and operational costs. Please see Figure 29 for the general location of TIP and OGEP for offshore PPMs.

The steady state tolerance on reactive power transfer to and from an Offshore transmission system expressed in MVAr shall be no greater than 5% of the maximum capacity. Where an EU generator seeks to provide reactive power capability in excess of the minimum requirements defined in ECC.6.3.2.5.1, such capability shall be agreed with the generator, the Offshore Transmission Licensee, and the Company and/or the relevant Network Operator.

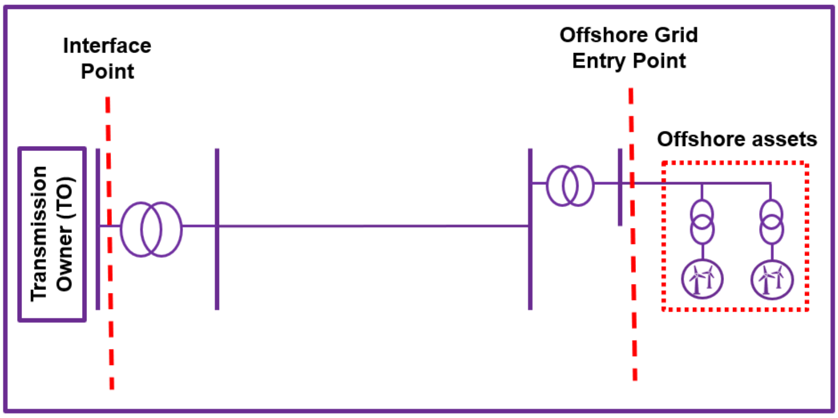


Figure 29: Point of Compliance for offshore modules.

Offshore PPM Reactive/ Voltage Control Testing:

Offshore PPMs or OTSDUAs which provide all or a portion of the Reactive Power capability as described in ECC.6.3.2.5.2 or ECC.6.3.2.6.3 as applicable are required to follow the procedure outlined in ECP.A.6.4.1, and **Section B.1.** of this document, the same procedure as Onshore PPMs for demonstrating the reactive capability.

For the avoidance of doubt, an Offshore PPM which does not provide part of the Offshore Transmission Licensee's Reactive Power capability as described in ECC.6.3.2.5.1 and ECC.6.3.2.6.1 should follow the procedure described in ECP.A.6.8 for conducting Reactive Power transfer control tests and / or voltage control system.

These tests should be carried out prior to 20% of the Power Park Units within the Offshore PPM being synchronised, and again when at least 95% of the Power Park Units within the Offshore PPM in service. There should be sufficient power resource forecast to generate at least 85% of the Maximum Capacity of the Offshore PPM.

The Reactive Power control system shall be perturbed by a series of system voltage changes and changes to the Active Power output of the Offshore PPM.

System voltage changes should be created by a series of multiple upstream transformer taps. The Generator should coordinate with The Company or the relevant network operator in order to conduct the required tests. The time between transformer taps should be at least 10 seconds as per ECP.A.6.8 Figure 1.

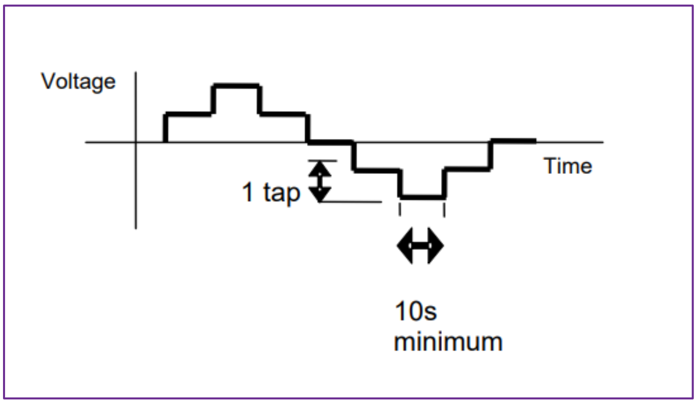


Figure 30: Transformer tap sequence for reactive transfer tests.

The Active Power output of the Offshore PPM should be varied by applying a sufficiently large step to the frequency controller Setpoint/feedback summing junction to cause a 10% change in output of the Maximum Capacity of the Offshore PPM in a time not exceeding 10 seconds.

This test does not need to be conducted provided that the frequency response tests as outlined in ECP.A.6.6 are completed.

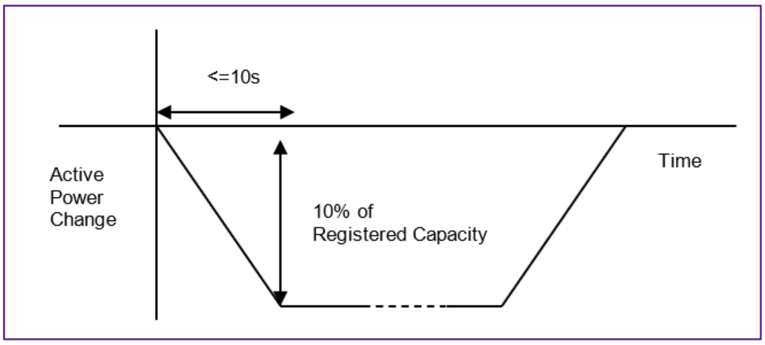


Figure 31: Active Power ramp for reactive transfer tests

MSA for Offshore Power Park Modules:

While there is a requirement for the connection to provide reactive power at the TIP, as defined by Figure-ECC.6.3.2.4(c), this requirement is for the OFTO. Therefore, there is no MSA for it.

The MSA for the Offshore plant is based on the reactive power at the Commercial Boundary (which, is generally on the LV side of the Offshore transformer although it is possible for the Commercial Boundary to be at an agreed location with the NESO). As mentioned above, even though ECC.6.3.2.5 requires zero reactive power at the Offshore Grid Entry Point, other schemes may be agreed with the NESO and OFTO. As such, these schemes are broadly divided into four scheme categories, listed in the table below, and the MSAs are defined accordingly. The figure below shows an example of the reactive power provision schemes.

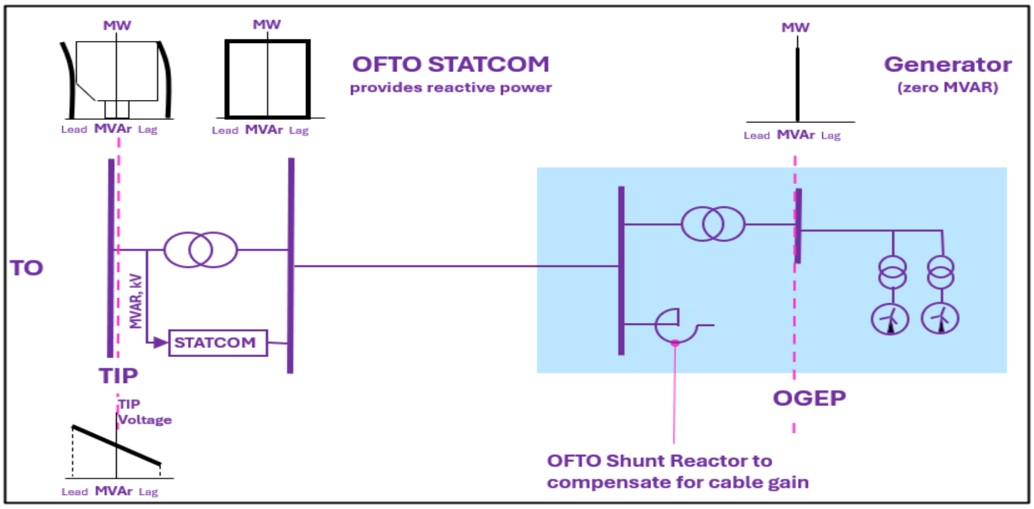


Figure 32: Example of Reactive Power Provision Schemes.

Table 19: Schemes of Configuration 1 Offshore PPMs

Configuration 1 Offshore PPMs				
	Reactive Power at TIP	**Reactive Power at OGEP**	**MSA**	**Testing Requirement**
Sch. 1	Provided wholly by the OFTO	0 MVAr, provided by Offshore PPM. Cable gain compensated by assets (such as shunt reactors). WT is under Q control mode.	Zero	ECP.A.6.8
Sch. 2	Provided wholly by the OFTO	Some reactive power provided by Offshore PPM to compensate for cable gain. WT is under Q control mode.	Yes (see discussion below)	ECP.A.6.4
Sch. 3	Provided wholly by Offshore PPM (on behalf of OFTO)	All reactive power provided by Offshore PPM to fulfil requirements at IP.	Yes	ECP.A.6.4
Sch. 4	Provided in part by OFTO and in part by Offshore PPM	Some reactive power provided by Offshore PPM to fulfil requirements with STATCOM and SVC at IP.	Yes	ECP.A.6.4

Scheme 1 is the recommended scheme in the Grid Code. Since the PPM provides zero reactive power at the OGEP, the MSA is a table of zeroes.

In Scheme 2, the PPM provides reactive power at the OGEP to compensate for the cable gain. However, since it does not contribute to reactive power at the TIP, the MSA table has little significance.

Schemes 3 and 4 are where the PPM contributes, at least in part, to reactive power at the TIP. The MSA tables are drafted depending on the reactive power at the commercial boundary.

When carrying out the reactive capability tests at the Transmission Interface Point (TIP) onshore, the measurements for the output from the offshore wind turbines will be requested by NESO. This will help establish the full picture.

Fault Ride Through for Offshore PPMs:

Short-duration fault simulations (up to 140 ms) should be applied for offshore PPMs, at both the GEP and the Transmission Interface Point (TIP).

For OTSDUW DC Converters subject to faults and voltage disturbances at the Grid Entry Point or User System Entry Point or Interface Point or HVDC Interface Point, including Active Power transfer capability, shall be specified in the Bilateral Agreement. Users to agree with NESO the long duration fault cases that will be studied in alignment with their BCA that their connection can withstand depending on chopper resistors implemented in their design.

C.2. Requirements for BESS:

In addition to all the previous sections, this section outlines the technical requirements that apply uniquely to BESS, reflecting their bidirectional operation characteristics. It specifies the expected performance of the BESS control system, its response in both import and export modes, and any additional obligations arising from battery augmentation, or technology-specific limitations. These requirements ensure that BESS installations operate safely, predictably, and in full compliance with Grid Code obligations under all system conditions.

Compliance in Import Mode of Operation:

Section ECC.6.3.1 in the European connection conditions outlines that the requirements that apply to Synchronous PGMs also extend to Synchronous ESMs, and Similarly, the requirements for PPMs are applicable to non-synchronous ESMs.

The clause also highlighted that the requirements for ESMs remain in effect regardless of whether the module is operating in import or export mode with respect to the Total System, hence any ESM either Synchronous or Non-Synchronous ESM should demonstrate compliance with the GC requirements in both modes of operation (i.e. import and export) through the full suite of simulations and tests.

Compliance of Grid Forming BESS:

For BESS projects providing Grid Forming services, the BESS is required to demonstrate compliance with the Grid Code requirements outlined in ECP.A.3 as well as ECP.A.6 for studies and tests in addition to various grid forming requirements in ECC.6.3.19, ECP.A.3.9 and ECP.A.9. For more information please also refer to the Guidance Notes for Grid Forming Plant on The Company website, links can also be found in **Appendix I: Important Links**:.

It worth mentioning that Grid Forming services are currently procured via Pathfinder contracts, with additional simulation requirements addressed under the Stability Pathfinder framework. It is strongly advised that Grid Forming developers proactively engage with the designated compliance engineer earlier in the compliance process to clarify the simulation expectations for their respective projects.

BESS Augmentation

ESMs deploying Battery Energy Storage Systems (BESS) are normally subject to degradation in performance over the course of their lifetime. This degradation depends upon multiple factors including but not limited to the charge/discharge cycles, energy storage usage strategy deploying state of charge and depth of discharge techniques, temperature etc. This is why a BESS site may require energy augmentation over time by adding additional energy capacity to compensate for the lost energy and maintain the performance at the Point of Connection. This augmentation may take place after the BESS is placed in commercial operation either once or multiple times throughout the life of the plant.

DC Augmentation

This type of augmentation is done by adding direct current (DC) energy capacity in the form of additional cells to the battery on the DC side. In DC Augmentation, the number of inverter units stays the same as the augmentation is deployed at the DC side of inverters. The User is required to notify NESO of this change which may/may not require a potential amendment to the Bilateral Agreement. For Compliance purposes, the User shall be required to submit the updated DRC data along with the RMS and EMT models of their as-built plant to NESO for approval. The post-augmented models shall be validated with respect to the post-commissioning onsite test results as a reference to demonstrate the augmented BESS behaviour stays the same.

AC Augmentation

This type of augmentation is done by adding alternating current (AC) energy capacity in the form of additional DC battery and inverter units. The AC augmentation could occur at the Low Voltage (LV) or Medium Voltage (MV) terminals. The User is required to notify NESO of this change which may require a potential amendment to the Bilateral Agreement. NESO may also require a technical re-assessment of the connection to specify any additional technical requirements to the Bilateral Agreement. The User shall be required to submit the updated DRC data along with the RMS and EMT models of their as-built plant to NESO for approval. The post-augmented models shall be validated with respect to the post-commissioning onsite test results as a reference to demonstrate the augmented BESS behaviour stays the same. For AC augmentation, it should be demonstrated that the plant's existing inverter units are adjusted using software controls as new inverter units are added to maintain the equivalency of the plant. The User would be required to carry out additional simulation studies which shall be done by overlaying the simulation results of pre and post augmented plant. The detailed scope of studies shall be agreed with the NESO Compliance Team which shall include but not be limited to the voltage, frequency and fault ride through performance.

BESS in import mode responding to low frequency events:

Clause ECC.6.3.7.2.3.1 of the GC outlines that the Electricity Storage Modules are primarily expected by default to comply with all requirements listed in ECC.6.3.7.2.3.1 (a)–(f) while operating in the import mode, except where it has been agreed with NESO that an ESM is unable to meet these requirements in which case the requirements of OC6.6.6 shall apply, as follows.

1. ECC.6.3.7.2.3.1: De-load function:
2. OC6.6.6: Low Frequency Demand Disconnection (LFDD) function:

De-load function requirements:

Each Electricity Storage Module is required to be:

- Capable of automatically maintaining its Active Power output within the shaded operating region shown in Figure ECC.6.3.7.2.3(a) until the stored energy has been depleted.
- The Droop shall be between 0.6% and 1.2%
- Automatically respond in accordance with the characteristic of Figure ECC.6.3.7.2.3(a) when the System Frequency falls to 49.5Hz and below.
- The reduction in Active Power import and the transition to the final value of Active Power output shall be continuously and linearly proportional to the reduction in Frequency below 49.5 Hz. Active Power output must be provided increasingly with time.
- As much as possible of the proportional reduction in Active Power import must be achieved within 10 seconds of the time of the Frequency decreases below 49.5 Hz.
- The initial delay should be less than 2 seconds.
- Where the System Frequency is falling to 49.2Hz, and the ESM is not capable of making a transition from import to export within 20 seconds, then it shall then immediately reduce its Active Power import to zero.
- If the ESM has not achieved at least a zero Active Power import when the System Frequency has reached 48.9Hz, it shall be instantaneously tripped.

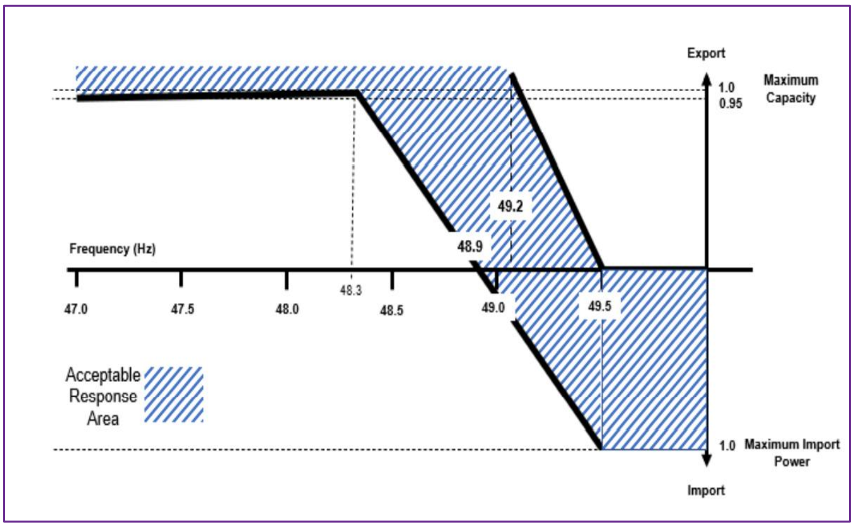


Figure 33: Active power response when operating in LFSM-U import mode

- Where an ESM 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 34 in respect of the Active Power output and Active Power import. For example, Figure 34, 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 ESM 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 ESM is permitted to reduce Active Power output so long as it is operating within the shaded area above 49.5Hz shown in Figure 34 unless the ESM 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

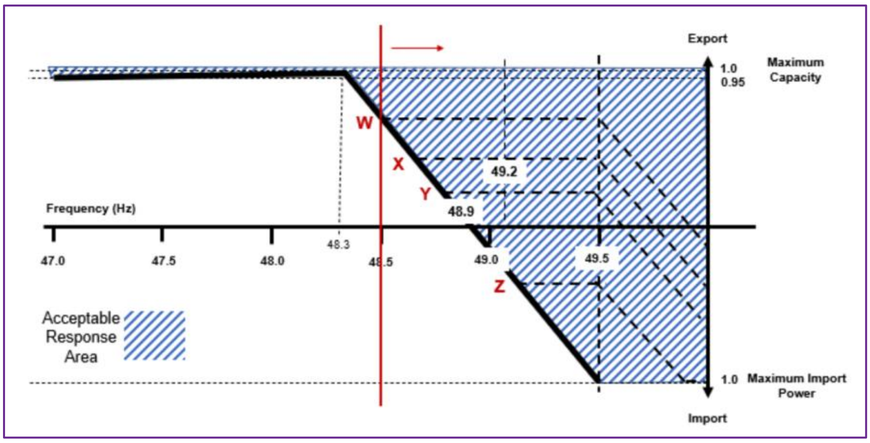


Figure 34: Active Power performance with increasing frequency

- While the Grid Code does not explicitly define a ramp-out rate following frequency recovery (i.e. above 49.5 Hz), it is strongly recommended, in the interest of transmission system security and stability, that a non-aggressive ramp rate is applied. A ramp-out rate in the range of 0.1–0.2 pu/sec is considered appropriate.
- To avoid any mixing between the de-load function requirements and normal LFSM requirements and to avoid interaction between de-load function algorithms while the ESM is operating in export mode, clause ECC.6.3.7.2.3.3 insists that the requirements of ECC.6.3.7.2.1 and ECC.6.3.7.2.2 shall apply where an ESM is exporting Active Power to the Total System (including zero) and the System Frequency falls below 49.5Hz.

De-load function Simulations:

For ESMs that meet the droop requirements outlined in ECC.6.3.7.2.3, simulation studies must be submitted to demonstrate the ESM's response under LFSM-U during operation in an import mode. In summary six simulations are required as follows:

- ESM response to a frequency injection of 49Hz, where:
  - ESM is initially operating at its maximum import power
  - ESM is initially operating at 40% of its maximum import power
- ESM response to a frequency injection of 48.8Hz, where:
  - ESM is initially operating at its maximum import power
  - ESM is initially operating at 40% of its maximum import power
- ESM response to a frequency injection of 48.3Hz, where:
  - ESM is initially operating at its maximum import power
  - ESM is initially operating at 50% of its maximum import power

Details and procedure of the required simulations are as outlined below:

These studies should begin with the ESM operating at its maximum import power. A simulation signal shall be applied that ramps the system frequency from 50 Hz to 49.0 Hz at a rate of 2 Hz/s. The frequency shall be maintained at 49.0 Hz for 60 seconds, then ramped back to 50 Hz over a 10-second period, as illustrated in Figure 35. The results must show a corresponding reduction in active power import in line with ECC.6.3.7.2.3.1.

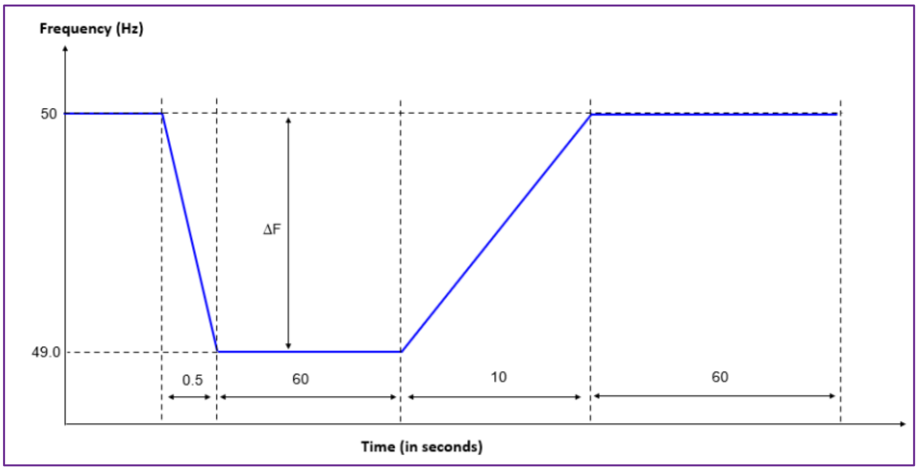


Figure 35: De-load function simulation frequency = 49Hz

This simulation shall be repeated with a minimum test frequency of 48.8 Hz, as shown in Figure 36

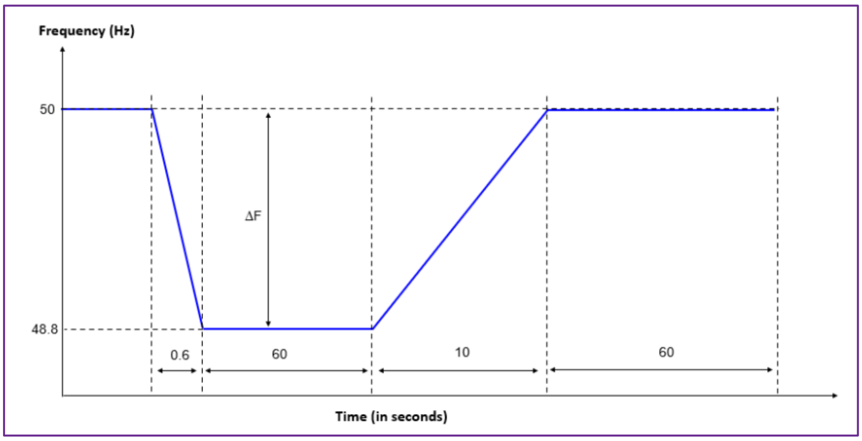


Figure 36: De-load function simulation frequency = 48.8Hz

Additionally, the above simulations must be repeated with the ESM operating at 40% of its maximum import power.

To further check performance under extreme frequency conditions, an additional set of simulation studies shall be submitted. These studies should also begin with the ESM operating at maximum import power in LFSM. The simulation signal shall ramp the system frequency from 50 Hz to 48.3 Hz over 20 seconds, hold at 48.3 Hz for 60 seconds, and then ramp back to 50 Hz over another 20 seconds, as shown in Figure 37.

This simulation shall also be repeated with the ESM operating at 50% of its maximum import power.

The normal behaviour post event should be the plant returns to its pre-event operating point upon removal of the injected frequency signal.

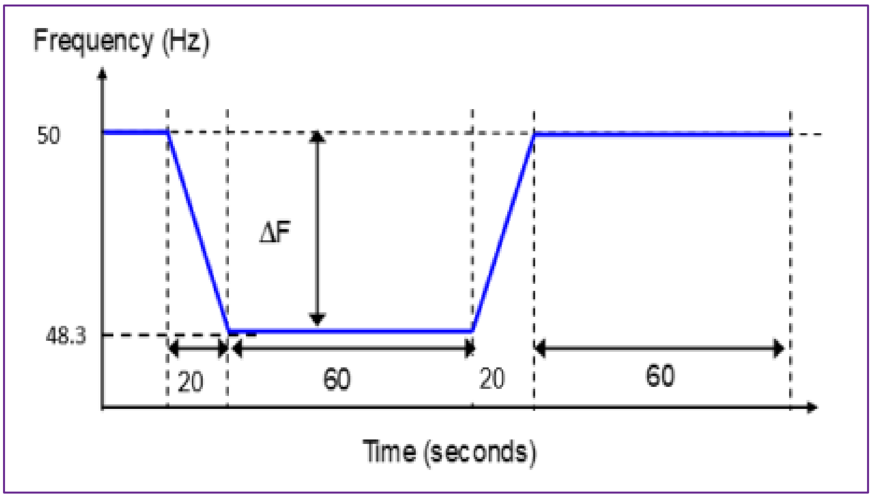


Figure 37: De-load function simulation frequency = 48.3Hz

De-load function testing:

To evaluate the performance of the ESM during low system frequency events, the following steps shall be carried out, in total four tests should be carried out:

- ESM response to a frequency injection of 49Hz, where:
  - ESM is initially operating at its maximum import power
  - ESM is initially operating at 40% of its maximum import power
- ESM response to a frequency injection of 48.8Hz, where:
  - ESM is initially operating at its maximum import power
  - ESM is initially operating at 40% of its maximum import power

Details and procedure of the required tests are as outlined below:

Before the test begins, the ESM must be operating at its Maximum Import Power while in Limited Frequency Sensitive Mode, then a test signal shall be applied that ramps the system frequency from 50.00 Hz down to 49.0 Hz at a rate of 2 Hz/s. The frequency shall be held at 49.0 Hz for 60 seconds, then ramped back to 50.00 Hz over a period of 10 seconds, as illustrated in Figure 38.

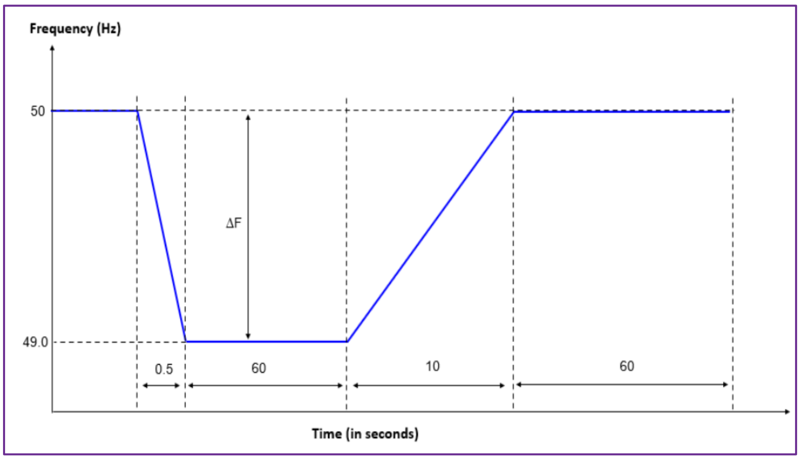


Figure 38: De-load function test frequency = 49Hz

The steps outlined above shall be repeated, but with the minimum test frequency reduced to 48.8 Hz, as shown in Figure 39.

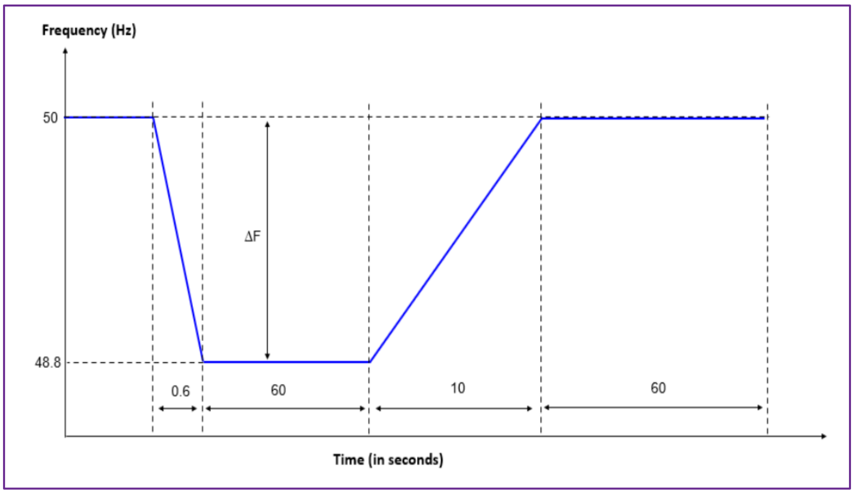


Figure 39: De-load function test frequency = 48.8Hz

All tests described above shall also be repeated with the ESM operating at 40% of its Maximum Import Power.

Low Frequency Demand Disconnection (LFDD) function:

Users who have agreed with The Company to satisfy the requirements of OC6.6.6 must provide automatic low Frequency disconnection, which shall be split into discrete blocks. The number and size of blocks and the associated low Frequency settings will be specified by NESO by week 24 each calendar year following discussion with the relevant parties in accordance with the relevant BCA.

For example, an ESM rated at 50MW would be expected to disconnect 12.5 % of RC for every 0.05 Hz drop in system frequency as shown below.

1. 49.5Hz: 6.25MW 12.5% of RC
2. 49.45Hz: 6.25MW 12.5% of RC
3. 49.4Hz: 6.25MW 12.5% of RC
4. 49.35Hz: 6.25MW 12.5% of RC
5. 49.3Hz: 6.25MW 12.5% of RC
6. 49.25Hz: 6.25MW 12.5% of RC
7. 49.2Hz: 6.25MW 12.5% of RC
8. 49.15Hz: 6.25MW 12.5% of RC

All the demand expected to be tripped at 49.15Hz.

Additional Load Rejection Simulations for ESMs in Demand (Import) and zero Active Power modes:

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

1. ECP.A.3.6.7(i): Load Rejection at zero active power output.
2. ECP.A.3.6.7(ii): Load Rejection at 50% active power output import.
3. ECP.A.3.6.7(iii): Load Rejection at 100% active power output import.

At the beginning of the simulation, the ESM should operate at a power level appropriate to the scenario being tested.

The system configuration should include the ESM and a fictitious synchronous generator supplying two loads: Load 1 and Load 2. These loads must be tuned so that, under normal conditions, the system is balanced in terms of generation and demand.

- Load 1 should act as a negative load (i.e. a generator) that supplies the ESM's import demand.
- Load 2 should match the output power of the synchronous generator.
- A third load, Load 3, should be introduced as a negative load to simulate a load rejection event acting to trigger a frequency rise. Its value must be calculated to ensure that the ESM's post-event power output aligns with its declared droop settings.

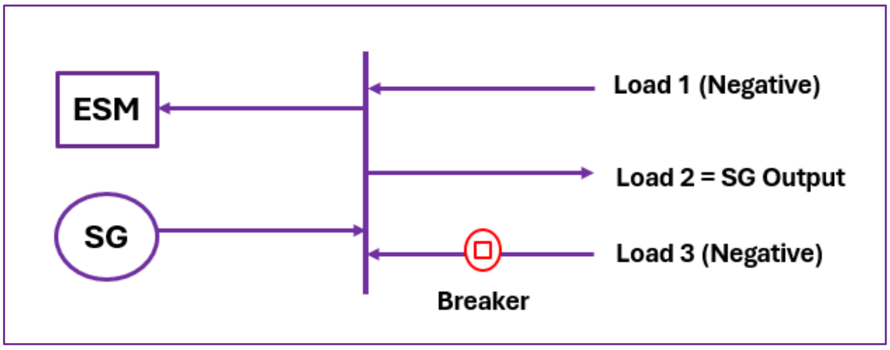


Figure 40: Load rejection arrangement in import

In this condition, and without any governor response from the synchronous generator, the ESM should regulate its active power output in accordance with its declared droop settings, demonstrating proper frequency control behaviour.

Similar to export mode, the value of load 3 should be calculated along with the required change in MW in ESM power level according to the droop settings.

Table 20: Examples for Loads Calculations in import

Mode	Droop	Max. Change in Frequency (Δf)	Req. Change in Active Power (ΔP)	Post-event ESM Output	Load 1	Load 2	Load 3
Scenario 1: ESM is initially at zero active power level							
LFSM	10%	2Hz	32MW	-32MW	00	Match SG	-32MW
LFSM	4%	2Hz	80MW	-80MW	00		-80MW
FSM*	5%	2Hz	80MW	-80MW	00		-80MW
FSM*	4%	2Hz	100MW	-100MW	00		-100MW
Scenario 2: ESM is initially at 50% active power import level							

LFSM	10%	2Hz	32MW	-82MW	-50MW	Match SG	-32MW
LFSM	4%	2Hz	80MW	-100MW	-50MW		-50MW
FSM*	5%	2Hz	80MW	-100MW	-50MW		-50MW
FSM*	4%	2Hz	100MW	-100MW	-50MW		-50MW
***FSM deadband of +/-15mHz is not considered in the calculation for simplicity.**							

ECP.A.3.6.7(i): Load Rejection at zero active power output.

The ESM should initially be operating at zero Active Power output and have sufficient capability so that it is possible to operate the ESM at maximum capacity and maximum Import power.

The simulation studies as detailed in ECP.A.3.6.7 should then be conducted to ensure the ESMs Active Power output achieves its Maximum Import power in line with the droop and response time settings as declared by the ESM.

ECP.A.3.6.7(ii): Load Rejection at 50% active power output import.

The ESM should be operating at 50% of its Maximum Import Power and have sufficient capability so that it is possible to operate the ESM at Maximum Capacity and Maximum Import Power.

The simulation studies should be conducted to ensure the ESMs Active Power output achieves its Maximum Import Power in line with the Droop and response time settings as declared by the Generator.

ECP.A.3.6.7(ii): Load Rejection at 100% active power output import.

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

In this scenario, the synchronous generator shall operate in governor control mode. At the beginning of the simulation, the ESM is importing 100 MW, equivalent to -1pu for a 100 MW ESM. Load 1 is set to -1pu (-100 MW), and Load 3 is configured as -10 MW (or another negative value sufficient to induce a frequency rise).

Upon closing the breaker, Load 3 connects to the busbar, resulting in an increase in system frequency. Since the ESM is already importing at full capacity, it must not respond to this frequency change. Instead, the SG should regulate the frequency by reducing its power output accordingly.

Operational Constraints & Testing Limitations for ESMs:

- ✓ In case of a Non-Synchronous ESM, where a compliance test requires operation for a specified duration, NESO shall have discretion to reduce the test duration where this is necessary due to the inherent energy limitations of the storage system, provided the shortened test still demonstrates the required performance characteristics.

- ✓ For ESMs operating in import mode, tests and simulations should be repeated using the same injection profiles as in export mode, but with the ESM importing active power from the system.
- ✓ Although the Grid Code permits Power Park Modules (PPMs) to undertake certain tests when their forecasted MW output reaches a percentage of maximum capacity, this provision applies only to PPMs powered by intermittent energy sources (such as wind or solar). It does not apply to BESS, which are expected to undertake tests at the required output levels regardless of prevailing system conditions.

C.3. Requirements for PPMs fitted with PSS:

As per clause ECP.A.6.1.1(iii), where a Power System Stabiliser (PSS) is fitted, NESO may require additional tests. Although the fitting of Power System Stabilisers on non-synchronous plant is a rarity, one may be provided within the control system by a manufacturer or NESO may specify the requirement in the Bilateral Agreement. The testing process outlined in this section is based largely on that employed on synchronous plant, which is believed to be comparable. However, Generators should anticipate the possibility that an alternative testing regime may be developed in discussion with NESO.

NESO will not permit PSS commissioning until the tuning methodologies and study results used in any PSS settings proposal have been provided to NESO. A report on the PSS tuning should be provided along with the proposed test procedure. Based on the information submitted, NESO will meet with the Generator to discuss and agree the initial PSS settings for commissioning.

The suitability of the tuning of any PSS is checked in both the time and frequency domains. In the time domain, testing is achieved by applying a small voltage step change on a module basis. Comparisons are made between performance with and without the power system stabiliser in service. For analysis in the frequency domain, a bandwidth-limited (200mHz-3Hz) random noise injection should be made to the Power Park Module voltage reference. The generator should provide a suitable band limited (200mHz-3Hz) noise source to facilitate noise injection testing. The random noise injection will be carried out with and without the PSS in service to demonstrate damping. The PSS gain should be continuously controllable (i.e. not discrete components) during testing. The suitability of the PSS gain will also be assessed by increasing the gain in stages to 3x the proposed setting.

The tests will be regarded as supporting compliance if:

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

PSS testing is additional to the Power Park Module Voltage Control Tests.

Power Park Module PSS Test Procedure

The PSS Test should be done when at least 95% of the Power Park Units and any reactive compensation units are in service. Wind conditions should be such to allow power production from the Module of at least 65% Registered Capacity.

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

Table 21: PPMs PSS Test Proposal.

Test	Description	Notes
Power Park Module in Voltage Control at Maximum Power Output (>65% Rated MW) and near Unity Power Factor PSS Not in Service		
PSS1	♦ Record steady state for 10 seconds. ♦ Inject +1% step to PPM voltage reference and hold for at least 10 seconds. ♦ Remove step returning PPM voltage reference to nominal and hold for at least 10 seconds.	
PSS2	♦ Record steady state for 10 seconds. ♦ Inject +2% step to PPM voltage reference and hold for at least 10 seconds. ♦ Remove step returning PPM voltage reference to nominal and hold for at least 10 seconds	
PSS3	♦ Inject band limited (0.2-3Hz) random noise signal into voltage reference and measure frequency spectrum of Active Power. ♦ Remove noise injection.	
Switch On Power System Stabiliser		
PSS4	♦ Record steady state for 10 seconds. ♦ Inject +1% step to PPM voltage reference and hold for at least 10 seconds. ♦ Remove step returning PPM voltage reference to nominal and hold for at least 10 seconds.	
PSS5	♦ Record steady state for 10 seconds. ♦ Inject +2% step to PPM voltage reference and hold for at least 10 seconds. ♦ Remove step returning PPM voltage reference to nominal and hold for at least 10 seconds	
PSS6	♦ Inject band limited (0.2-3Hz) random noise signal into voltage reference and measure frequency spectrum of Active Power. ♦ Remove noise injection.	
PSS7	♦ Increase PSS gain at 30second intervals. i.e. x1 – x1.5 – x2 – x2.5 – x3 and observe that the active power oscillations do not get too much. ♦ Return PSS gain to initial setting.	
Repeat Module Voltage Control Tests with PSS in service.		

C.4. Requirements for Staged Connections:

Users may be subject to temporary TEC restrictions due to network constraints, which are expected to be lifted after a defined period following commissioning. To support effective planning, it is essential that Users share their site commissioning programme and engage early with the Contract Manager, Connection Compliance Manager (CCM), or Compliance Engineer (CE). Early communication should clearly outline the proposed staged commissioning approach and highlight any transmission network constraints that could affect TEC or the commissioning programme.

Case 1: Number of Inverters/PPUs Unchanged in between Stages:

In this scenario, User would have commissioned all the Power Park Units within a Power Park Module in Stage 1 however are subject to the temporary TEC restriction (e.g. By the relevant TO) which shall be lifted shortly after the issuance of ION. As shown in Figure 41, output is restricted to 80% of full TEC in Stage 1 with all the Power Park Units in service. The User is able to reach the full 100% TEC once the restriction is lifted in Stage 2. For compliance purposes, the User is required to submit a full suite of compliance simulation studies as per Grid Code requirements conducted at 100% Registered Capacity. In addition, the User shall also be required to repeat Fault Ride Through (FRT) studies at reduced TEC as a foreseeable running arrangement in accordance with ECP.A.3.5.

RMS and EMT models of the Power Park Module shall be provided such that they include appropriate controllability to reflect the stages of the project. For testing, the 20% voltage test need only be completed once at the reduced Registered Capacity or Maximum Capacity, with the full suite of on-site testing to be completed once the TEC restriction has been lifted.

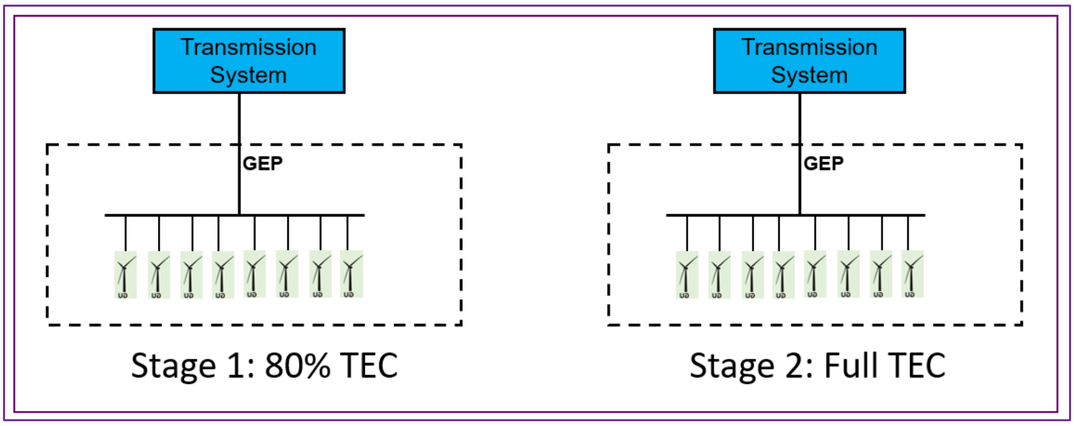


Figure 41: Staged Connection (limited TEC).

Case2: Additional Inverters/PPUs between Stages:

A User may choose to commission a partial site (i.e. Stage 1 with a reduced number of inverters or Power Park Units) at an early stage, with the remaining Units scheduled to be commissioned at a later date.

When the Stage 2 Power Park Units are ready to be commissioned, the existing Power Plant Controller (PPC) often requires reconfiguration to ensure coordinated control across all (existing from Stage 1 and new from Stage 2) Units within a Power Park Module. Please refer to Figure 42 demonstrating the difference in stages whilst connecting a Power Park Module. The new Units from Stage 2 may be different in terms of technical specifications compared to existing Stage 1 Units. Regardless, the compliance approach for such connections is outlined below.

Compliance for Stage-1:

As the Grid Code compliance is assessed in respect of each Power Park Module, a full suite of compliance simulation studies is required for the Power Park Module commissioned in Stage 1.

RMS and EMT models that are truly and accurately representing the commissioned Power Park Module as built must also be provided in accordance with PC.A.9 requirements.

The 20% voltage control test shall be completed for Stage 1 following the issue of the ION. Where there are significant delays to Stage 2 commissioning with scheduled commissioning extending beyond the 24month ION period, the User may be advised to complete the full suite of on-site compliance testing for Stage 1.

Compliance for Stage-2:

When the additional Power Park Units are ready to be commissioned, the total fault contribution from such a Power Park Module will change, with the existing PPC configuration also subject to modification. As compliance is assessed in respect of each Power Park Module, where the combined Units from stage 1 and 2 forms a single Power Park Module, a full suite of compliance simulation studies will be required for the modified Power Park Module. In the case where the additional Power Park Units belong to different technology, please refer to the Guidance Notes for Co-location of Different Technologies. Where the new Power Park Units substantially alter the operation of the Power Park Module, NESO may request additional compliance simulation studies that can be agreed on case-by-case basis in the Compliance Stage.

User shall also be required to submit the updated RMS and EMT models of the modified Power Park Module in accordance with PC.A.9 requirements.

Following issuance of the ION for Stage 2, the 20% voltage control test (and the 70% frequency response test where applicable) shall be required. The ION restriction will apply for the modified Power Park Module. These tests shall be conducted by using the combination of Power Park Units from both Stage 1 and Stage 2. A full suite of onsite compliance testing shall be required for the modified Power Park Module. This requirement applies regardless of whether Stage 1 compliance testing hasn't been completed or whether Stage 1 has achieved FON.

Consider a 100MW Power Park Module under Stage 1 with an additional 100MW Units to be installed and commissioned in Stage 2. In this example, the Power Park Module in Stage 1 completed the 20% voltage control and 70% frequency response tests and is now operating unrestricted at 100MW. The User hasn't completed the full suite of onsite compliance testing. When Stage 2 Units are commissioned, the modified Power Park Module will be restricted to 20% of the total output of 200MW (Stage 1 + Stage 2) before the 20% voltage control tests are completed. These tests shall be conducted by combining the Units from both Stage 1 and Stage 2 such that the modified PPC is able to smoothly co-ordinate the required voltage control response between the Stage 1 and Stage 2 Units and deliver at the GEP. The same philosophy can be applied for completing the 70% frequency response tests. When the Stage 2 receives an unrestricted ION, the entire Power Park Module can now export the full output of 200MW. The remaining onsite compliance testing for such a Power Park

Module can now be completed with respect to the Maximum Capacity of 200MW before a FON can be issued.

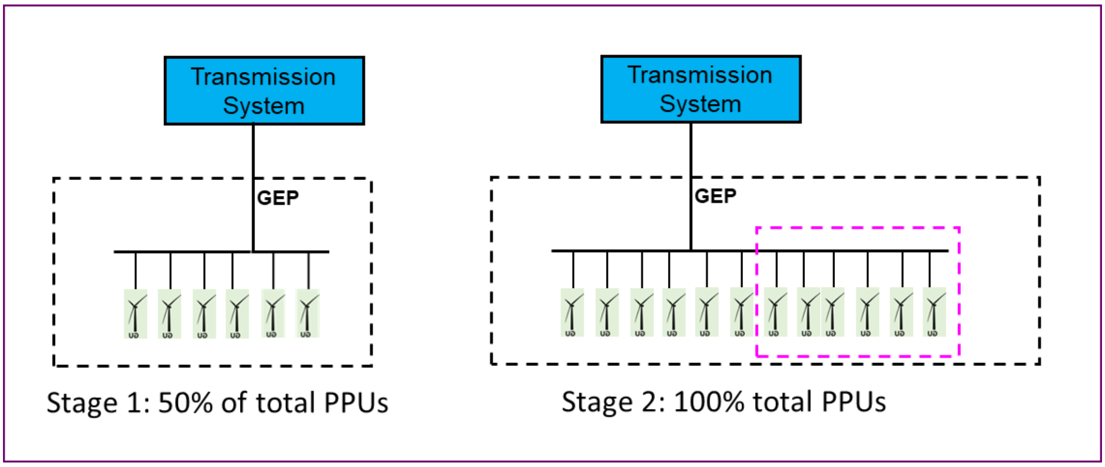


Figure 42: Staged Connection (Additional Units).

Where the new Power Park Units substantially alter the operation of the Power Park Module, NESO may request additional compliance tests that can be agreed on a case-by-case basis in the Compliance Stage.

Appendix D: Test Signal Schedule and Log sheet

D.1. Compliance Test Signal Schedules

The purpose of this section is to set up the general formatting rules for the test results submitted to NESO for compliance purposes, section ECP.A.4 in the grid code outlines the signals to be submitted. It is also worth highlighting the key points as below:

1. It is crucial to follow GC requirements in terms of sampling rates & the required signals.
2. Submission of the log sheet which indicates the instants of each test starting and ending, is an essential component for the assessment quality.
3. The preferred time format is "DD-MM-YYYY HH:MM:SS.000".
4. Proper measuring units preferably "MW, MVAr, KV".
5. Proper terminology of the measured quantities, and files formatting.

D.2. Sampling rates:

Clauses ECC.6.6.3.1 and ECC.6.6.3.2 specify the required sampling rates for signals that must be provided by the User to the Company for onsite monitoring. These signals must adhere to the specified resolution unless an alternative agreement is made with the Company.

A. 1 Hz for reactive range tests (i.e., increments of 1 sec)
B. 10 Hz for frequency control tests (i.e., increments of 0.1sec (100msec))
C. 100 Hz for voltage control tests (i.e., increments of 0.01sec (10msec))

D.3. Compliance Test Log sheet & information provided at the beginning of each test:

Where test results are completed without any NESO 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.

ECP.A.4.3.8.1 lists the items to be included in the log sheet, users are always encouraged to provide the full list of signals listed in ECP.A.4.3.8.1 however as a minimum, the items below are mandatory for tests assessment:

1. Date and Time of the test.
2. Name of Power Station and PPM if applicable.
3. Name of Test engineer(s) and company name.
4. Name of Customer(s) representative and company name.
5. Type of testing being undertaken e.g. Voltage Control.
6. Ambient Conditions e.g. Temperature
7. Number of Units in service in each PPM, PGM.
8. Site registered capacity.
9. Controller settings, e.g. voltage slope, frequency droop, voltage setpoint.

D.4. The signals to be provided during and at the beginning of each test:

Clause ECP.A.4.3.8.2 mandates the customer to record a set of items, at the point of compliance, at the start of each test as relevant to the type of test being undertaken as indicated below:

- **ECP.A.4.3.8.2.1** lists the items of Voltage Control Tests
- **ECP.A.4.3.8.2.2** lists the items of Reactive Power Capability Tests
- **ECP.A.4.3.8.2.3** lists the items of Frequency Response Capability Tests

In all cases users are always encouraged to provide the full list of signals as listed in the GC and as listed below, however as a minimum, the Injection Start time and Injection End time, are always mandatory for tests assessment. The preferred time format is "DD-MM-YYYY HH:MM:SS.000".

Table 22: Signals to be recorded at the beginning of each test

Voltage Control	Reactive Capability	Frequency Control
Start & end date & time of each test step (*)		
Active Power		
Number of Units in service in each PPM		
Reactive Power		System Frequency
Connection voltage		Droop settings
Terminal Voltage if applicable		For offshore connections: Offshore GEP Active Power.
Generator transformers tap position or grid transformer tap position, as applicable		----
For offshore connections: Offshore GEP voltage.		----
Voltage Control Setpoint	----	----
Voltage Control Slope,	-----	----
(*) Signal is mandatory for assessment		

Section ECP.A.4.3.7 and subsections ECP.A.4.3.7.3.1-3 list the quantities to be recorded during different types of tests. Where these signals are provided to NESO it should be done in a consistent electronic format with a time stamp in a numerical format which can be interpreted in Excel format. Signals should be provided in the order and format presented below unless otherwise agreed, in advance, with NESO.

- Where any additional test signals to those indicated in the tables are presented, these should only be added with the agreement of NESO 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 NESO 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.

Users are always encouraged to provide the full list of signals as listed in ECP.A.4, however, the items below are mandatory for the test assessment:

Table 23: Signals to be recorded during each test

Voltage Control	Reactive Capability	Frequency Control
Date & Time		
Active Power		
Reactive Power		Speed /Frequency
STATCOM or Windfarm Reactive Power (if any)		Frequency Injection
Power Available / state of charge		
Voltage Setpoint	----	----
Connection Point Voltage	----	----
Reactive power setpoint (if any)	----	----

D.5. Format of the raw data files submission:

Raw test data templates:

To benefit both customers and NESO, NESO has created Excel templates for each type of test. These templates are available on the NESO website, links can also be found in **Appendix I: Important Links**: where customers can download an editable version and fill in their test results.

Table 24: Files Templates

Test	Template
Voltage Control Tests	Voltage Control Template.
Reactive Capability Tests	Reactive Capability Template.
Frequency Response Tests	1. Frequency Response Template MLP1 2. Frequency Response Template MLP2 3. Frequency Response Template MLP3 4. Frequency Response Template MLP4 number tests 5. Frequency Response Template MLP4 letter tests 6. Frequency Response Template MLP5 7. Frequency Response Template MLP6 8. Frequency Response Template Test L 9. Frequency Response Template Test N 10. Frequency Response Template Test M

Each template file contains three:

- Instructions Tab: For user instructions
- Results: For recording the test results and signals captured during the test,
- Log Sheet: For documenting the signals recorded at the start of each individual test,

Voltage step tests:

The voltage test results must be submitted in a single Excel worksheet, containing all tests in sequence (+1%, -1%, +2%, -2%, +4%, -4%) as shown in the figures below. For ESMs, a separate file should be provided for each mode of operation (export, import).

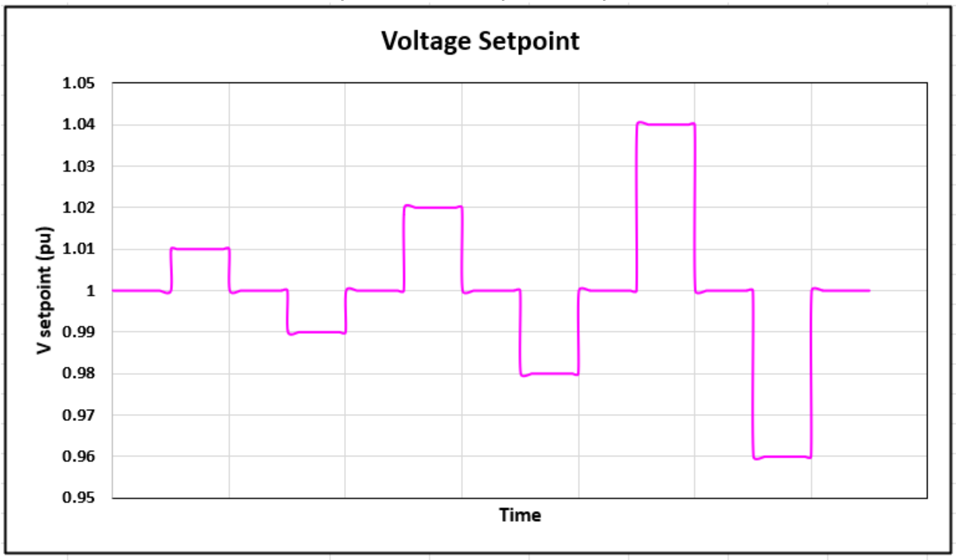


Figure 43: Voltage tests example

Frequency tests:

The frequency test results must be submitted such that all tests under the same MLP are submitted in a single Excel worksheet (except MLP4 and tests L, M, and N) as follows:

- MLP1 tests in separate Excel file
- MLP2 tests in separate Excel file
- MLP3 tests in separate Excel file
- MLP4 letter tests (except tests M and N) in separate Excel file.
- MLP4 number tests in separate Excel file.
- MLP5 tests in separate Excel file
- MLP6 tests (except test L) in separate Excel file
- Tests L, M, and N must be submitted each in a separate Excel file.

This results in a total of 10 separate files. For BESS, there will be 20 files in total.

Each file must include all tests under the same MLP in sequence, as illustrated in the pictures below:

- The file for MLP1 should contain tests (23-24-25-26-K) in sequence.
- The file for MLP3 should include tests (15-16-17) in sequence.

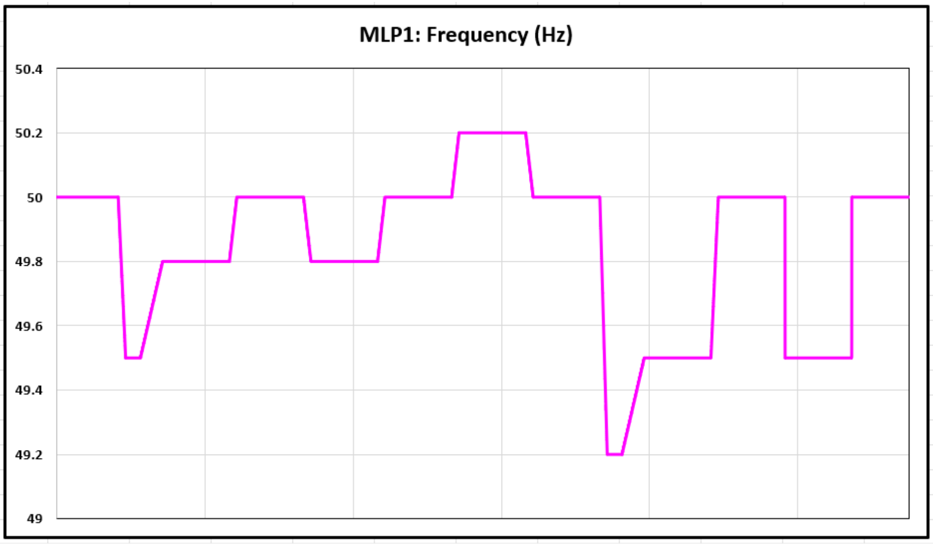


Figure 44: MLP1 Frequency tests example

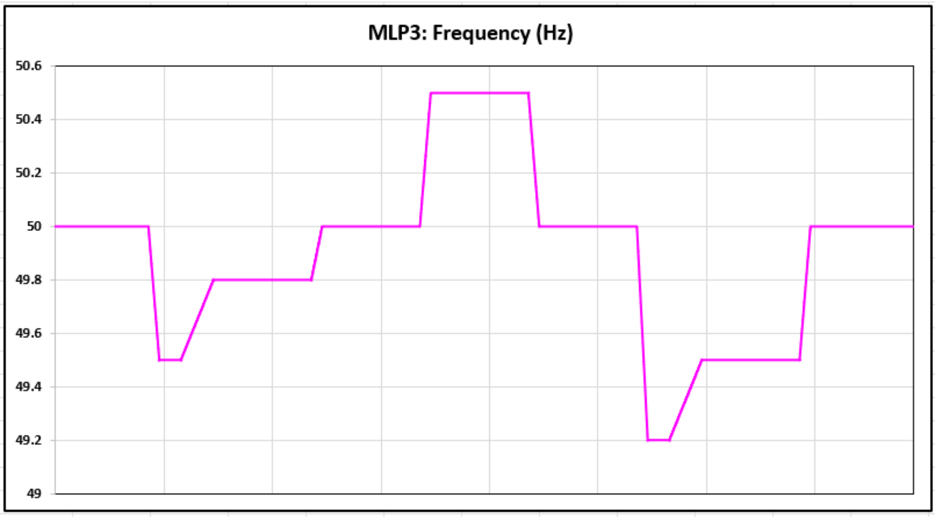


Figure 45: MLP3 Frequency tests example

Reactive Capability tests:

All the reactive capability test results must be submitted **in a single Excel worksheet**, containing all tests in sequence and with the same order described in **ECP.A.6.4.5** even for electricity storage modules.

De-load function tests:

The de-load function test results must be submitted **each in a separate Excel file** as follows:

1. Test 1: 49Hz, 100% import in separate file.
2. Test 2: 49Hz, 40% import in separate file.
3. Test 3: 48.8Hz, 100% import in separate file.
4. Test 4: 48.8Hz, 40% import in separate file.

D.6. Future Development of Compliance Testing

NESO 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:

- A suitable interface which allows NESO a view of the key test parameters graphically in real-time from the NESO office in Warwick. This would effectively provide the view of tests currently achieved by NESO connecting its recording equipment while at site.
- Where NESO 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 NESO in the standard format set out in the guidance note complete with an appropriate test log sheet.
- Where NESO has decided that the design of Power Park Units and apparatus is standardised, and the compliance can be evidenced by reference to a generic set of tests completed and accepted previously. This could be reference to Equipment Certificates where these have been accepted by NESO. This process will be offered provided in NESO’s opinion it does not pose a material risk in terms of the specific site installations.

NESO 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 NESO using the details in this guidance note.

D.7. NESO Data Recording Equipment

NESO will provide a digital recording instrument on site during the tests witnessed by NESO. A generic list of signals to be monitored during NESO 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 User should provide his 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 Generator is responsible for providing the listed signals to the User's and NESO's recording equipment. For NESO 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 NESO equipment is in the region of 1MOhm and its loading effect on the signal sources should be negligible.

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

Table 25: Typical Test Signal Schedule

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			

It may be appropriate for NESO 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 46: Example of Compliance Test Signal Connections.

At sites where there are multiple PPMs it may be advantageous for the developer to cable the signals for several PPMs to a single point. Where possible the person initiating the test injection signal (usually the manufacturer), the test co-ordinator (usually the owner) and NESO monitoring signals should be in the same room to minimise co-ordination issues during witness testing.

The PPM developer must inform NESO 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 PPM, 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 PPM 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:

- Total MW
- Total MVAr
- Point of connection line-line Voltage (HV) (kV)
- System frequency (Hz)

Appendix E: Other Technical Information

E.1. 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 PPMs and Power Park Units together with settings and time delays, including:

Table 26: Minimum Protection Requirements

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

E.2. Islanding Protection

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

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

E.3. Power Quality Requirements

For PPMs 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 User in coordination with the Transmission Owner is required to meet the relevant terms of the Grid Code. For more information about the Power Quality requirements, please refer to the relevant TO's Power Quality Monitoring team.

E.4. 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 Super-grid. This method relies on substituting the network between the Super-grid 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 Super-grid. 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 Super-grid, the technique described below is still appropriate however the equivalent impedance (described above) is removed.

E.5. Positive Sequence Studies

The simplified positive sequence network below will generally be accepted as satisfying the Positive Phase Sequence (PPS) aspect of studies in Grid Code ECP.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 Power Park Unit at a node selected by the manufacturer. The impedance between the point of connection and the 'type validation node' must reflect the equivalent aggregated impedance of the PPM 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.

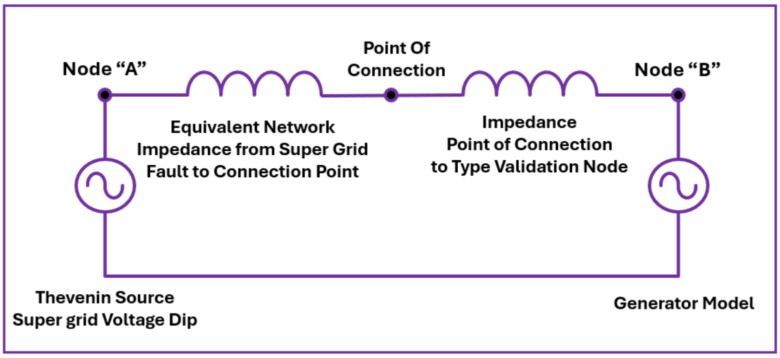


Figure 47: Simplified Positive Phase Sequence Network

This simplified network can be implemented in a power system analysis package of the Developer's 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'.

E.6. Negative Sequence Studies

Similarly, the simplified negative sequence network below will generally be accepted as satisfying the Negative Phase Sequency (NPS) aspect of Grid Code ECP.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.

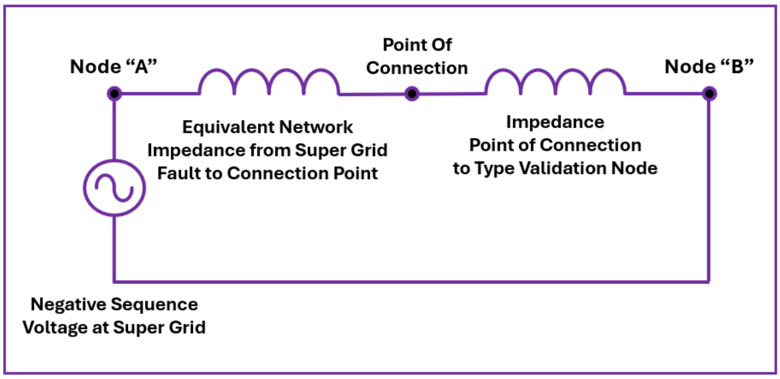


Figure 48: Simplified Negative Phase Sequence Network

Solving the load flow for the above network using a voltage source corresponding to the negative sequence magnitude at the Super-grid 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.

E.7. Technical Information on the Connection Bus Bar

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

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

Equivalent Circuit between Super-grid Busbar and PPM Point of Connection (showing transformer vector groups): [Assume system (NPS) impedance pre-and post-fault such that ECC.6.1.6 limits met]

E.8. Equivalent Sequence Impedances for Calculating Unbalanced Short- Circuit Current Contribution

The generator is required to provide the fault infeed from the PPM 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 PPM 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:

- **$Z1 = Z2 = 14.580\angle 88.091°$** **% on a 100 MVA base**
- **$Z0 = 159.1\angle 26.565°$** **% 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∠84.289°** **% on a 100 MVA base**
- **Z0 = 1.460∠84.289°** **% 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∠85.236°** **% on a 100 MVA base**
- **Z0 = 1.120∠85.236°** **% 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∠85.914°** **% on a 100 MVA base**
- **Z0 = 0.516∠85.914°** **% 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 35k

Appendix F: Response to Frequency Changes and Intermittent Power Source Variation

F.1. Scope

This Appendix is intended to provide guidance for manufacturers on the how control systems should react to changes in system frequency with fluctuations in the intermittent power source, with reference to **Power Park Module Signal Best Practice Guide** on the company website. This includes operation in both Frequency Sensitive and Limited Frequency Sensitive Modes.

Please note that this is just a guide and manufacturers are free to have their own designs and techniques to achieve the same effect on the system.

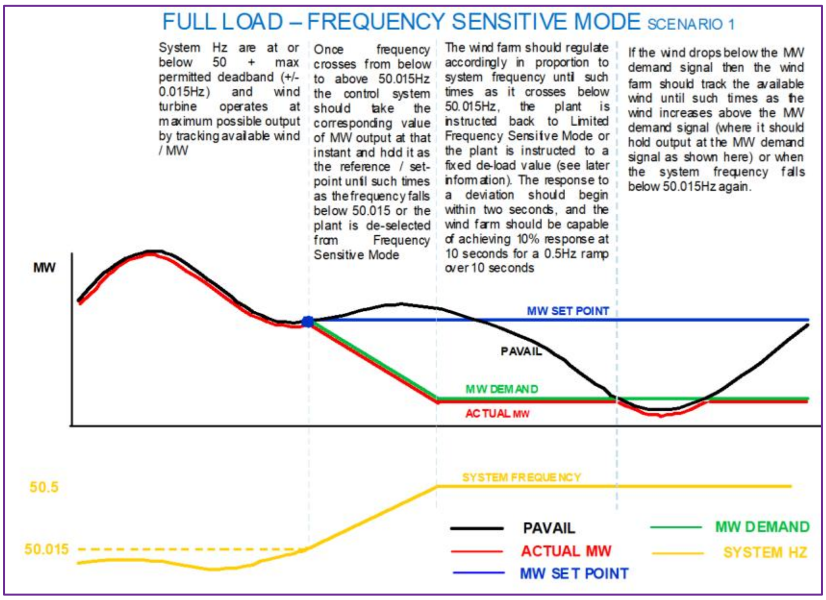
Several scenarios (high and low system frequency and various wind variations) are covered for each of four different operating points, to help explain how the response should be provided.

The four different operating points considered are

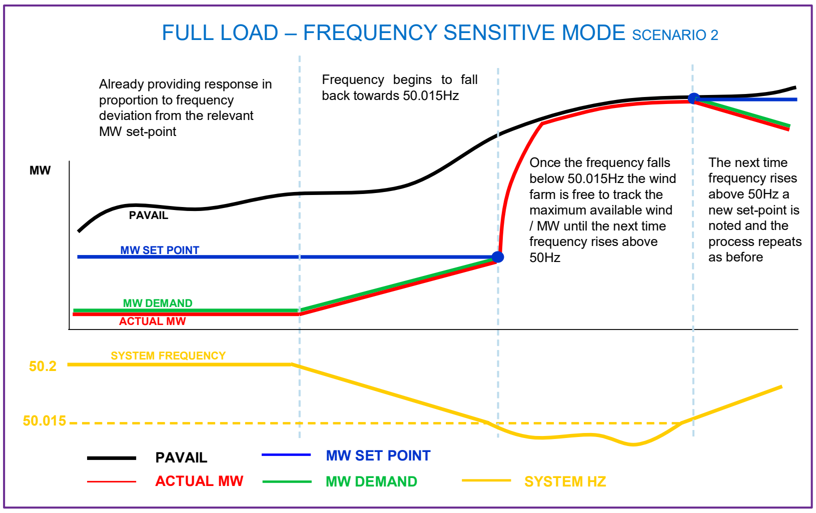
1) Frequency Sensitive Mode at full available MW / wind (high frequency response only)
2) Frequency Sensitive Mode at a de-load value below maximum available MW / wind
3) Limited Frequency Sensitive Mode at full available MW / wind
4) Limited Frequency Sensitive Mode at a de-load value below maximum available MW / wind

F.2. Frequency Sensitive Mode at Full Load:

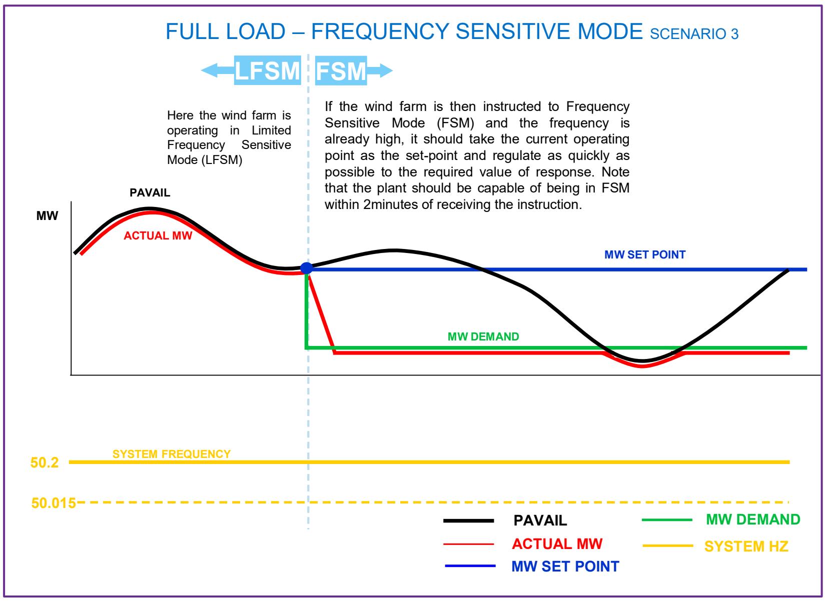
Scenario 1 – Start of a high frequency event followed by a drop in wind speed / available power.



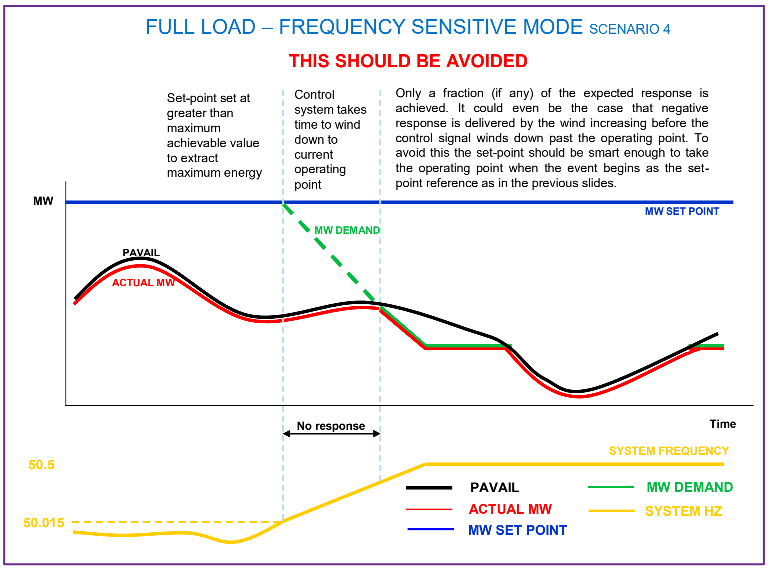
Scenario 2 – End of a high frequency event followed by another high frequency event.



Scenario 3 – Instructed to Frequency Sensitive Mode (from Limited Frequency Sensitive Mode) while system frequency is already high.



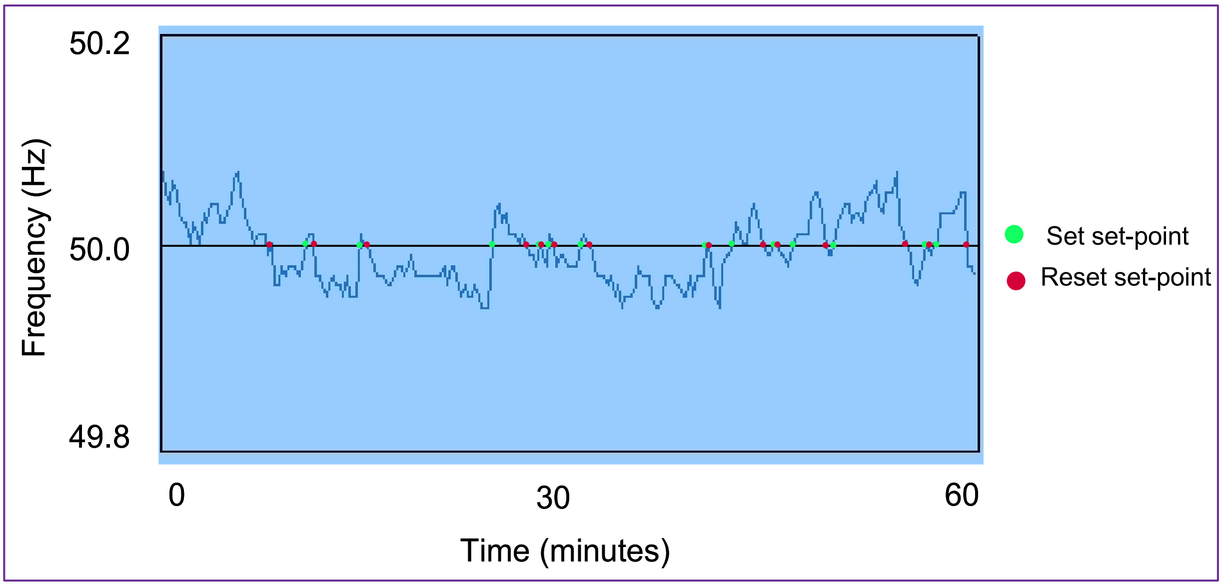
Scenario 4 – The case to avoid



F.3. Set and Re-set Set-point:

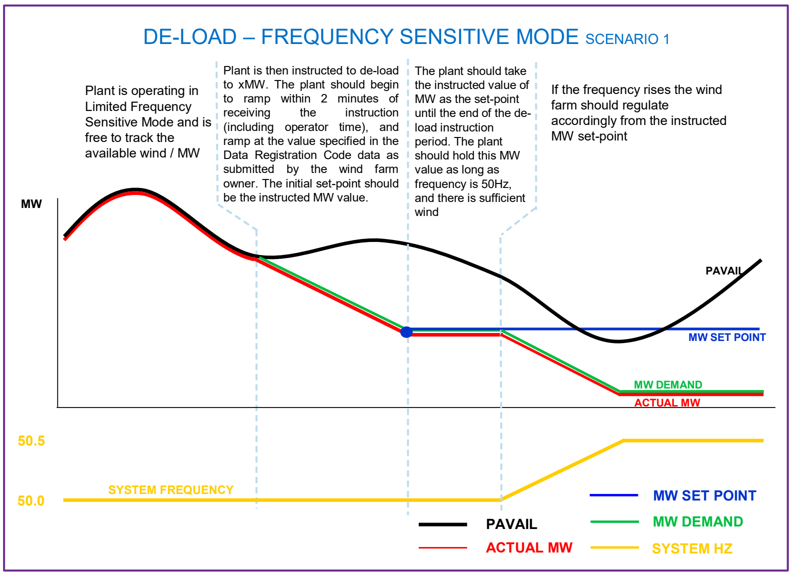
In order to provide consistent and sustainable response to high frequency the control system has to select the power park module output as a reference when the system frequency goes above 50Hz and release the reference when system frequency goes below 50Hz. The example below illustrates when to set and re-set the set-point using a real system frequency trace.

The green dots indicate where the system frequency passes from below 50Hz to above 50Hz. At this point the Power Park Modules control system should take and hold the corresponding MW output value at that instant as the Power Park Modules set-point. The Power Park Modules should then regulate in relation (wind conditions permitting) to that set-point until such times as the frequency falls below 50Hz (red dots), the unit is instructed back into Limited Frequency Sensitive Mode or the unit is instructed to a new de-loaded level

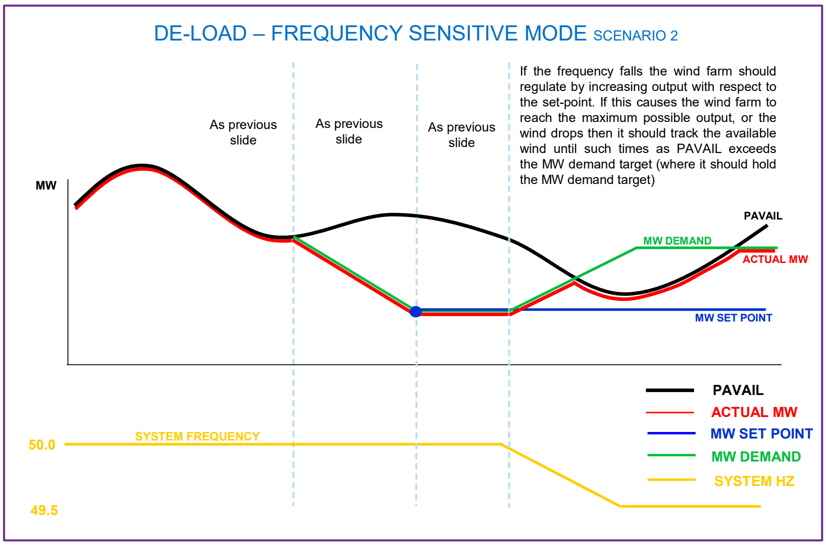


F.4. Frequency Sensitive Mode at De-Load:

Scenario 1 – Increase in system frequency after instructed to de-load

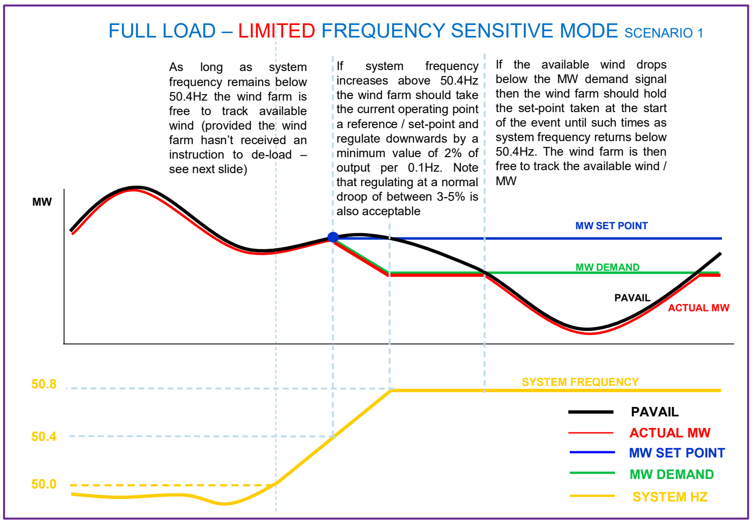


Scenario 2 – Decrease in system frequency after instructed to de-load

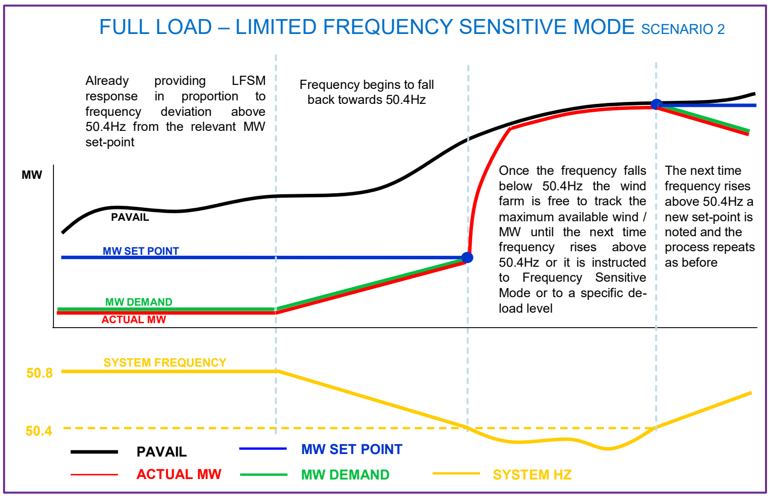


F.5. Limited Frequency Sensitive Mode:

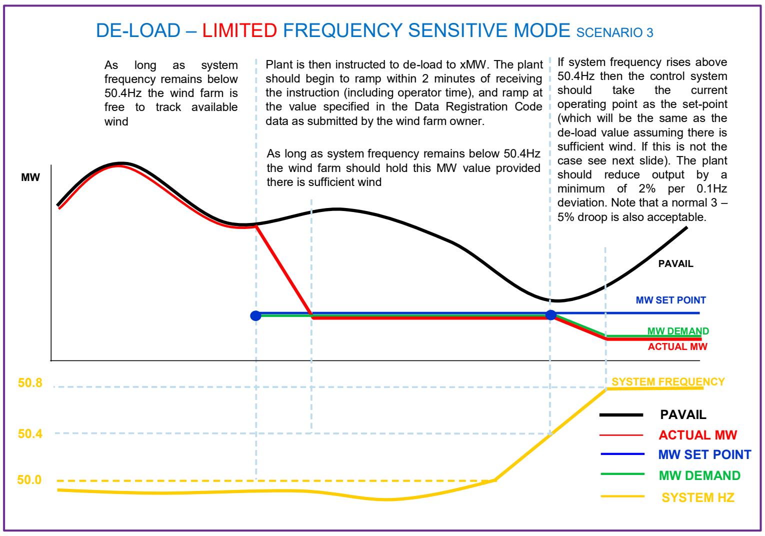
Scenario 1 – Limited Frequency Sensitive Mode from full load (frequency rising above 50.4Hz)



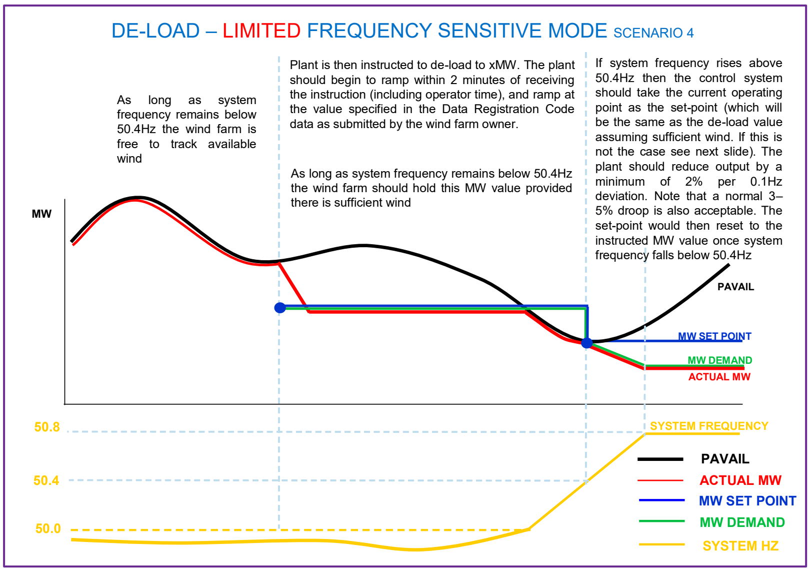
Scenario 2 – Limited Frequency Sensitive Mode from full load (frequency falling below 50.4Hz)



Scenario 3 – Limited Frequency Sensitive Mode from de-load position



Scenario 4 – Limited Frequency Sensitive Mode from de-load position with a drop in available wind / MW



F.6. Summary:

When de-loaded in GB the Power Park Module is instructed to a set MW value rather than a delta MW value from available MW (PAVAIL). While this may cause variability in the headroom for frequency response it allows the system to be balanced in an effective manner when large amounts of wind generation are connected (known as system balancing rather than frequency response). For Frequency Sensitive Mode at full load the Power Park Modules should take and hold the operating point (MW value) at the instance the system frequency crosses from below 50.015 to above 50.015Hz as the set-point.

Limited Frequency Sensitive Mode is required to be in operation at all times unless instructed to frequency sensitive mode. The Power Park Modules should take and hold the operating point (MW value) at the instance the system frequency crosses from below 50.4 to above 50.4Hz as the set-point. For Frequency Sensitive Mode at a de-loaded value the Power Park Modules should take the instructed MW value as the set-point.

The guidance here applies to the behaviour of the complete Power Park Modules. If frequency controllers are implemented on individual turbines, then variations to the suggestions here may have to be made to achieve the desired aims at the point of connection. Generator is still required to submit Final Physical Notification (FPN) and Maximum Export Limit (MEL) data as normal. The MEL figure submitted to NESO should be updated each time it differs from the available power by the greater of 5MW or 5% to ensure that the volume of available response can be correctly calculated. Not providing the expected response to a frequency deviation may cause premature limits on the amount of wind turbine plant that the system can cope with without detrimental effects on frequency stability. It is therefore essential that the response provided should be repeatable (wind conditions permitting).

Appendix G: Manufacturer's Data and Performance Report (MDPR) Process:

Manufacturers are concerned with protecting their innovations and technologies employed in Power Park Units which if shared could compromise their competitive advantage. In order to facilitate the market, the power industry has agreed that some information can be supplied directly to NESO from Power Park Units manufacturers. The Grid Code (ECP.11) explains that NESO may receive manufacturer information and Generators can reference it as part of their compliance demonstration.

Generators should note that using registered manufacturer data does not guarantee Grid Code compliance for a Power Park Module but does indicate that the Power Park Unit is capable of achieving Grid Code compliance in the appropriate area. Any Generator wishing to use manufacturer data is advised to contact NESO early in the compliance process to determine if the information held in the Register of Manufacturer's Data & Performance Report is appropriate and sufficient in each case. This approach can be used for information relating to the dynamic model of a single turbine unit, Inverters or park controller and the data and model validation reports associated with fault ride through type or Factory Acceptance tests.

While developers or Users may not see the Manufacturer's Data & Performance Report information, they must ensure that the correct reference is used as the same provisions as a normal Data Registration Code or a User Data File Structure submission will apply to this data. The Manufacturer's Data & Performance Report reference given by the Power Park Unit manufacturer will contain the following:

- ✓ Manufacturer name.
- ✓ Power Park or Inverter Unit type/Model/Class.
- ✓ Date of test
- ✓ The relevant report version number.
- ✓ The MDPR reference number for the relevant turbine/inverter

The User should then reference the document in the appropriate place in the User Data File Structure or DRC portal. For example, in case of fault ride through studies, assuming suitable fault ride through information is available in a Manufacturers Data and Performance report, the User can enter the following sentence;

"This information has been submitted generically to NESO and can be found in the NESO Register of Manufacturer's Data & Performance Report under document reference "manufacturerX_10MWturbinetype1_22Aug08_reportver001"

Appendix H: Grid Code Compliance Simulations Checklists

Disclaimer:

To achieve clarity and consistency in the compliance assessment of simulation studies, NESO has outlined the Grid Code compliance requirements in the form of simplified checklists against which their submission shall be assessed. With the required list of simulation cases, along with their performance acceptance criterion clearly defined, NESO endeavours to help the User self-assess their submissions to reduce the number of iterations of their simulation reports in the compliance stage.

These checklists have been prepared by consulting with the industry members on the Grid Code Development Forum and by incorporating the feedback received. Please note the checklists provided here are for guidance purposes only, and Customers are encouraged to use it. It is, however, not a mandatory requirement for the Customers to fill in and submit these checklists during compliance.

Project Name / Report Name:		Submission Date:	
Compliance Engineer:		Review Date:	

H.1. Voltage Control Studies Checklist

The User shall provide a report to demonstrate the dynamic capability and control stability of the PPM capturing results of below simulations. The purpose of this checklist is to help the User to submit the Grid Code compliant simulation studies. In any circumstances, the User must adhere to the Grid Code requirements in ECC.6.3.2, ECC.6.3.8, ECC.A.7 and ECP.A.3.4 as applicable.

Items	#	Functions / Documents checklist	GC reference	Compliant /Comment
Initial Conditions	1	The fault level at the HV connection point should be set at the minimum level.	ECP.A.3.4.2	
	2	Studies should be completed with a network operating at the voltage applicable for zero Reactive Power transfer at the Grid Entry Point (GEP)	ECP.A.3.4.2	
	3	Studies should be completed with the Power Park Module (PPM) is working at rated MW.	ECP.A.3.4.1(i) - (v)	
	4	The PPC should be in voltage control mode at onshore Grid Entry Point or Transmission Interface Point (In case of Offshore Power Park Module, the control mode of WTG will be subject to the control configuration of Offshore PPM)	ECP.A.3.4	
	5	The signals for simulation plots shall include but not limited to the voltage in per unit, active power in MW, reactive power in MVAr monitored at GEP (and/or TIP in case of Offshore Connection as applicable). Voltage controller reference signal in per unit shall also be included for relevant study cases.	Best Practice	
Complete List of Simulations	1	Confirm Completeness of the following simulations: 1. **ECP.A.3.4.1(i): Large (-ve) step in system voltage makes transition from Q=zero to Q= max lagging.** 2. **ECP.A.3.4.1(ii): Large (+ve) step in system voltage makes transition from Q=zero to Q= max leading.** 3. **ECP.A.3.4.1(iii): (-2%) voltage step while within 5% of Qmax lagging.** 4. **ECP.A.3.4.1(iv): (+2%) voltage step while within 5% of Qmax leading.**	ECP.A.3.4.1 ECP.A.3.7	

		5. **ECP.A.3.4.1(v): Large (-ve) step in system voltage transition from Q = max leading to Q = max lagging.** 6. **ECP.A.3.7.4: Voltage control Validation, step (2%) in the voltage reference.**		
	2	Confirm repeating the simulations mentioned above in import mode of operation (if BESS).	ECC.6.3.1	
During & Post Event	1	Confirm that the PPM remains transiently stable throughout the event.		
	2	The Slope characteristic of the continuously acting automatic control system shall be adjustable over the range 2% to 7% (with a resolution of 0.5%). The initial Slope setting should be 4%. An alternative slope setting may also be agreed with The Company for example, where requested by the relevant DNO in case of an Embedded User.	ECC.A.7.2.2.3	
	3	Droop settings used for the purposes of simulations shall be consistent and reflected in the submitted RMS and EMT models and the onsite testing.	PC.A.9.7	
	4	The reactive power output response of the PPM shall commence within 0.2 seconds of the application of the step.	ECC.A.7.2.3.1(i)	
	5	The reactive power output response shall progress linearly and smoothly although variations from a linear characteristic shall be acceptable provided that the MVAr seconds delivered at any time up to 1 second are at least those that would result from the response shown in figure ECC.A.7.2.3.1a.	ECC.A.7.2.3.1(i)	
	6	Confirm that 90% of the change in the reactive power output is achieved within: - (1 second), if transition is from zero to max lead or lag. - (2 seconds), if transition is from max lead to max lag or vice versa	ECC.A.7.2.3.1(ii)	
	7	The magnitude of the reactive power output response produced within 1 second shall vary linearly in proportion to the magnitude of the step change.	ECC.A.7.2.3.1(iii)	
	8	Within 5 seconds from achieving 90% of the response as defined in ECC.A.7.2.3.1 (ii), the peak-to-peak magnitude of any oscillations shall be less than 5% of the change in steady state maximum Reactive Power.	ECC.A.7.2.3.1(iv)	

H.2. FRT Studies Checklist

The User shall provide a report to demonstrate the dynamic capability and control stability of the PPM capturing results of below simulations. The purpose of this checklist is to help the User to submit the Grid Code compliant simulation studies. In any circumstances, the User must adhere to the Grid Code requirements in ECC.6.3.15, ECC.6.3.16, ECC.A.4, and ECP.A.3.5 as applicable.

Items	#	Functions / Documents checklist	GC reference	Compliant /Comment
General Requirements/Initial Conditions	1	The Power Park Module (or OTSDUW in case of Offshore Connection) should be in Voltage Control mode by default and the pre-fault conditions for reactive power should be achieved by tuning of system voltage and/or reference voltage of the controller. In case of Offshore Power Park Module, the initial conditions shall be dependent on design.	ECC.6.3.16.1.7	
	2	The retained voltages should apply to the faulted phases in case of unsymmetrical faults.	ECP.A.3.5.1(ii)	
	3	A three-phase fault means three phase to ground fault.		
	4	There shall be a smooth transition between voltage control mode and fault ride through mode in order to prevent the risk of instability which could arise.	ECC.6.3.16.1.7	
	5	In all the scenarios, the minimum fault conditions at the Supergrid HV Connection Point should be used (applicable for directly connected plants where connection point is at Supergrid level).	ECP.A.3.5.1(i):(v)	
	6	Where the Generator is Embedded or the Connection Point voltage is not at the Supergrid level, the minimum system impedance to the Supergrid shall be used which can be calculated from the maximum fault level at the Point of Connection. Please refer to the applicable NESO Guidance Notes Appendix section for detailed explanation.	ECP.A.3.5.1(iii):(v)	
	7	The FFCI requirements are applicable for all the balanced three phase faults including the voltage dips due to Supergrid faults.	ECC.6.3.16.1.2	
	8	For all balanced/unbalanced faults, User to confirm the relevant TOV requirements were met (Note: compliance with individual TOV technical requirements is outside the scope of this checklist)	ECC.6.3.16.1.14 ECC.6.3.16.1.6	
	9	The signals for simulation plots shall include but not limited to voltage in per unit, active power in MW, reactive power in MVAr, and reactive current (in both kA and per unit is recommended) monitored at GEP (and/or TIP in case of Offshore Connection as applicable).	Best Practice	

	10	In case of Onshore PPM confirm that short duration faults (up to 140msec) were performed at the GEP.	ECP.A.3.5.1(i), (ii)	
	11	In case of Offshore PPMs, confirm that the short duration faults (up to 140ms) were performed both at the offshore GEP and at the onshore Transmission Interface Point	ECP.A.3.5.1(i), (ii)	
	12	Confirm completing the short duration fault simulations when operating at Rated MW output and maximum leading Power Factor.	ECP.A.3.5.1	
	13	Confirm that longer duration faults (longer than 140msec) were performed at the nearest supergrid point.	ECC.6.3.15.8(i) ECP.A.3.5.1(iii), (iv)	
	14	Confirm completing the long duration fault simulations with the PPM operating at full Active Power and zero Reactive Power output.	ECP.A.3.5.1	
Complete List of Simulations	1	Confirm Completeness of the following simulations with correct retained voltage and correct timing: **Simulation (1): ECP.A.3.5(i): 3PHG fault, T=140 msec** **Simulation (2): ECP.A.3.5(ii): L-L fault, T=140 msec** **Simulation (3): ECP.A.3.5(ii): LLG fault, T=140 msec** **Simulation (4): ECP.A.3.5(ii): SLG fault, T=140 msec**	ECP.A.3.5	
	2	Confirm Completeness of the following simulations (>140ms) applied at nearest Super-grid (SG) substation: **Simulation (5): ECP.A.3.5(iii): 3PHG fault, Uret1, T1** **Simulation (6): ECP.A.3.5(iii): 3PHG fault, Uret2, T2** **Simulation (7): ECP.A.3.5(iii): 3PHG fault, Uret3, T3** **Simulation (8): ECP.A.3.5(iii): 3PHG fault, Uret4, T4** For Power Park Modules, the applicable retained voltage and withstand durations can be found in ECP.A.3.5	ECP.A.3.5	
	3	Confirm repeating the simulations mentioned above in import mode of operation (if BESS).	ECC.6.3.1	
	4	Confirm repeating the simulations mentioned above at 50% Max Capacity (if TEC>100MW).	ECP.A.3.5.4	
	5	Confirm repeating the studies to demonstrate the compliance during foreseeable running arrangements resulting from outages of major Plant and Apparatus.	ECP.A.3.5.3	
During and after the Fault	1	Confirm remain connected and stable for any balanced and unbalanced fault.	ECC.6.3.15.1.2	
	2	For any balanced fault which results in the positive phase sequence voltage falling below the voltage levels specified in ECC.6.1.4 at the Grid Entry Point or User System Entry Point (USEP), the Generator shall inject a reactive current above the heavy black line shown in Figure ECC.16.3.16(a) at GEP	ECC.6.3.16.1.2	

	3	FFCI should as a minimum increase with the fall in the retained voltage each time the voltage at the GEP or USEP falls below 0.9pu whilst ensuring the overall rating of the Power Park Module shall not be exceeded.	ECC.6.3.16.1.3 Figure ECC.6.3.16(a)	
	4	FFCI should be above the shaded area shown in Figure ECC.6.3.16(b) and Figure ECC.6.3.16(c) which illustrate how the reactive current shall be injected over time.	Figure ECC.6.3.16(b) Figure ECC.6.3.16(c)	
	5	The post fault voltage shall not be less than 0.9pu.	ECC.6.3.15.8(iii)	
	6	Confirm within 0.5 seconds following fault clearance at the GEP or USEP to 90% of nominal voltage or greater (or within 1 second for long duration faults as per ECC.6.3.15.9.2.1), the Power Park Module restore the Active Power output to at least 90% of the level available immediately before the fault. Once the Active Power output has been restored to the required level, Active Power oscillations shall be acceptable provided that: à the total Active Energy delivered during the period of the oscillations is at least that which would have been delivered if the Active Power was constant à the oscillations are adequately damped.	ECC.6.3.15.8(vii) ECC.6.3.15.9.2.1(a)(iii) ECC.6.3.15.9.2.1(b)(iii)	
	7	The reactive power change after the step change in the voltage shall be in accordance with ECC.A.7 requirement (i.e. 90% of the reactive power change after the step recovery in the voltage at the GEP shall be achieved within one second)	ECC.A.7.2	
	8	Confirm remain transiently stable and connected to the system without tripping and satisfy the requirements of ECC.6.3.16	ECC.6.3.15.1.2 ECC.6.3.15.9.2	

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H.3. Frequency Response Studies Checklist

The User shall provide a report to demonstrate the dynamic capability and control stability of the PPM capturing results of below simulations. The purpose of this checklist is to help the User to submit the Grid Code compliant simulation studies. In any circumstances, the User must adhere to the Grid Code requirements in ECC.6.3.7, ECC.A.3 and ECP.A.3.6 as applicable.

Items	#	Functions / Documents checklist	GC reference	Compliant /Comment
Complete list of simulations required for PPM				
		Confirm Completeness of the following simulations with correct procedure: Simulation (1): ECP.A.3.6.4: LR, FSM, Max Export Simulation (2): ECP.A.3.6.5: LR, LFSM, Max Export	ECP.A.3.6 ECP.A.3.6.1 - ECP.A.3.6.5	
	2.	**High Frequency Simulations: (signal application and removal in a step manner (0-1sec), signal hold for 90sec)**		
		Simulation (3): ECP.A.3.6.6, BC1 [Step test] (FSM), Max Export Simulation (4): ECP.A.3.6.6, BC3 [Step test] (LFSM), Max Export	ECP.A.3.6.6	
	3.	**ECP.A.3.6.8: Under-frequency Simulation – (LFSM-U)**		
		Simulation (5) ECP.A.3.6.8_Export_LFSM	ECP.A.3.6.8	
	4.	**ECP.A.3.7.2: Model Validation Simulations**		
		Simulation (6): ECP.A.3.7.2: Frequency Profile validation	ECP.A.3.7.2	
		In addition to the aforementioned simulations, an Electricity Storage Module will be required to complete following list of simulations		
	5.	**ECP.A.3.6.7: Load rejection Simulations**		
		Confirm Completeness of the following simulations with correct procedure: Simulation (7): ECP.A.3.6.7(i): LR, FSM, Zero active power Simulation (8): ECP.A.3.6.7(i): LR, LFSM, Zero active power Simulation (9): ECP.A.3.6.7(ii): LR, FSM, 50% Import	ECP.A.3.6.7	

		Simulation (10): ECP.A.3.6.7(ii): LR, LFSM, 50% Import Simulation (11): ECP.A.3.6.7(iii): LR, FSM, Max Import Simulation (12): ECP.A.3.6.7(iii): LR, LFSM, Max Import		
	6.	**High Frequency Simulations for Electricity storage module: (signal application and removal in a step manner (0-1sec), signal hold for 90sec)**		
		Simulation (13): ECP.A.3.6.6, BC1 [Step test] (FSM), Max Import Simulation (14): ECP.A.3.6.6, BC3 [Step test] (LFSM), Max Import	**ECP.A.3.6.6**	
	7.	**ECP.A.3.7.2: Model Validation Simulations**		
		Simulation (15): ECP.A.3.7.2: Frequency Profile validation in import mode	**ECP.A.3.7.2**	
	8.	**ECP.A.3.6.(9-12): De-load function Simulations**		
		Simulation (16): Figure ECP.A.3.6.4: De-load, 49Hz, Max Import Simulation (17): Figure ECP.A.3.6.4: De-load, 49Hz, 40% Import Simulation (18): Figure ECP.A.3.6.5: De-load, 48.8Hz, Max Import Simulation (19): Figure ECP.A.3.6.5: De-load, 48.8Hz, 40% Import Simulation (20): Figure ECP.A.3.6.6: De-load, 48.3Hz, Max Import Simulation (21): Figure ECP.A.3.6.6: De-load, 48.3Hz, 50% Import	**Figure ECP.A.3.6.4 - Figure ECP.A.3.6.6**	
General Requirements	1	Droop settings used for the purposes of simulations shall be consistent with submitted models and onsite testing. For example, if a 3% droop was selected for Frequency Sensitive Mode simulation studies, then the corresponding onsite tests and submitted models shall be reflective of this.	PC.A.9.7	
	2	The acceptable droop range for LFSM-O: between 2 to 10%, LFSM-U: below 10%, LFSM-U (import): 0.6 to 1.2%	ECC.6.3.7.1 and ECC.6.3.7.2	
	3	The acceptable droop range for FSM: between 3 to 5%.	ECC.6.3.7.3	
	4	In the case of over-frequency, the active power frequency response shall be limited by the Minimum Regulating Level (MRL)	ECC.6.3.7	
	5	In the case of underfrequency, the active power frequency response shall be limited by the Maximum Capacity	ECC.6.3.7	
	6	In the event of a Frequency step change, each Type C and Type D PGM/PPM shall be capable of activating full and stable Active Power Frequency response (without undue power oscillations).	ECC.6.3.7	
	7	The active power response shall initiate with minimum possible delay as per ECC.6.3.7 requirements		

	8	For all the Load Rejection scenarios: ♦ Please refer to the appropriate NESO Guidance Notes to follow the requirements of ECC.6.3.7 ♦ The PPM shall be operating at Max. Capacity before the breaker action and the frequency droop in accordance with LFSM and FSM requirements is deployed. The Load 1 and Load 2 in Figure ECP.A.3.6.2 shall be configured such that the PPM reduces its Active Power Output in accordance with the droop settings used ♦ The monitored signals shall be: System Frequency, PPM /PGM active power, and SPGM active power ♦ Where transient frequency excursions above 52Hz occur, the duration above 52Hz should be less than any high Frequency protection system	ECC.6.3.7.3.5	
	9	When operating in LFSM-O, comply with all the applicable requirements of the Grid Code	ECC.6.3.7.1	
	10	For all the LFSM-U simulation scenarios, comply with all the applicable requirements of the Grid Code	ECC.6.3.7.2	
	11	In case of Electricity Storage Modules demonstrating LFSM-U capability in Import mode: ♦ Fulfil the requirements of ECC.6.3.7.2.3 ♦ During a low frequency event, the Plant shall transition from Import to Export mode and demonstrate the performance described in ECC.6.3.7.2.3.2. Only when the energy storage is depleted (eg. insufficient State of Charge), and the Plant is unable to make the transition to export mode, it shall be required to operate at zero Active Power output. ♦ When the system frequency is recovered beyond 49.5Hz, the Plant is permitted to reduce its Active Power output such that it reaches the pre-event operating point. In some cases, this may mean the Plant transitions from Full Export to Full Import after the frequency is recovered in extremely fast manner. It is advisable for User to limit the ramp rate of such magnitude of Active Power change to at or below 0.2pu/s (during recovery) where NESO identifies a risk to system stability ♦ When the Plant is exporting the Active Power (including 0MW operation) and the system frequency drops below 49.5Hz, it shall operate normally as per LFSM-U export characteristic specified in ECC.6.3.7.2.1 and ECC.6.3.7.2.2		
	12	When operating in FSM, comply with all the applicable requirements of the Grid Code	ECC.6.3.7.3	

Appendix I: Important Links:

This section details the list of guidance documents published on **NESO Compliance Webpage** to provide further clarification around the compliance requirements and different sections of the compliance process.

- **The Grid Code | NESO**
- **Compliance Process | National Energy System Operator**
- **Introduction to the Compliance Process**
- **Grid Forming Guidance Note**
- **Compliance Repeat Plan - Guidance Notes**
- **Guidance Notes on Modelling Requirements – GC0141 Grid Code Modification**
- **Guidance Notes for Electro-Magnetic Transient (EMT) Models**
- **Integral Equipment Tests - Guidance Notes**
- **Guidance Notes for Co-location of Different Technologies**
- **Guidance on Oscillation Assessment for Inverter Based Resources (IBRs)**
- **Guidance for test results**
- **Grid Code Testing Templates Kit**

Appendix J: Contacting NESO

There are several different departments within NESO that will be involved with a connection during the compliance journey. The initial point of contact for NESO 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 the email below:

box.ecc.compliance@neso.energy

For any queries related to Engineering Compliance, please use the email address below:

box.ec.queries@neso.energy

For any correspondence relating to testing on the system, the IET process should be followed with notifications made to the NAP teams:

- **England and Wales: tranreq@neso.energy**
- **Scotland: trscotland@neso.energy**

Contact Address:

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

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Gallows Hill, Warwick, CV346DA
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