Guidance Notes –

Synchronous Generating Units

Issue 12
September 2012

Foreword

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

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

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

These Guidance Notes are based on the Grid Code, Issue 5, Revision 0, effective from the 17 August 2012. They have been developed from Issue 11 of the Guidance Note of September 2008 and reflect the major changes brought about by Grid Code revision A/10 as approved by the regulator on 26 July 2012.

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

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

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

Telephone: 01926 65 4601
Email: box.gdpsharedmailb@nationalgrid.com

Contents

Guidance Notes - Synchronous Generating Units

Abbreviations

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

Abbreviation	Description
AVC	Automatic Voltage Control (on transformers)
AVR	Automatic Voltage Regulator
BA / BCA	Bilateral Agreement / Bilateral Connection Agreement
BC	Balancing Code
BM / BMU	Balancing Mechanism / Balancing Mechanism Unit
CC / CC.A	Connection Conditions / Connection Conditions Appendix
CCGT	Combined Cycle Gas Turbine
CUSC	Connection and Use of System Code
DCS	Distributed Control System
DNO	Distribution Network Operator
DMOL	Design Minimum Operating Level
DPD	Detailed Planning Data
DRC	Data Registration Code
EDL/EDT	Electronic Data Logging / Electronic Data Transfer
ELEXON	Balancing and Settlement Code Company
FON	Final Operational Notification
FRT	Fault Ride Through
FSM	Frequency Sensitive Mode
GB	Great Britain
GCRP	Grid Code Review Panel
GT	Gas Turbine
ION	Interim Operational Notification
LSFM	Limited Frequency Sensitive Mode
LON	Limited Operational Notification
MEL	Maximum Export Limit
MLP	Machine Load Point
NGET	National Grid Electricity Transmission
OC	Operating Code
OCGT	Open Cycle Gas Turbine
OEL	Over Excitation Limiter
OFGEM	Office of Gas and Electricity Markets
PC	Planning Code
PSS	Power System Stabiliser
PSSE	Power System Analysis Software
RISSP	Record of Inter System Safety Precautions
SEL	Stable Export limit
SO	System Operator (National Grid)
SPT	Scottish Power Transmission
SHETL	Scottish Hydro Electric Transmission Limited
ST	Steam Turbine
STC	System Operator Transmission Owner Code
TO	Transmission Owner
TOGA	Transmission Outages, Generation Availability

UDFS	User Data File Structure
UEL	Under Excitation Limiter

Introduction

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

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

This particular edition of the guidance notes has been written for conventional synchronous generation technologies. A separate document exists for new generation technologies based on asynchronous plant referred to as power parks.

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

Compliance Process

The process for Generators to demonstrate compliance with the Grid Code and Bilateral Agreement is included in the Grid Code Compliance Processes (CP). In addition to the process and details of the documentation that is exchanged to control the process, an appendix to the Compliance Processes includes the technical details of the simulation studies that a Generator should carry out. The Compliance Processes cross reference with other sections of the Grid Code, namely the Planning Code (PC), the Connection Conditions (CC) and Operating Code 5 (OC5).

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

The CC set out the majority of the generic performance requirements that a Generator is required to meet with site specific variations laid out in the Bilateral Agreement.

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

Model

The Generator is required to provide National Grid and the Transmission Owner (for sites in Scotland) with a model of their generating unit as detailed in PC.A.5.3.2 (a to f) of the Grid Code. The model data is to be provided as Laplace transfer functions in a block diagram format. Control systems with a number of discrete states or logic elements may be provided in flow chart format if a block diagram format does not provide a suitable representation.

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

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

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

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

Simulation Studies

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

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

CP.A.3 outlines simulation studies that are required to verify compliance with Grid Code requirements. The simulations must be based on the models supplied to National Grid in accordance with Grid Code Planning Code Appendix section 5.3.2 (PC.A.5.3.2) except for the load rejection simulations in CP.A.3.6 where a more complex model may be utilised if appropriate provided a validation study as specified in CP.A.3.6.6 is also provided.

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

Compliance Tests

Tests identified in OC5.A.2 of the Grid Code are designed to demonstrate where possible that the relevant provisions of the Grid Code and Bilateral Agreement have been met. However if the test requirements described in OC5.A.2 are at variance with the Bilateral Agreement or the test requirements are not relevant to the plant type the Generator should contact National Grid to discuss and agree an alternative test program and success criteria.

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

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

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

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

National Grid Data Recording Equipment

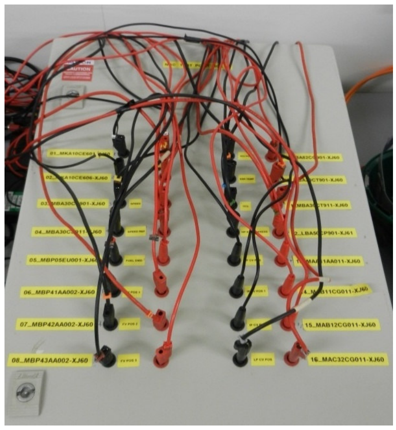
National Grid will provide a digital recording instrument on site during the tests witnessed by National Grid. A generic list of signals to be monitored during National Grid witnessed tests is tabulated in OC5.A.1.2. This will be used to monitor all plant signals at the sampling rates indicated in CC.6.2.2. The station should provide its own digital recording equipment to record the same plant variables. This will provide a back up to the test results should one of the recording instruments fail at the time of testing.

The station is responsible for providing the listed signals to the User's and National Grid's recording equipment. For National Grid purposes the signals provided are required to be in the form of dc voltages within the range -10V to +10V (see CC.6.2.2). The input impedance of the National Grid equipment is in the region of 1MOhm and its loading effect on the signal sources should be negligible.

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

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

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



Test Notification to Control Room

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

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

Model Validation

The results recorded during the compliance tests may be used to validate the model of the excitation control system and the frequency control system.

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

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

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

Simulation of the test under the test conditions should be carried out and the simulation results should be then compared with the test results. If the results are identical or matched very well then the submitted model has been validated and accepted as the accurate model of the plant. If the results are different then the Generator, or the Generators agent, i.e. consultant or equipment manufacturer, should resubmit a modified model. This process will be repeated until there is close agreement with the test results and simulation results.

Protection Requirements

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

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

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

Islanding Protection

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

Pole Slipping Protection

National Grid does not generally ask for Pole Slipping Protection to be fitted to Generating units connected to the transmission system. However, if it is proposed to fit Pole Slip Protection by a Generator, the settings should be agreed with National Grid to reduce the risk of mal operation during the clearance of faults on the transmission system. In general the "reach" of the protection should not exceed the impedance based on the generating unit and the worst case impedance of the generating unit step up transformer. Where any setting looks beyond the Generator and Transformer impedance the slip counter setting must be greater than 1.

Appendix A Reactive Capability

Summary of Requirements

The reactive capability requirements for a generating unit are set out in CC6.3.2 of the Grid Code, and for synchronous plant this establishes a power factor value which must be achievable at the Rated MW value of the generating unit both in terms of leading and lagging Mvars.

Where a generating unit can achieve active power output above the declared Rated MW the lagging capability must be in line with CC.6.3.2(a)(i) or CC.6.3.2(a)(ii). When operating at an active power output other than Rated MW the generating unit performance chart submitted under PC.A.3.2.2(f) indicates the capability of the generating unit.

In addition to the requirement in CC.6.3.2 the Grid Code CC6.3.4 also requires capability that a generating unit is able to deliver the CC.6.3.2 reactive capability across a variation in system voltage to which it is connected of +/-5%. This capability is typically achieved for a synchronous generator by the application of an on load tapchanger in the generating unit step-up transformer. The tapchanger being capable of on-load changes in tap position and having sufficient taps to satisfy the combined requirements of CC6.3.2 and CC.6.3.4.

The GB convention for Mvars is for lagging reactive power representing reactive power supplied by the generating unit into the network.

Reactive Capability Testing

In order to demonstrate that a synchronous generating unit can satisfy the reactive capability requirements it is necessary to perform reactive capability tests as set out in OC5.A.2.7.

Where active power in excess of Rated MW is declared on the performance chart in addition to tests at Rated MW, the reactive capability at maximum active power should also be demonstrated.

Reactive Capability tests are not normally witnessed by National Grid so where a Generator is recording the tests the following test procedure and schedule is provided.

Guidance Notes - Synchronous Generating Units

Test No	Step	Description	Notes
		Increase Active Power output to Rated MW	
		• Confirm AVR in control and PSS if fitted commissioned and in service • Confirm AVR Voltage Setpoint set to 1 per unit.	
1		• Active power output maintained at Rated MW • Generating unit transformer tapped to generate maximum continuous leading Reactive Power and hold for 60 minutes.	
2		• Active power output maintained at Rated MW • Generating unit transformer tapped to generate maximum continuous lagging Reactive Power and hold for 60 minutes.	
		If applicable increase Active Power output to maximum value on performance chart.	
		• Confirm AVR in control and PSS if fitted commissioned and in service • AVR Voltage Setpoint set to 1 per unit.	
3		• Active power output maintained at maximum MW • Generating unit transformer tapped to generate maximum continuous leading Reactive Power and hold for 60 minutes.	
4		• Active power output maintained at maximum MW • Generating unit transformer tapped to generate maximum continuous lagging Reactive Power and hold for 60 minutes.	

RECORD OF REACTIVE POWER MONITORING RESULTS

……………….……….POWER STATION

GENERATING UNIT/MODULE ………………………………………………………….

Date of Test ……………………………………. Approximate Ambient Temperature ………………..

Power Station Control Engineer …………………….. NGET Control Engineer……………………..

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

Generating Unit	Time	MW At Generator Terminals	MVAr Lead/Lag At Generator Terminals	Tap Position (if known)	HV Voltage

OBSERVATIONS & REMARKS

Appendix B Voltage Control and PSS Testing

Summary of Requirements

The requirements for voltage control are set out in a number of parts of the Grid Code with additional parameters specified by National Grid within the Bilateral Connection Agreement with the Generator. The relevant sections are CC.6.3.6(a), CC.6.3.8, CC.A.6. Within section CC.A.6 there are ranges indicated associated with positive and negative ceiling voltage, and voltage control rise time. The actual values of these relevant to a specific connection will be provided in the Agreement.

Open Circuit Tests

Prior to first synchronising a new generating unit (or one with a new excitation system) onto the system the Generator should perform open circuit testing as required by CP.6.4,. The details of the test are given in OC.5.A.2.2 and the results should be presented to National Grid in the form of graphs with legible axes and scaling plus the data in a form which can readily be imported into Excel. National Grid will indicate acceptance of the open circuit tests in writing whereupon the Generator provided there are no other active restrictions may synchronise the relevant generating unit.

Power System Stabiliser Commissioning and Testing

The industry codes (Grid Code, CUSC etc.) in general assume a generating unit is fully operational from the moment of connection. This is not practical as many systems will need on-load commissioning in order to ensure their correct operation. Some systems such as the power system stabiliser (PSS) have been identified as having significant potentially negative impacts on the security of the National Grid transmission system if incorrectly commissioned. The Grid Code BC.2.11 prohibits commissioning of the PSS unless National Grid is in attendance.

Where a power station consists of multiple generating units which have to be fitted with PSS an assessment of the risk associated with connection and commissioning of more than one generating unit simultaneously without the PSS in service will be made by National Grid. If the system risk is seen as significant a restriction on the maximum active power output, reactive power operating range or number of connected units may be placed within the ION until stabilisers have been commissioned successfully. The Generator will be informed of any such restrictions during the compliance process and ahead of the issue of the ION.

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

The suitability of the tuning of any PSS is checked in both the time and frequency domains. In the time domain testing is by small voltage step changes injected into the

AVR voltage reference block. Comparisons are made between performance with and without the PSS in service.

For analysis in the frequency domain, a bandwidth-limited (200mHz-3Hz) random noise injection should be made to the AVR 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 stability of the PSS gain setting will also be assessed by increasing the gain in stages to 3x the proposed setting. This increase is carried out gradually while monitoring the generator for any signs of instability.

The tests will be regarded as supporting compliance of the PSS 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 test demonstrates no appreciable instability at 3x proposed gain

An outline test procedure is provided in OC5.A.2.4.3 to assist Generators in drawing up their own site specific procedures for the National Grid witnessed PSS Tests although National Grid will be happy to consider an alternative test procedure suggested by the Generator.

Under Excitation Limiter (UEL) Testing

This test is carried out to establish the setting of the limiter and to verify its correct operation including adequate damping. If the excitation control system includes a PSS, tests should be carried out with PSS switched on.

As discussed earlier in this Appendix National Grid may impose operating limitations on a generating unit prior to completed the PSS commissioning tests. Under these circumstances a Generator may be unable to confirm the correct operation of an under excitation limiter at its true setting. However, a functional test at an operating point consistent with the restriction placed in the ION is possible and should be completed by the Generator. Prior to successful under excitation limiter testing it may be appropriate to apply temporary settings in order to reduce the risk of instability during the commissioning period. This should be discussed with the National Grid Compliance Engineer and agreed prior to issue of an ION.

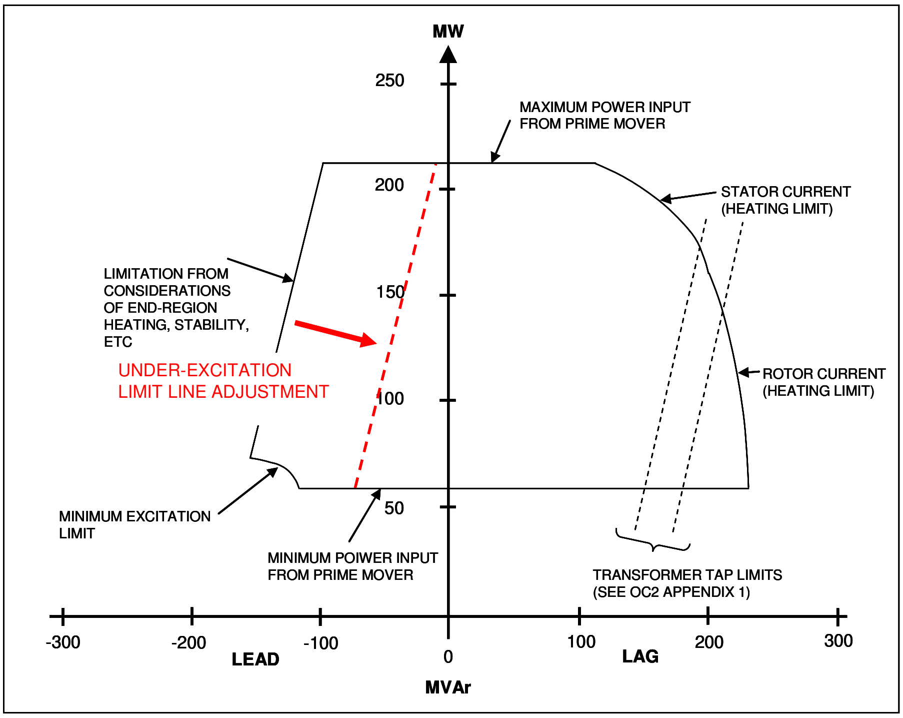


Figure B.1 Example of reducing UEL setting for functionality test

When the generator is operating near the UEL limit the stability margin is less than when it is operating at unity power factor. For safety a preliminary set of tests are specified below with the UEL limit moved towards unity power factor line. If the preliminary tests are successful then the UEL limit is moved to its design position and the tests are repeated.

The UEL action should be initiated by injecting a negative voltage step of -2% into the AVR voltage reference, with the generator initially operating near the UEL limit. The test procedure given below details the step injection method.

It may prove beneficial to perform an optional test with the PSS off, to understand the interaction between the PSS and limiter.

In addition it is also useful to demonstrate the UEL control action by tapping the generating unit transformer to move the output of the unit into the limiter.

An outline test procedure is provided in OC5.A.2.5.5 to assist Generators in drawing up their own site specific procedures for the National Grid witnessed PSS Tests although National Grid will be happy to consider an alternative test procedure suggested by the Generator.

Over Excitation Limiter (OEL) Testing

The action of an OEL differs from that of an UEL so the OEL test requirements are normally discussed with National Grid prior to testing in order to establish a sensible test procedure, appropriate to the control system design.

National Grid are particularly interested in ensuring the OEL is set as high as possible, whilst ensuring the machine design limits are not breached and that the machine protection will not operate before or whilst the OEL is active.

The OEL action is typically initiated by injecting a +2% to +10% positive voltage step into the AVR voltage reference. The OEL would normally be set at the maximum value within the design limit for the generating unit. Excitation at OEL setting is well above excitation at rated MVA. For this reason the test is not typically carried out at the OEL setting. For the test the OEL setting is typically reduced to a level equivalent to the maximum rated MVA position, i.e. rated MVA and maximum lagging MVAr. A positive step is then applied to the AVR Voltage reference or the generating unit step-up transformer is tapped to take the MVAr output higher. If the OEL is working correctly, the OEL should operate after sufficient time delay to bring back the excitation within limits.

The steady state accuracy of the limit level and any overshoot are of particular interest, as the Generator and National Grid may need to determine the limit level once the setting is restored and ensure that any protection does not operate.

If the OEL has multiple levels to account for heating effects, an explanation of this functionality will be necessary and if appropriate, a description of how this can be tested.

An outline test procedure is provided in OC5.A.2.6.3 to assist Generators in drawing up their own site specific procedures although National Grid will be happy to consider an alternative test procedure suggested by the Generator.

Appendix C Frequency Control

Summary of Requirements

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

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

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

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

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

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

The Grid Code Figure CC.A.3.1 specifies a minimum requirement for frequency response of 10% of Registered Capacity achievable for Primary Secondary and High Frequency response. This minimum value is designed to ensure that plant provides a suitable contribution to maintain frequency correction when connected to the system and selected to Frequency Sensitive Mode (FSM) and response capability in excess of 10% is encouraged.

The speed of response is an important criteria and the Grid Code Figures CC.A.3.2 and CC.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 National Grid accepts a delay of up to but not exceeding 2 seconds before measureable response is seen from a generating unit in response to a frequency deviation.

BC3 of the Grid Code specifies how plant should be operated and instructed to provide frequency response. The section also sets out the requirements on how all plant should respond to the system frequency rising above 50.4/50.5Hz, by progressively reducing output power.

Details of the tests required for the preliminary and main governor response tests are provided in OC5.A.2.8 but additional guidance is provided in this Appendix including outline test procedures.

Modes of Frequency Control Operation

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

Limited Frequency Sensitive Mode is used when not instructed by National Grid to provide Frequency Response Services. In this mode the Power Park Module is not required to provide any increase in active power output if frequency reduces below 50Hz and is only required to maintain active power output in accordance with CC.6.3.3. However, the Power Park Module is required to respond to high frequencies above 50.4Hz beyond which the Module must reduce the active power output by a minimum of 2% of output for every 0.1Hz rise above 50.4Hz (see figure C1). Should this cause power output to be forced below Designed Minimum Operating Level (DMOL) then the Power Park Module may disconnect after a time if operation is not sustainable. However for Power Park Modules, it is acceptable for individual Power Park Units to be disconnected, in order to achieve further power reductions without tripping the module.

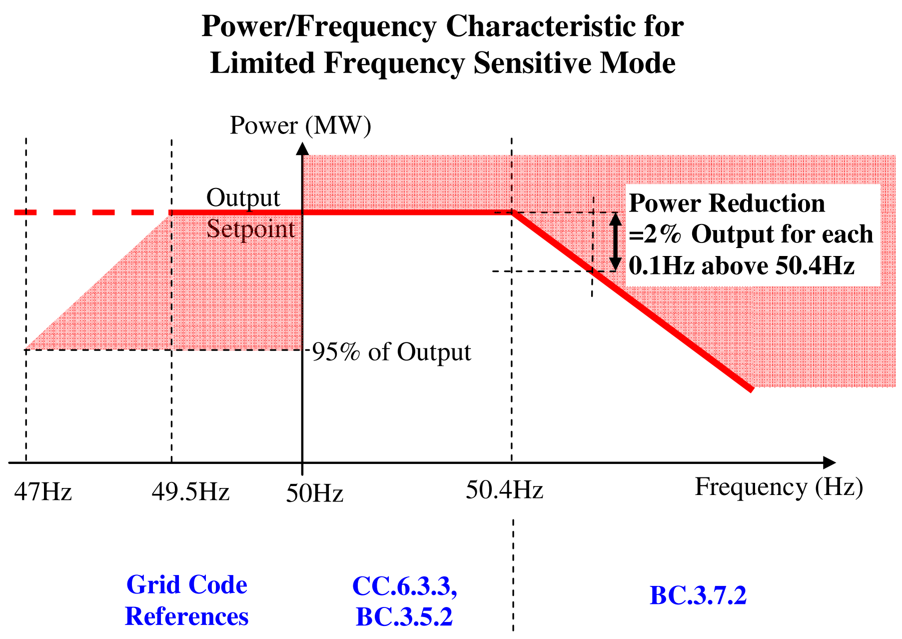


Figure C1 – Limited Frequency Sensitive Mode

Frequency Sensitive Mode is used when selected to provide frequency response services. In this mode the Power Park Module must adjust the active power output in response to any frequency change according to the agreed droop characteristic (between 3-5%). For the purposes of the Mandatory Services Agreement the frequency response performance is measured in terms of the response achieved after a given duration. When system frequency exceeds 50.5Hz the requirements of Limited Frequency Sensitive Mode apply so that the Power Park Module must further reduce output by a minimum of 2% of output for every 0.1Hz rise above 50.5Hz (see figure C2). Should this cause power the output to be forced below the Designed Minimum Operating Level (DMOL) then the Power Park Module may disconnect from the system after a time if operation is not sustainable. However for Power Park Modules, it is acceptable for individual Power Park Units to be disconnected, in order to achieve further power reductions without tripping the module.

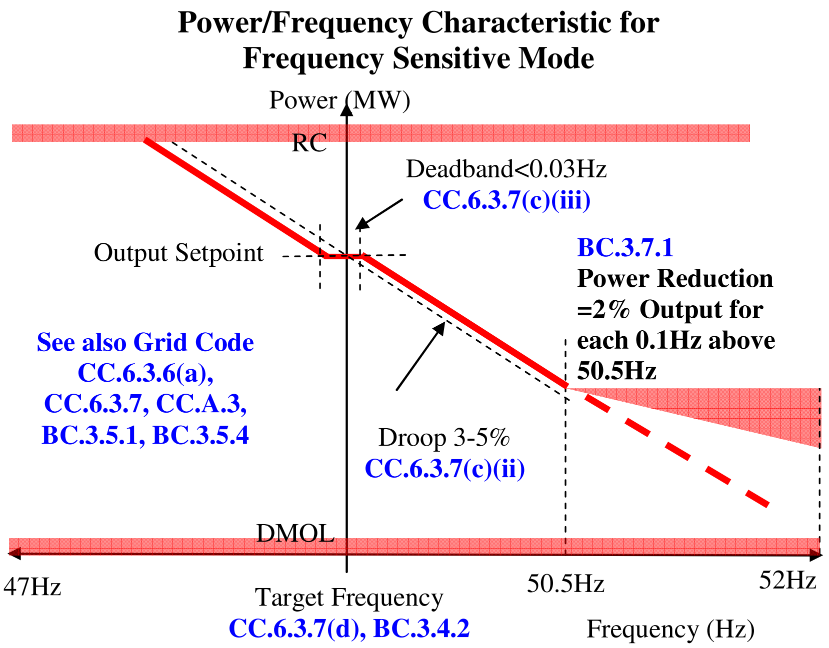


Figure C2 – Frequency Sensitive Mode

Governor / Load Controller

The correct design and coordination of the governor and load controller (or module controller in the case of a Combined Cycle Gas Turbine (CCGT) plant) has been an important issue in compliance of the Grid Code and Mandatory Services requirements. The design details are site specific and there are many ways of meeting the requirements. This section helps to focus on the control issues and gives a simple description on the functional requirements which will help plant designers to appreciate the control needs.

Target Frequency

If a generating unit is required to have a Frequency control device as specified in CC6.3.7 it must also have the facility to accept and act upon Target Frequency instruction from National Grid. In order to adjust electric clock time the Grid Operator may instruct settings of 49.95Hz or 50.05Hz. However, under exceptional circumstances, the instructed settings could be outside this range. A minimum setting range from 49.90Hz to 50.10Hz is required.

Where there is concern on the implementation of this function a test may be suggested where target frequency is adjusted and the affect on active power output of the generating unit is recorded.

Operating Configurations

Figure C.1 shows a simplified schematic diagram of a governor/load controller for a gas turbine. The same control concept applies to conventional thermal plant and CCGTs. With the appropriate setting of the Auto/Manual and Frequency Compensated switches, three basic operating configurations (Figures C2A, C2B and C2C) can be obtained.

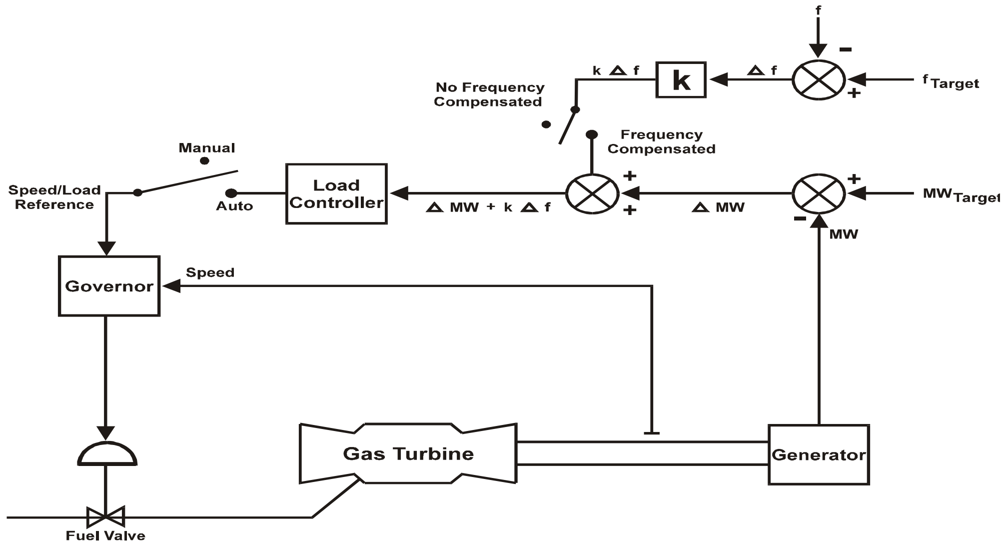


Figure C.3 Schematic Diagram of Gas Turbine Governor / Load Controller

Configuration 'A' (Figure C4A) corresponds to manual governor operation and the generator output can be altered by manually adjusting the speed/load reference setting. This operating configuration is unacceptable since the target frequency setting is unavailable and the secondary response is unreliable (Figure C3) and does not meet the Grid Code/Mandatory Services requirements.

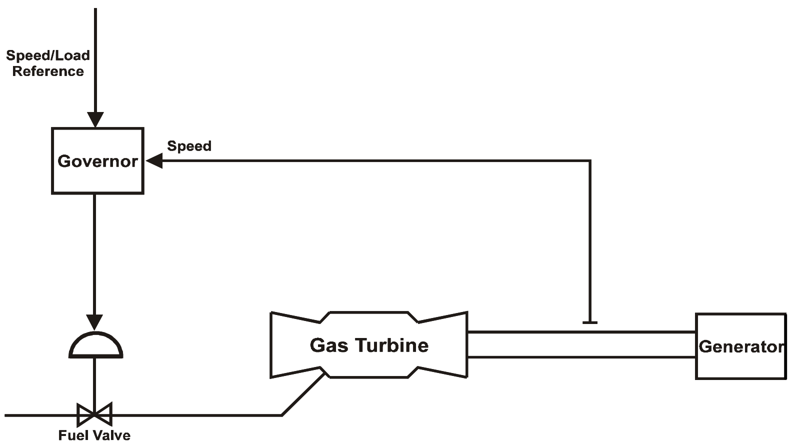


Figure C.4A Governor without Load Controller

Configuration 'B' (Figure C.4B) corresponds to automatic governor and load control. This configuration is unacceptable because of the unavailable target frequency facility and the unsustainable Secondary and High frequency responses (Figure C.3).

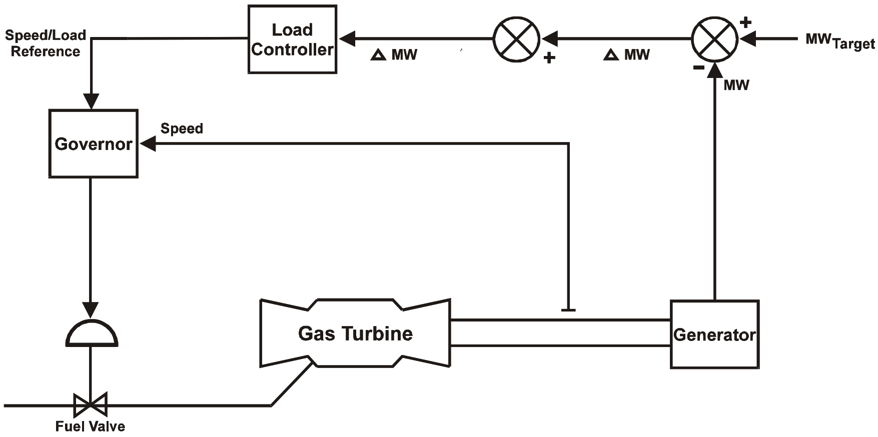


Figure C.4B Governor with MW Target Correction

Configuration 'C' (Figure C.4C) corresponds to an automatic governor with frequency compensated load control. This configuration satisfies both the Grid Code and Mandatory Services requirements.

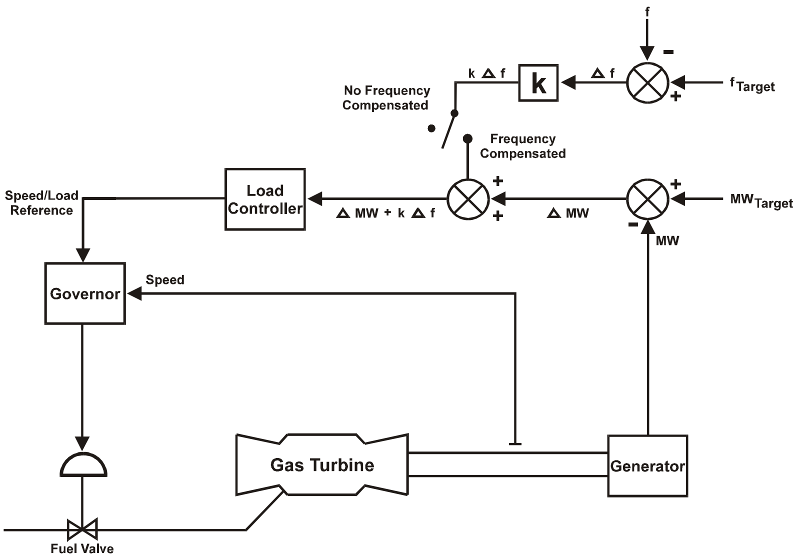


Figure C.4C Governor with Frequency Compensated MW Target Correction

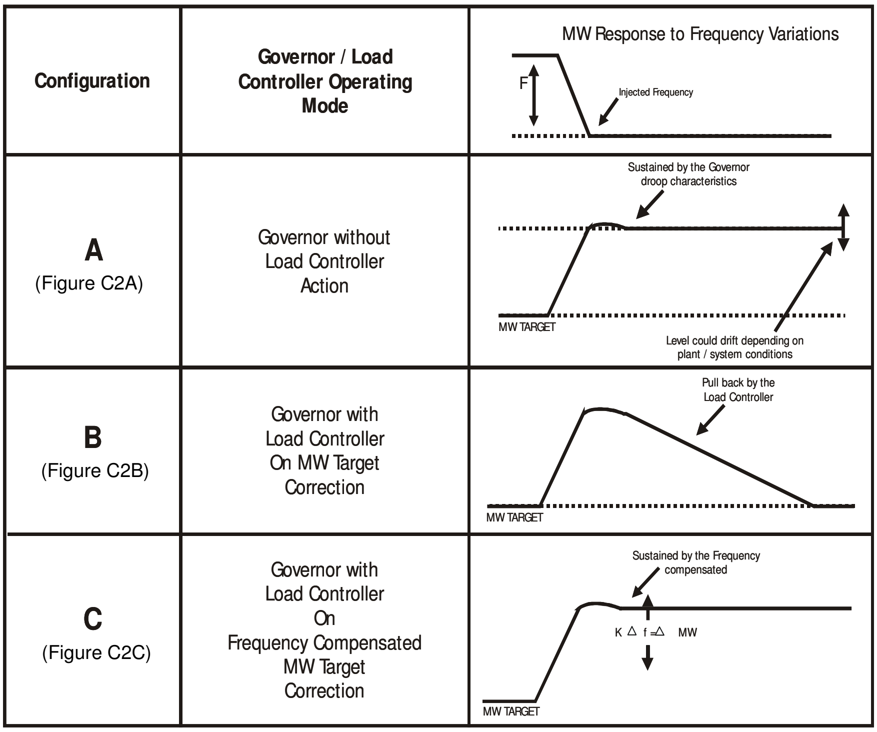


Figure C.5 Effect of Governor / Load Controller Configuration on Plant Response

Mechanical Flyball Governors

Pre-vesting (ex CEGB) conventional plant was originally designed using mechanical flyball governors. The governor acts directly on the primary relay to increase the governor oil pressure and hence open the governor valve. At the same time the load controller demands an increase in oil pressure by controlling the speeder gear motor.

In order to facilitate frequency response deviations correctly the variation will have to be injected to both the inner (flyball governor) and outer (load controller) control loops. Injecting a frequency deviation signal into a flyball governor is difficult but a response has been achieved by manually turning a handwheel. The affect of the handwheel on the output of the unit will need to be understood by the Generator prior to the tests in order to calibrate the response.

Coordination of the speeder gear and handwheel operation allows the correct implementation of the specified frequency changes into both control loops and successful frequency response tests have been achieved by this method.

Maintaining output with falling Frequency

For Limited Frequency Sensitive operation, as specified in BC.3.5.2 and BC.3.7.2, the output of the generator must achieve the CC.6.3.3 requirement up to 50.4Hz above which a minimum power reduction rate of 2% per 0.1Hz must be achieved. Below 50Hz and to 49.5Hz the generating unit is required to maintain output without influence from the reduction in system frequency.

Below 49.5Hz the output is permitted to reduce but only at a rate not greater than pro-rata with the falling frequency. So for a 1% fall in system frequency up to a 1% reduction in output is permissible.

As specified in OC5.5.4 the CC6.3.3 minimum requirement applies up to ambient conditions of 25^{o}C. Above this temperature any special measures employed to achieve CC.6.3.3 compliance at 25^{o}C must be maintained but the minimum requirement set out in CC.6.3.3 need not be achieved.

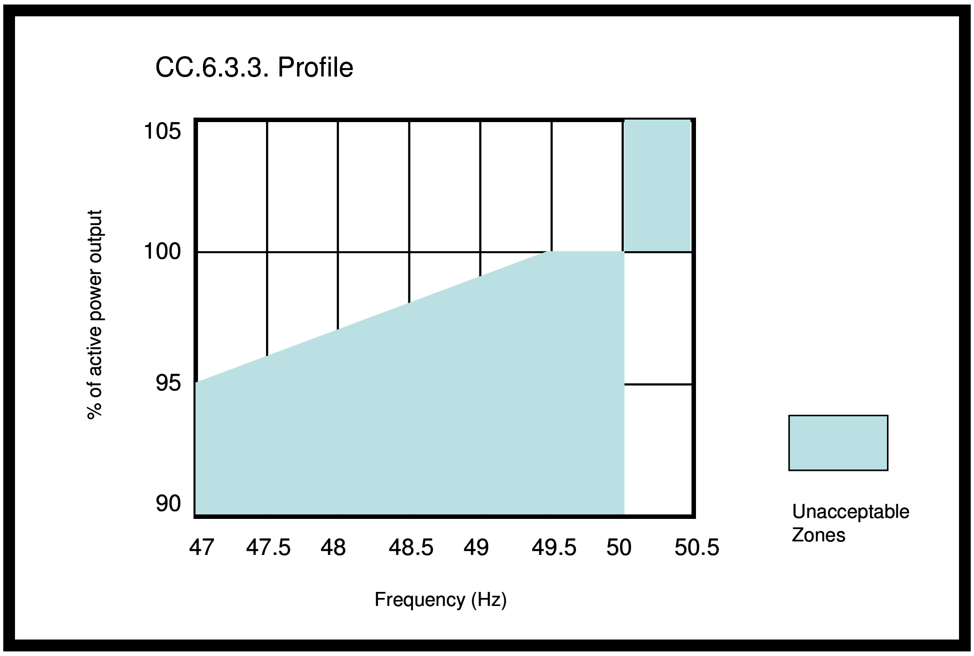


Figure C.6 CC.6.3.3 Profile Indicating Unacceptable Zones.

National Grid will require the User to demonstrate a generator unit performance in accordance with the above requirements. This should comprise providing suitable information prior to the connection of the generating unit in support of a Grid Code compliant design strategy, demonstration of capability where possible with functionality testing and ongoing continuous monitoring of performance.

The User will need to supply National Grid with information relating to the plants MW output, speed and ambient temperature performance characteristics and the relevant design methodology employed within the control system, to ensure the necessary correction to the plant output to meet the CC.6.3.3 and BC.3.7.2 requirements.

Following design of the control system, the User will propose and agree a test procedure with National Grid, which will demonstrate how the plant output power responds to changes in system frequency and ambient conditions (e.g. by frequency and temperature injection methods). This functionality test should be included in a test procedure. On satisfactory conclusion of the above, National Grid would consider the Users plant to be compliant.

As part of the ongoing monitoring provision set out in OC.5.4 the performance of a generating unit can be monitored by National Grid to confirm compliance with the Grid

Code. Where a significant frequency incident occurs or National Grid suspects the performance of a generating unit is not maintaining compliance with CC.6.3.3 the Generator may be asked to provide National Grid with output data from its generating units. National Grid will discuss any concerns with the User as part of the normal and ongoing liaison process.

Compliance Testing Requirements

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

It is required that a complete module is tested under normal operating mode (i.e. combined cycle) with the Gas Turbine Inlet Guide Vane (IGV) Control in operation. A frequency disturbance can be simulated by injecting the required frequency variation signals to both the governor speed reference point and the load controller target frequency set point (See Figure C.4). An overview of the generic test sequence is described in C.6. The test procedures are designed to be flexible to accommodate possible site operating conditions. However, any variations have to be agreed with National Grid.

If a CCGT station has more than one identical module, all tests will be carried out on one of the complete modules. It is an option to reduce the testing requirements on any subsequent units within the same power station where practical. It will be acceptable to use the test derived matrices to cover the other modules if they have the same design and control characteristics.

Signals should be raw i.e. taken directly from a transducer or signal source. Should there be any problem; National Grid should be informed immediately.

Dual Fuelled and Bio-Fuelled Power Stations

For any power stations including CCGT which are capable of running on alternative fuels, then additional governor response tests will be required to demonstrate performance when running on these fuels. Depending on plant design, detailed tests will be agreed between National Grid and the User at the early stage of the compliance process. This could be a subset of the full set of tests

A power station that runs on bio-fuel all the time and large enough to require frequency response performance, should undergo the full set of governor tests shown in OC5.A.2.8. If bio-fuel is used as a supplement to the main fuel then tests are necessary if the frequency response performance change. This could be a subset of the tests indicated in OC5.A.2.8 and will be agreed between National Grid and the User.

Test Following DCS Replacement

If the DCS (Distributed Control System) of an existing plant is replaced it will be necessary to do some frequency response testing following such replacement to confirm there has been no adverse impact on the previously tested performance. Assuming that there is no major change to response delivery, this could be a subset of the tests indicated in OC5.A.2.8 and should be discussed and agreed with National Grid prior to testing. If the response of the unit has been changed then the full set of response tests will be required.

Tests for CC.6.3.3 functionality

Where additional action is taken to maintain output compliant with CC.6.3.3 the manufacturers should propose tests that demonstrate the functionality by injection of a falling frequency into the control system. Where possible the generating unit control should be adjusted to simulate action as if the ambient conditions are 25°C. Where different control functionality acts at different levels of falling frequency separate injections should be proposed to demonstrate each separate functionality.

Where the functionality involves overfiring of the plant to achieve compliance it is permissible to limit the extent of overfiring to limit the adverse affects on the plant for the purposes of the test provided this is explained in the test procedure and the level of response with limited overfiring is identified in advance.

Tests on ex CEGB Auxiliary GTs

The following is a high level functional description of tests designed to demonstrate the robustness of the ex CEGB auxiliary OCGT's governor control system following refurbishment.

The tests are designed to check the integrity of the limits on the major control elements and to check the response and stability of the control systems to frequency disturbances.

Ref	Step	Description
		TESTS AT 100% LOAD
GSD		**Governor Speed Droop Test** Adjust generator speed control loop gain so that a change in generator speed of 120 rpm changes the machine output from 100% load to full speed no load (FSNL). 120 rpm corresponds to 2 Hz and 4% droop. From 100% to FSNL decrease the speed reference in steps of 20rpm until FSNL is achieved.
		TESTS AT 50% LOAD
SC	 1 2 3	**Speed Control Limit Test (if applicable)** Reduce speed set point to just above that for the 50% load value. Apply a step increase to the generator speed reference to prompt the speed limit to control. Remove step and return set point to normal value.

CDP	 1 2 3	**<u>Compressor Discharge Pressure (CDP) Control Limit Test</u>** Reduce the CDP set point to just above that required for 50% load. Apply a step increase to the generator speed reference to prompt the CDP limit to control. Remove step and return set point to normal value.
EGT	 1 2 3	**<u>Exhaust Gas Temperature (EGT) Control Limit Test</u>** Reduce the EGT set point to just above that required for 50% load. Apply a step increase to the generator speed reference to prompt the EGT limit to control. Remove step and return set point to normal value.
F	1 2	Apply a -0.2Hz step to the generator speed reference, hold for 60 seconds or until conditions stabilise. Remove step and allow conditions to stabilise.
G	1 2	Apply a +0.2Hz step to the generator speed reference, hold for 60 seconds or until conditions stabilise. Remove step and allow conditions to stabilise.
H	1 2	Apply a -0.5Hz step to the generator speed reference, hold for 60 seconds or until conditions stabilise. Remove step and allow conditions to stabilise.
I	1 2	Apply a +0.5Hz step to the generator speed reference, hold for 60 seconds or until conditions stabilise. Remove step and allow conditions to stabilise.

The following table give a typical set of signals to be recorded for an ex CEGB Auxiliary OCGT. This list is generic and therefore the schedules may be adjusted to suite site requirements and verification of the appropriate control system model. The list of signals to be provided should be included in the test procedure agreed with National Grid.

	Unit	Signal Range	Signal Representation
Active Power Output	MW	0-10V	0 to 1pu
Speed	RPM	+/-10V	1 +/- 0.1pu
Compressor Discharge Pressure (Each Engine)	BAR	0-10V	0 to 1pu
Exhaust Gas Temperature	^{o}C	0-10V	0.5 to 1.0pu
Fuel Demand	%	0-10V	0 to 1pu
Fuel Valve Position (Each Engine)	%	0-10V	0 to 1pu

Preliminary Frequency Response Testing

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

Typical injection locations at the governor and load controller are shown in Figure C.7.

In order to avoid the risk of re-testing, it is important that the injection method and the plant control are proved well in advance of the main tests by the station or site contractor. A preliminary test is therefore required to demonstrate that the plant responds in a generally correct manner and that the frequency injections can be made correctly.

At all times and for all tests, the target frequency selected on the generating plant is that instructed by the National Grid Control Centre. This should normally be 50.00Hz but may occasionally be set slightly high or low to correct electric clock time errors.

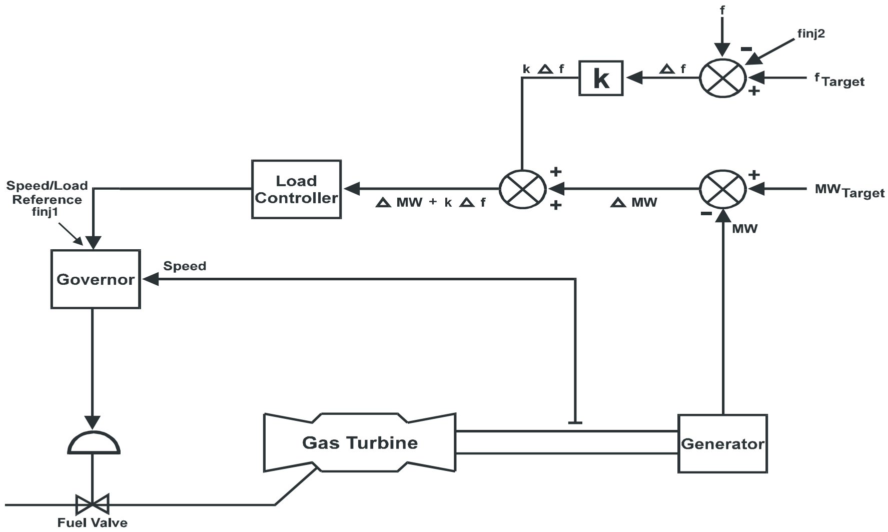
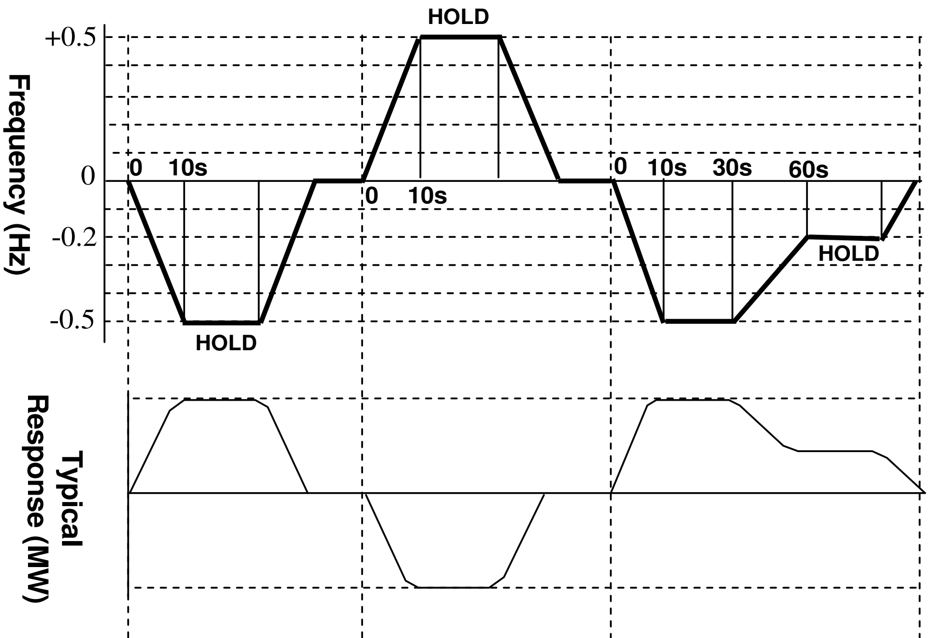


Figure C.7 Governor with Frequency Compensated MW Target Correction

Tests are applied as ramp injections over 10 seconds, 1 second or as step injections depending upon the particular test. In addition there are profile tests which aim to simulate the affect on the system frequency of a large loss. The simple ramp and more complex profile injection with multiple stages required for the preliminary frequency response tests are indicated in the diagram below.



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

The generic preliminary frequency response procedure is given in OC5.A.2.8.4

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

National Grid Witnessed Frequency Response Testing Schedule

Grid Code OC5.A.2.8. Figure 1 and Figure 2 give the ramps and step frequency injection tests required at different loading levels (i.e. MLP 6 to MLP 1). The corresponding test sequence is outlined below with the initial test establishing the maximum steady state output condition of the plant (i.e. MLP 6). A full generic procedure is provided in Appendix 0 as an example.

1. Establish Maximum Plant Capacity as Loading Point MLP6

(a) Switch GT governors to manual and raise load demand to confirm the maximum output level at the base settings.

(b) Record plant and ambient conditions.

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

(a) Operate the plant at MLP 6

(b) Inject ramp/profiled frequency changes simultaneously into the GT governor and load controller (i.e. Tests 1-4 in OC5.A.2.8 Figure 1) and record plant responses.

(c) Inject the calculated frequency change simultaneously into the GT governor and load controller to simulate the load rejection (i.e. Tests BC1 in OC5.A.2.8 Figure 1) and record plant responses.

(d) Inject ramp rise in frequency over 30 seconds simultaneously into the GT governor and load controller (i.e. Test BC2 in OC5.A.2.8 Figure 1) and record plant responses.

3. Response Tests at Loading Point MLP6 (Maximum Output) in Limited Frequency Sensitive Mode (LFSM)

(a) Operate the plant at MLP 6

(b) Inject the calculated frequency change simultaneously into the GT governor and load controller to simulate the load rejection (i.e. Tests BC3 in OC5.A.2.8 Figure 1) and record plant responses.

(c) Inject ramp rise in frequency over 30 seconds simultaneously into the GT governor and load controller (i.e. Test BC4 in OC5.A.2.8 Figure 1) and record plant responses.

4. Response Tests at Loading Point MLP5 (0.95 RC)

(a) Operate the plant at MLP5.

(b) Conduct tests 5-7 as shown in OC5.A.2.8 Figure 1 and record plant responses.

(c) Conduct test A as shown in OC5.A.2.8 Figure 2 to establish the robustness of the control system under simulated extreme disturbances (as could occur under system islanding or system split conditions).

5. Response Tests at Loading Point MLP4 (0.8 RC)

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

(b) Conduct tests 8-14 as shown in OC5.A.2.8 Figure 1 and record plant responses.

(c) Conduct tests D - I as shown in OC5.A.2.8 Figure 2 to establish the GT dead band, and step response characteristics for governor modelling purposes.

(d) Conduct test J as shown in Figure 2 to establish the robustness of the control system under simulated extreme disturbances (e.g., system islanding or system split).

6. Response Tests at Load Point MLP3 (0.7 RC)

(a) Operate the plant at MLP3.

(b) Conduct tests 15 to 17 as shown in OC5.A.2.8 Figure 1 and record plant responses.

7. Response Tests at Minimum Generation MLP2 (<=0.65 RC)

(a) Operate the plant at MG.

(b) Conduct tests 18 - 22 as shown in OC5.A.2.8 Figure 1 and record plant responses.

8. Response Tests at Designed Minimum Operating Level MLP1 (0.55 RC)

(a) Operate the plant at DMOL.

(b) Conduct tests 23 - 26 as shown in OC5.A.2.8 Figure 1 and record plant responses.

(c) Conduct test K as shown in OC5.A.2.8 Figure 2 to establish the step response characteristics for governor modelling purposes.

Generic Governor Frequency Response Test Procedure

Since the governor response tests described above are to be arranged and conducted by the Generator, it is their responsibility to propose a test programme to suit their site specific requirements. A typical example of the test procedure based on OC5.A.2.8 Figures 1 and 2 is given below. This procedure is required to be submitted to National Grid for approval before an ION is issued.

Initial Checks on Maximum Plant Capability at MLP6, Plant in LFSM	
Step	**Actions**
1	Record plant MLP 6 condition including levels for GT's and ST and module MW output, ambient temperature, governor control signals and steam conditions.
2	Change GT governor control to manual and increase output power demand to maximum.
3	Record plant conditions when plant is thermally Stabilised.
4	Reset governor to normal operating mode and allow MLP 6 condition to be established

Injection Tests at MLP6, Plant in FSM				
Step	**Test No.**	**Actions**	**Frequency Injection**	**Notes**
5	1	• Inject 0.10Hz frequency rise over 10 sec • Hold until conditions stabilise	+0.10Hz	
6		• Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 6	-0.10Hz	
7	2	• Inject -0.20Hz frequency fall over 10 sec • Hold until conditions stabilise	-0.20Hz	
8		• Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 6	+0.20Hz	
9	3	• Inject 0.20Hz frequency rise over 10 sec • Hold until conditions stabilise	+0.20Hz	
10		• Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 6	-0.20Hz	
11	4	• Inject 0.50Hz frequency rise over 10 sec • Hold until conditions stabilise	+0.50Hz	
12		• Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 6	-0.50Hz	
		<u>Plant in FSM</u>		
13	BC1	• Inject +2.0* Hz frequency rise over 1 sec • Hold until conditions stabilise	+2.0 Hz *	Part of functionality test for islanding CC.6.3.7 (c)(i)
14		• Remove the injection signal • Hold until conditions stabilise at MLP 6	-2.0 Hz	
		<u>Plant in FSM</u>		
15	BC2	• Inject +0.6 Hz frequency rise over 30 sec • Hold until conditions stabilise	+0.6 Hz	Part of functionality test for BC.3.7.1
16		• Remove the injection signal • Hold until conditions stabilise at MLP 6	-0.6 Hz	

See Note 1	L	**Plant in FSM** • Record normal system variation in frequency and active power of the generating unit over at least 10 minutes	No injection	Part of functionality test for BC.3.7
Switch to Limited Frequency Sensitive Mode				
17 18	BC3	**Plant in LFSM** • Inject +2.0* Hz frequency rise over 1 sec • Hold until conditions stabilise • Remove the injection signal • Hold until conditions stabilise at MLP 6	+2.0 Hz -2.0 Hz	Part of functionality test for islanding CC.6.3.7 (c)(i)
19 20	BC4	**Plant in LFSM** • Inject +0.6 Hz frequency rise over 30 sec • Hold until conditions stabilise • Remove the injection signal • Hold until conditions stabilise at MLP 6	+0.6 Hz -0.6 Hz	Part of functionality test for BC.3.7.2

* This will generally be +2.0Hz unless an injection of this size causes a reduction in plant output that takes the operating point below **Designed Minimum Operating Level** in which case an appropriate injection should be calculated in accordance with the following:
For example 0.9Hz is needed to take an initial output 65% to a final output of 20%. If the initial output was not 65% and the **Designed Minimum Operating Level** is not 20% then the injected step should be adjusted accordingly as shown in the example given below

Initial Output	65%
Designed Minimum Operating Level	20%
Frequency Controller Droop	4%
Frequency to be injected = (0.65-0.20)x0.04x50 =	0.9Hz

Injection Tests at MLP 5, Plant in FSM				
21 22 23	5	• Inject -0.50Hz frequency fall over 10 sec • Hold for 20 sec • Inject 0.30Hz frequency rise over 30 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 5	-0.50Hz +0.30Hz	
24 25	6	• Inject 0.20Hz frequency fall over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 5	-0.20Hz +0.20Hz	
26 27	7	• Inject 0.50Hz frequency rise over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 5	+0.50Hz -0.50Hz	
28 29	A	• Inject 1.0Hz/sec frequency fall over 2 sec • Hold for 30 sec • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 5	-2.0Hz +2.0Hz	To assess plant performance under islanding and system split Conditions

Injection Tests at MLP 4, Plant in FSM				
30 31 32	8	• Inject -0.50Hz frequency fall over 10 sec • Hold for 20 sec • Inject 0.30Hz frequency rise over 30 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 4	-0.50Hz +0.30Hz +0.20Hz	
33 34	9	• Inject -0.10Hz frequency fall over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 4	-0.10Hz +0.10Hz	
35 36	10	• Inject 0.10Hz frequency rise over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 4	+0.10Hz -0.10Hz	
37 38	11	• Inject -0.20Hz frequency fall over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 4	-0.20Hz +0.20Hz	
39 40	12	• Inject 0.20Hz frequency rise over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 4	+0.20Hz -0.20Hz	
41 42	13	• Inject -0.50Hz frequency fall over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 4	-0.50Hz +0.50Hz	
43 44	14	• Inject 0.50Hz frequency rise over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 4	+0.50Hz -0.50Hz	
45 46	D	• Inject -0.02Hz frequency fall as a step change • Hold until conditions stabilise • Remove the injection signal • Hold until conditions stabilise at MLP 4	-0.02Hz +0.02Hz	To assess the governor deadband
47 48	E	• Inject 0.02Hz frequency rise as a step change • Hold until conditions stabilise • Remove the injection signal • Hold until conditions stabilise at MLP 4	+0.02Hz -0.02Hz	To assess the governor deadband
49 50	F	• Inject -0.20Hz frequency fall as a step change • Hold until conditions stabilise • Remove the injection signal • Hold until conditions stabilise at MLP 4	-0.20Hz +0.20Hz	To assess step response characteristics of plant
51 52	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 -0.20Hz	To assess step response characteristics of plant
53 54	H	• Inject -0.50Hz frequency fall as a step change • Hold until conditions stabilise • Remove the injection signal • Hold until conditions stabilise at MLP 4	-0.50Hz +0.50Hz	To assess step response characteristics of plant
55 56	I	• Inject 0.50Hz frequency rise as a step change • Hold until conditions stabilise at MLP 4 • Remove the injection signal • Hold until conditions stabilise at MLP 4	+0.50Hz -0.50Hz	To assess step response characteristics of plant

57 58	J	• Inject 1.0Hz/sec frequency fall over 2 sec • Hold for 30 sec • Remove the injection signal • Hold until conditions stabilise at OLP	-2.0Hz +2.0Hz	To assess plant performance under islanding and system split conditions
See Note 1	M	• Record normal system variation in frequency and active power of the generating unit over at least 10 minutes	No injection	Part of functionality test for BC.3.6 & BC.3.7
Switch to Limited Frequency Sensitive Mode				
See Note 2	N	**Plant in LFSM** • Record normal system variation in frequency and active power of the generating unit over at least 10 minutes • Switch to Frequency Sensitive Mode	No injection	Part of functionality test for BC.3.6 & BC.3.7

Injection Tests at MLP 3, Plant in FSM				
59 60 61	15	• Inject -0.50Hz frequency fall over 10 sec • Hold for 20 sec • Inject 0.30Hz frequency rise over 30 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 3	-0.50Hz +0.30Hz +0.20Hz	
62 63	16	• Inject 0.50Hz frequency rise over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 3	+0.50Hz -0.50Hz	
64 65 66	17	• Inject -0.80Hz frequency fall over 10 sec • Hold for 20 sec. • Inject 0.30Hz frequency rise over 30 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 3	-0.80Hz +0.30Hz +0.50Hz	

Injection Tests at MLP2, Plant in FSM				
67 68 69	18	• Inject -0.50Hz frequency fall over 10 sec • Hold for 20 sec • Inject 0.30Hz frequency rise over 30 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 2	-0.50Hz +0.30Hz +0.20Hz	
70 71	19	• Inject -0.20Hz frequency fall over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 2	-0.20Hz +0.20Hz	
72 73	20	• Inject 0.20Hz frequency rise over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 2	+0.20Hz -0.20Hz	
74 75	21	• Inject -0.50Hz frequency fall over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 2	-0.50Hz +0.50Hz	

76 77 78	22	• Inject -0.80Hz frequency fall over 10 sec • Hold for 20 sec • Inject 0.30Hz frequency rise over 30 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 2	-0.80Hz +0.30Hz +0.50Hz	

Injection Tests at MLP 1, Plant in FSM				
79 80 81	23	• Inject -0.50Hz frequency fall over 10 sec • Hold for 20 sec • Inject 0.30Hz frequency rise over 30 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 1	-0.50Hz +0.30Hz +0.20Hz	
82 83	24	• Inject -0.20Hz frequency fall over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 1	-0.20Hz +0.20Hz	
84 85	25	• Inject 0.20Hz frequency rise over 10 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 1	+0.20Hz -0.20Hz	
86 87 88	26	• Inject -0.80Hz frequency fall over 10 sec • Hold for 20 sec • Inject 0.30Hz frequency rise over 30 sec • Hold until conditions stabilise • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 1	-0.80Hz +0.30Hz +0.50Hz	
89 90	K	• Inject -0.5Hz frequency fall over 1 sec • Hold for 30 sec • Remove the injection signal over 10 sec • Hold until conditions stabilise at MLP 1	-0.5Hz +0.5Hz	To assess plant performance under islanding and system split conditions

Note 1: Tests L and M in OC5.A.2.8. Figure 2 shall be conducted if in this range of tests 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 will consist of monitoring the generating unit and CCGT Module in Frequency Sensitive Mode during normal system frequency variations without applying any injection.

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

Appendix D Contacting National Grid

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

Contact Address:

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

National Grid

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

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