nationalgrid

Stage 03: Code Administration Consultation

Grid Code

GC0087

Requirements for Generators Frequency Provisions

What stage is this document at?

01	Modification Proposal
02	Workgroup Report
03	Code Admin Consultation
04	Draft Final Modification Report
05	Report to the Authority

This Code Administrator Consultation outlines the information required for interested parties to form an understanding of Frequency Response Requirements, outlines the proposals to modify the Grid Code, Distribution Code and G99 to address these concerns, and seeks the views of interested parties in relation to the proposals outlined.

The issue we are trying to address is the implementation of the EU Code - Requirements for Generators in respect of Frequency Response.

The purpose of this document is to consult on Requirement for Generators Frequency Provisions with interested industry members. Representations received in response to this consultation document will be included in the Code Administrator's Draft Final Modification Report that will be furnished to the Grid Code Panel for their decision.

Parties are requested to respond by 11/05/2017 to Grid.Code@nationalgrid.com.

Published on: **20/04/2017**
Length of Consultation **15 Working Days**
Response by: **11/05/2017**

High Impact: *All Generators and Interconnectors*

Medium Impact: *None*

Low Impact: *None*

Contact us: ***The Code Administrator is available to help and support the drafting of any modifications, including guidance on completion of this template and the wider modification process. Please contact the Panel Secretary: e-mail: ellen.bishop @nationalgrid.com or grid.code@nationalgrid.com***

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Any Questions?

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Timetable

The Code Administrator recommends the following timetable:	
Code Administration Consultation Report issued to the Industry	20 April 2017
Draft Final Modification Report presented to Panel	17 May 2017
Modification Panel decision	17 May 2017
Final Modification Report issued the Authority	22 May 2017

1 Summary

1.1 The European Commission has established a network code on requirements for grid connection of generators (RfG) to enable and promote cross-border trade and exchange of electricity (Commission Regulation (EU) 2016/631). Completion of a fully functioning and interconnected internal energy market is crucial to maintaining security of energy supply, increasing competitiveness and ensuring that all consumers can purchase energy at affordable prices.

1.2 GC0087 sets out to implement the EU (RfG) with regard to Frequency Response. Specifically, Frequency Ranges, Frequency Response ((including LFSM-O (Limited Frequency Sensitive Mode-Overfrequency), LFSM-U (Limited Frequency Sensitive Mode Underfrequency) and FSM (Frequency Sensitive Mode(FSM)), Maintenance of Constant Active Power, Power Output with Falling Frequency, Monitoring and RoCoF (Rate of Change of Frequency) Withstand Capability.

1.3 It was agreed by the workgroup at the start of the process that the main aim was to try to align the (RfG) as closely as possible with what is currently specified in Grid Code, but also refining and improving current practice/definitions where possible.

1.4 Many of the frequency response definitions are the same as or similar to existing Grid Code definitions. FSM is defined in a different way, but LFSM-U and RoCoF Withstand Capability are not currently defined in Grid Code so as a consequence greater time and focus was given to these issues by the workgroup.

1.5 The Grid Code Review Panel (GCRP) convened a Workgroup to investigate the implementation of the EU RfG code with regard to frequency response and report its findings back to the Panel.

1.6 Towards the end of the workgroup process for GC0087, it was agreed at GC0048 (the joint GCRP and DCRP workgroup considering all aspects of the RfG) that GC0087 should come under the remit of GC0048 and should therefore also include issues affecting Distribution Network Operators and generators connected to the distribution system.

2 Why Change?

What is ‘Requirements for Generators’?

2.1 RfG sets harmonised rules for grid connection across Europe of power generation modules of 800 Watts in capacity or greater. It seeks to provide a clear legal framework for grid connections, facilitate Union-wide trade in electricity, ensure system security, facilitate the integration of renewable electricity sources, increase competition and allow more efficient use of the network and resources.

2.2 EU web page for RfG code text:
http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=OJ:JOL_2016_112_R_0001

2.3 ENTSO-E overview of the European Network Codes: https://www.entsoe.eu/major-projects/network-code-development/Pages/default.aspx

How did it originate?

2.4 The European Third Energy Package was adopted in July 2009, and has been law since March 2011. It is a suite of legislation for both electricity and gas, and is a key step forward in developing a more harmonised European energy market.

2.5 As applied to the electricity supply industry, the Third Energy Package has three key outputs: enhancing sustainability and helping the European Union (EU) meet its decarbonisation obligations; ensuring security of supply in light of a changing generation mix; and creating a single European Market for Electricity.

2.6 As is common to all EU law, regulations apply directly to the member states, whereas directives require transcription into national law. In particular, Directive 2009/72/EC (concerning common rules for the internal market in electricity) was transcribed into UK Law via The Electricity and Gas (Internal Markets) Regulations 2011.

2.7 The Third Energy Package also delivered the formation of the European Network of Transmission System Operators for Electricity and Gas; ENTSO-E and ENTSO-G respectively. ENTSO-E led the drafting of the RfG before the text was approved by EU member states in June 2015.

When does it apply?

2.8 RfG ‘Entered Into Force’, the formal ratification of the legislation into the Official Journal of the European Union, on 17 May 2016. Member States then have two years to implement the code’s requirements nationally.

2.9 However, there is a point three years after EIF where new power generating modules will either be bound by existing national requirements, or the new RfG requirements. If a power generating module developer has a legally binding contract to procure their main plant items dated before two years after EIF, then they are classed as existing and current national requirements will apply. After this date, the user is classed as ‘New’ and must comply with RfG.

What were ENTSO-E’s objectives when drafting RfG?

2.10 ENTSO-E’s brief when drafting these codes was to realise the broad objectives of the Third Energy Package. ENTSO-E also considered the challenges additional renewable generation would present to the way Transmission Systems are designed and managed. In a world of increasing wind and solar generation, HVDC interconnection and reliance on solid state power conversion technologies, security of supply issues become an increasingly important consideration. Even if RfG was not mandating a need for change, it is expected that similar requirements would need to be introduced at a GB level alone simply to ensure the maintenance of a safe, secure, economic and flexible system.

2.11 From a systems engineering approach, ENTSO-E believes that Transmission Systems and their users (power generating modules, DSOs and demand facilities) should be considered as ‘one system’ comprehensively. They should co-operate closely during normal and disturbed operating conditions in order to preserve or restore system security.

Determining significance

2.12 In particular, power generating modules are fundamental to the design and operational characteristics of the electricity system, playing an important role by providing ancillary services for system balancing/frequency control, voltage control, resilience during disturbances and to assist with system restoration after blackouts.

2.13 RfG therefore specifies power generating module capabilities in this ‘system operability’ context, strives to be technology neutral and focuses primarily on capacity and connection requirements.

2.14 Article 2 of RfG defines power generating modules and related terms as “either a synchronous power-generating module or a power park module”.

Generator Banding

2.15 RfG uses four incremental types of power generating modules (‘A’ to ‘D’) which set a sliding scale of generator technical capabilities to support System Operators. The Transmission System Operation Guideline (TSOG) also uses the RfG banding thresholds to apply data exchange requirements on new *and* existing power generating modules.

Figure 1: Banding criteria

2.16 Each of the four RfG types has an associated connection voltage and installed unit capacity range (MW). For each European synchronous area, MW ceiling levels are set out in RfG for the thresholds between each type. The code also describes the process each member state needs to follow to set their threshold levels (whether this is the ceiling level itself, or values below). A full cost benefit analysis is not mandated as part of this activity.

2.17 Any banding level proposals must be justified, consulted on, and finally approved by the appropriate national regulatory authority (NRA). In the event that modifications to the approved levels are required in future, the same process can be re-run no sooner than 3 years later.

	Type A	Type B	Type C	Type D
Connection Voltage:	<110kV	<110kV	<110kV	≥110kV
	MW range for Power Generating Modules	**MW range for Power Generating Modules**	**MW range for Power Generating Modules**	**MW range for Power Generating Modules**
Continental Europe	800W-1 MW	1 MW-50MW	50 MW-75 MW	75 MW+
Great Britain	**800W-1 MW**	**1 MW-50MW**	**50 MW-75 MW**	**75 MW+**
Nordic	800W-1.5 MW	1.5 MW-10MW	10 MW-30 MW	30 MW+
Ireland and Northern Ireland	800W-0.1 MW	0.1 MW-5MW	5 MW-10 MW	10 MW+
Baltic	800W-0.5 MW	0.5 MW-10MW	10 MW-15 MW	15 MW+

Table 1: Banding Ranges per European Area

2.18 For GB, there are two proposed options for the banding level which have been formed following industry consultation, although it is acknowledged further dialogue continues with stakeholders in this area.

Type	Option 1 - High	Option 2 - Medium
A	800W – 1MW	800W -1MW
B	1-50MW	1-10MW
C	50-75MW	10-50MW
D	75MW	50MW+

Table 2: UK Banding Options

Background to UK Frequency Work

2.19 In September 2010, National Grid presented paper PP01/21 to the GCRP entitled "Future Frequency Response Services". This paper summarised the issues associated with meeting the requirements for frequency response arising from significant changes to the generation background. These changes included:

- Substantial increases in renewable generation
- Installed Wind Generation capacity potentially exceeding minimum demand
- Substantial changes in non-renewable generation including (new nuclear and supercritical coal and gas); and
- A change to the Security and Quality of Supply Standards (SQSS) resulting in an increase to the infrequent infeed loss to 1800MW.

2.20 To assess these issues National Grid established a Frequency Response Technical Sub Group (subsidiary to GC0022 "Frequency Response") in November 2010. This sub-group was tasked with:

- Determining the technical need for frequency response services including a review of the minimum primary frequency response requirements:
- Work with manufacturers on the development of a synthetic inertia requirement or equivalent; and
- Advise the Distribution Code Review Panel of the issues associated with the rate of change of frequency and the implications for embedded generation.

2.21 The following conclusions and recommendations were reached by this technical subgroup:

- With a large penetration of wind generation, management of system frequency within SQSS limits was only achieved if variable speed wind turbines and other decoupled generating plant such as HVDC schemes are equipped either with a synthetic inertia capability or a fast primary response capability where the primary frequency response is delivered in less than 10 seconds.

- Frequency response requirements, and hence the volume of curtailment, can be significantly reduced if generation can provide faster frequency response.

- It was recommended that a fast frequency response capability should be developed as it is less challenging to implement than the alternatives (eg synthetic inertia), reduces the risk of further power reductions from wind turbines in the recovery period and avoids complications with df/dt sampling.

- It was noted that there is a need to clarify current primary response requirements to encompass delivery delay times and ramp rates to provide some assurance that frequency containment is achievable.

- The Frequency Response Technical Subgroup Report proposed the development of mandatory provisions for "5 second response from non-synchronous plant". Responses to the workgroup consultation were evenly divided in support and against development of these proposals.

- The consultation also included proposals for the development of clearer requirements for the delivery of frequency response in terms of minimum delay and ramping parameters. The majority of respondents were in favour of developing these requirements.

- The complete report of the technical subgroup conclusions can be found here:
  http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=28745

- Subsequent discussions at the Balancing Services Standing Group (BSSG) confirmed that there was no consensus on the benefit of "5 second response" as a mandatory requirement for new non-synchronous generation.

2.22 Proposals to develop the frequency response provisions of the Grid Code under GC0022 did not reach a consensus and the workgroup Consultation closed on 30 October 2012.

2.23 Paper PP14/59 was presented to the GCRP on 4 November 2014 (see Annex 1). This paper highlighted a number of outstanding defects with the Frequency Response provisions of the Grid Code and proposed that they should be addressed in a new Workgroup with issue reference GC0087.

2.24 A workshop was held on 3 March 2015 and the following tables (3 & 4) detail the issues discussed and highlights the conclusions:

	Issue	Defect	Pros	Cons
a	Mandatory rapid response for non-synchronous generators	The current mandatory capability is not efficient in addressing future frequency response requirements on its own. Non-synchronous equipment does not contribute to system inertia in the same way as synchronous plant does. Faster frequency response will help to manage the resulting higher rates of change of system frequency and reduce the risk of excursions outside limits. It will reduce the total volume and cost of frequency response and allow wind turbines, interconnectors and photo-voltaics to provide more value to the consumer.	Reduced balancing services costs and therefore reduced costs to consumers. Enhanced system security	Increased costs for generators which would be expected to be reflected in prices to consumers. Will require further assessment in the future as the volume of non - synchronous plant increases. There is a possibility that synthetic inertia may be required in the future
b	Clearer delay and ramp-rate requirements	Current provisions leave some uncertainty over the performance requirements for generators delivering frequency response. There is clear system sensitivity to the ramping capability of responsive generation and how quickly response is initiated. How quickly a generator meets its primary response requirement in 10 seconds can be critical.	Clearer ramping requirements and initiation times would reduce uncertainty in calculations of response requirements and in generator compliance assessment. The European Network Codes also ask for these to be defined.	Risk of requirement being too onerous, especially for certain plant types
c	Low Load Operation	Current provisions potentially limit generators' ability to operate at low loads by requiring full response capability whilst operating at or above DMOL. This feature ensures that response is available when generators are running but potentially restricts operation at lower loads unnecessarily.	Facilitates flexible operation from generators and contributing to system inertia and voltage control	Requirements may be complex to define and agree.
d	Alternative on-site sources	Current provisions limit the use of alternative solutions (eg on-site batteries, storage or standby units) due to all units being required to meet the Grid Code rather than the overall output of the site meeting Grid Code.	Alternative ways of providing response. This may however be addressed through the ENTSO-E Requirements for Generators Code	Potentially limited application

Table 3 Options considered at the workshop on 03/03/15

Issue	**Stop/ proceed elsewhere**	**GC0087 Workgroup**		**Comment**
		Develop Proposals	**Put on hold**	
Clearer ramp rate and delay definition		✓		Recognised benefits for all parties. Parameters required for RfG Implementation.
Low Load Operation			✓	Potential benefits recognised. No clear need for a change at this time.
Alternative on-site sources			✓	Potential benefits recognised. No clear need for a change at this time.
Rapid-Frequency Response for non-synchronous generators	✓			Polarised positions on costs and benefits. Need case has to be well quantified by NGET (2015 FES/SOF) before issue can progress further.
Inertial Response from Synchronous generators	✓			NGET to work with generators to verify modelling assumptions

Table 4: Conclusions to the discussion points in table 3

2.25 Once work started on the above issues, it was felt that many of these issues would be incorporated in the new Requirements for Generators (RfG) being imposed under EU code implementation. Therefore GC0087 took responsibility for all frequency related issues of RfG implementation. This required working closely with GC0048, the workgroup looking after all aspects of RfG implementation.

Impact on the System of Diminishing Inertia

2.26 At the beginning of the workgroup process there was discussion around the extent of the issue of diminishing inertia on the system. Work was undertaken to quantify the effect.

3.26 It was noted that the reduction in inertia has many facets including energy efficiency, demand reduction, variable speed drives, change in generation technology etc.

3.27 System inertia is estimated by summing all synchronised machines' inertia (in MW.s) (this is derived from the generators' submitted planning data) on a half hourly basis. Only synchronous machines are included in this calculation, the inertia of inverter connected machines is deemed to be unavailable to the system. Assumptions are made for the value of inertia from demand at approximately 1.83MW.s per MW of demand.

3.28 There is no Grid Code planning standard or SQSS requirement for system inertia. At the present time the NGET control room calculates RoCoF in respect of the largest system loss and the estimated system inertia at the time and takes actions to ensure that RoCoF does not exceed levels which may cause tripping of embedded generators fitted with G59 RoCoF protection.

3.29 The system inertia graphs (Figures 2&3) demonstrate a significant trend of declining system inertia. It was generally felt that the trend is due to the displacement of synchronous plant from the system by reducing demand and increasing non-synchonous generation.

3.30 An average initial delay of 2s when calculating primary response requirements is assumed. This is based on a survey of generator compliance test data, but it was noted that it is not a current Grid Code requirement. A response delay time is specifically defined in RfG.

3.31 Table 5 demonstrates the increased level of reserve expected following the decline in system inertia and the subsequent increased RoCoF rate. This was based on a simplified "lumped" model of the GB system and an assumption that the lumped generator has a 2s initial delay to provide response. Although increased levels of reserve can manage the increased RoCoF risk, there is a point at periods of low demand where there is insufficient space on the system for the amount of part-loaded plant required. A shorter initial delay would mitigate the time to reach 49.2 Hz and the response rate (MW/s) needed.

Inertia (GW.s)	**RoCoF (Hz/s)**	**Time (to reach 49.2 Hz)**	**Response Rate (MW/s)**	**Requirement**			
				Gone Green	Slow Progression	Low Carbon Life	No Progression
360	0.125	9	185	2014/15	2014/15	2014/15	2014/15
225	0.2	4	400	2019/20	2024/25	2024/25	2029/30
205	0.22	3.4	489	2024/25	2024/25	2024/25	2029/30
180	0.25	2.4	679	2024/25	2024/25	2024/25	2029/30
150	0.3	1.2	1148	2024/25	2024/25	2024/25	2034/35

Table 5 (excerpt from 2014 SOF)

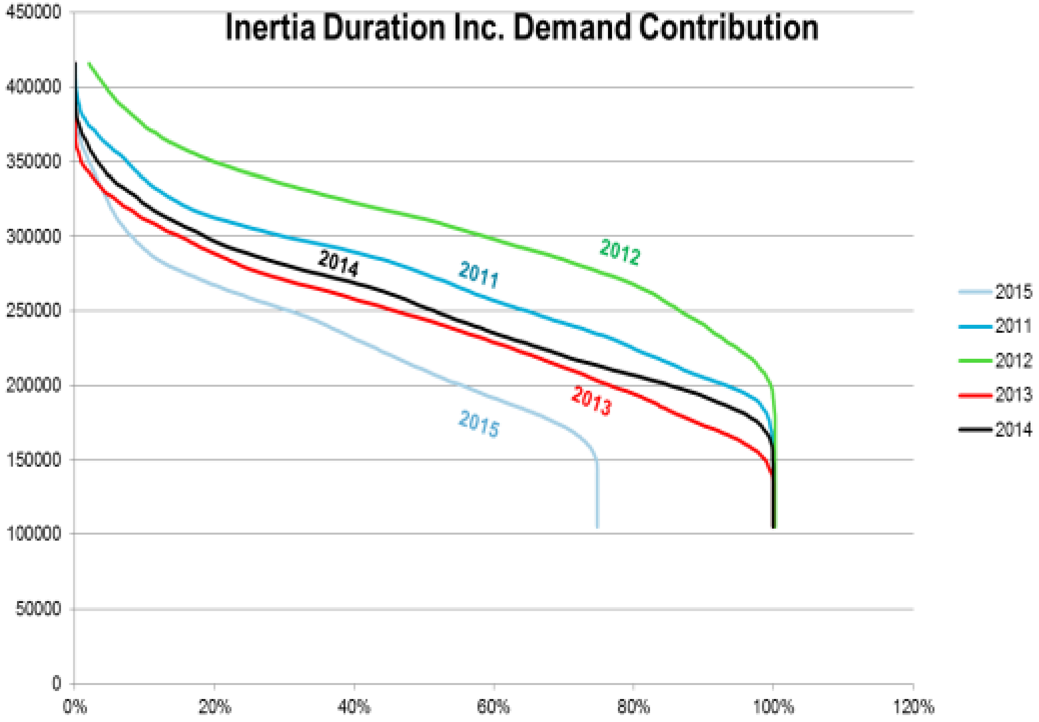


Figure 2

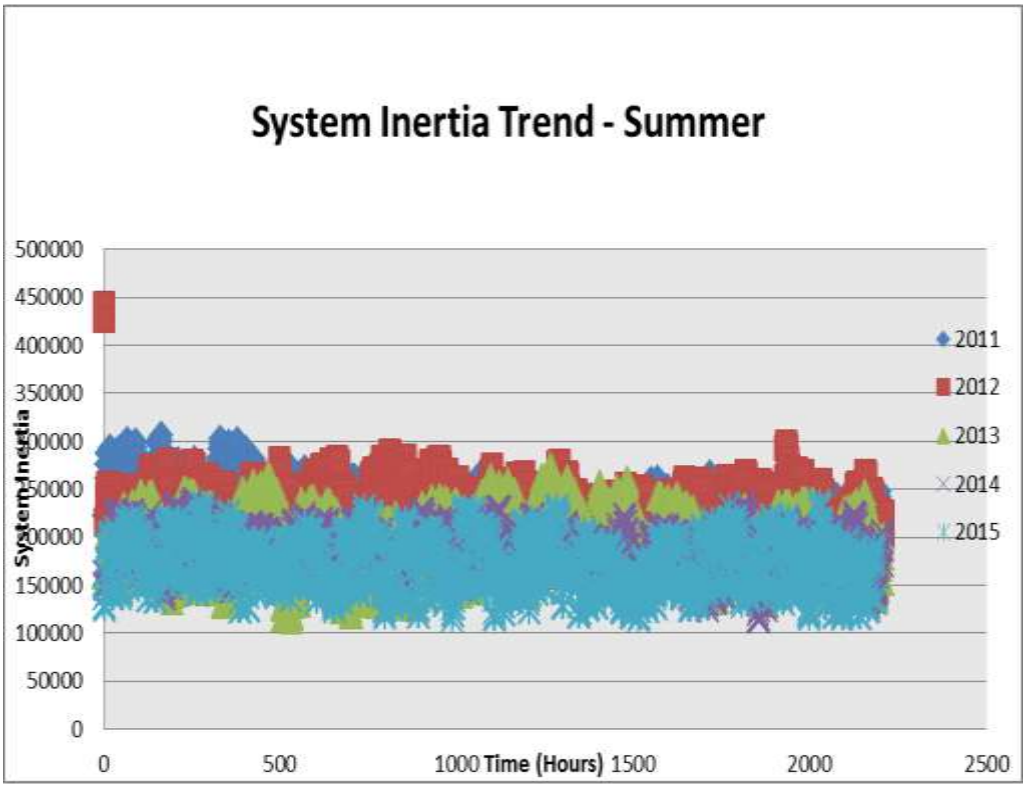


Figure 3

3.32 Please note that Table 5 was taken for SOF 2014 and Figures 2 and 3 were calculated using SOF 2014 data and are not current, but have been included since they were the evidence produced for the workgroup at the time. Figure 2 2015 data is not complete due to the data not being available at the time of the workgroup. For latest inertia and RoCoF updates see SOF 2016.

3 Workgroup Discussion

Frequency Ranges:

Overview of Existing Grid Code Requirements and Interaction with new RfG Requirements

3.1 The existing frequency ranges as defined in the Grid Code CC.6.1.3 are as follows:

Frequency Range	Requirement
51.5Hz - 52Hz	Operation for a period of at least 15 minutes is required each time the frequency is above 51.5Hz
51Hz – 51.5Hz	Operation for a period of at least 90 minutes is required each time the frequency is above 51Hz
49Hz – 51Hz	Continuous Operation is required
47.5Hz – 49Hz	Operation for a period of at least 90 minutes is required each time the frequency is below 49Hz
47Hz- 47.5Hz	Operation for a period of at least 20 seconds is required each time the frequency is below 47.5Hz

3.2 The frequency ranges as specified in RfG Article 13.1 (a) are as follows:

Synchronous area	**Frequency range**	**Time period for operation**
Great Britain	47.0 Hz – 47.5 Hz	20 seconds
	47.5 Hz – 48.5 Hz	90 minutes
	48.5 Hz – 49.0 Hz	To be specified by each TSO, but not less than 90 minutes
	49.0 Hz – 51.0 Hz	Unlimited
	51.0 Hz – 51.5 Hz	90 minutes
	51.5 Hz – 52.0 Hz	15 minutes

3.3 As can be seen from the above tables the requirements are almost identical, the only difference being that in RfG, in the 48.5Hz to 49Hz range, there is the option for the relevant TSO to specify a time greater but not less than 90 minutes which is the existing requirement in Grid Code.

3.4 The workgroup agreed to maintain the existing Grid Code requirements for frequency ranges.

3.5 In RfG Article 13.1(a)(ii) it states that: "*The relevant system operator, in coordination with the relevant TSO, and the power generating facility owner may agree on wider frequency ranges, longer minimum times for operation or specific requirements for combined frequency and voltage deviations to ensure the best use* *of the technical capabilities of a power generating module, if it is required to preserve or to restore system security;"*

3.6 The workgroup noted the interaction with the voltage ranges and contacted the voltage/reactive workgroup to ensure collaboration between groups on this issue. In response the voltage / reactive workgroup noted the interaction with Article 16(2)(a)(ii) which states "the relevant TSO may specify shorter periods of time during which power generating modules shall be capable of remaining connected to the network in the event of simultaneous overvoltage and underfrequency or simultaneous undervoltage and overfrequency.

3.7 It is therefore proposed to include additional wording in the Grid Code to cover this aspect. Additional legal text required to implement the RfG is included in Annex 4 of this report. All new text has the initials ECC (European Connection Conditions).

As stated in ECC.6.1.3, the **System Frequency** could rise to 52Hz or fall to 47Hz and the **System** voltage at the **Connection Point** could rise or fall within the values outlined in CC.6.1.4. **Each Power Generating Module** ~~**Generating Unit**~~, ~~**DC Converter**, or **OTSDUW Plant and Apparatus**, Power Park Module~~ or any constituent element must continue to operate within this **Frequency** range for at least the periods of time given in ECC.6.1.3 and voltage range as defined in ECC.6.1.4 unless **NGET** has agreed to any simultaneous overvoltage and underfrequency relays and/or simultaneous undervoltage and over frequency relays ~~or **Frequency** level relays and/or rate-of-change-of-**Frequency** relays~~ which will trip such **Power Generating Module**, ~~**Generating Unit**, **DC Converter**,~~ or **OTSDUW Plant and Apparatus**~~, **Power Park Module**~~ and any constituent element within this **Frequency** or voltage range, as specified under the **Bilateral Agreement**.

Limited Frequency Sensitive Mode – Over (LFSM-O)

Existing Grid Code Requirements

3.8 The current Grid Code Requirements for LFSM-O are specified in BC.3.7.2:

(a) Each Synchronised Genset (or DC Converter at a DC Converter Station) operating in a Limited Frequency Sensitive Mode which is producing Active Power is also required to reduce Active Power output in response to System Frequency when this rises above 50.4Hz. In the case of DC Converters at DC Converter Stations, the provisions of BC.3.7.7 are also applicable. For the avoidance of doubt, the provision of this reduction in Active Power output is not an Ancillary Service. Such provision is known as "Limited High Frequency Response".

(b) (i) The rate of change of Active Power output must be at a minimum rate of 2 per cent of output per 0.1Hz deviation of System Frequency above 50.4Hz.

(ii) The reduction in Active Power output must be continuously and linearly proportional as far as is practicable, to the excess of Frequency above 50.4Hz and must be provided increasingly with time over the period specified in (iii) below.

(iii) As much as possible of the proportional reduction in Active Power output must result from the frequency control device (or speed governor) action and must be achieved within 10 seconds of the time of the Frequency increase above 50.4Hz.

(iv) The residue of the proportional reduction in Active Power output which results from automatic action of the Genset (or DC Converter at a DC Converter Station) output control devices other than the frequency control devices (or speed governors) must be achieved within 3 minutes from the time of the Frequency increase above 50.4Hz.

(v) Any further residue of the proportional reduction which results from non-automatic action initiated by the Generator or DC Converter Station owner shall be initiated within 2 minutes, and achieved within 5 minutes, of the time of the Frequency increase above 50.4Hz.

(c) Each Genset (or DC Converter at a DC Converter Station) which is providing Limited High Frequency Response in accordance with this BC3.7.2 must continue to provide it until the Frequency has returned to or below 50.4Hz or until otherwise instructed by NGET.

RfG Definition Article 13.2

3.9 With regard to the limited frequency sensitive mode — overfrequency (LFSM-O), the following shall apply, as determined by the relevant TSO for its control area in coordination with the TSOs of the same synchronous area to ensure minimal impacts on neighbouring areas:

(a) the power generating module shall be capable of activating the provision of active power frequency response according to figure 1 at a frequency threshold and droop settings specified by the relevant TSO;

(b) instead of the capability referred to in paragraph (a), the relevant TSO may choose to allow within its control area automatic disconnection and reconnection of power generating modules of Type A at randomised frequencies, ideally uniformly distributed, above a frequency threshold, as determined by the relevant TSO where it is able to demonstrate to the relevant regulatory authority, and with the cooperation of power generating module owners, that this has a limited cross-border impact and maintains the same level of operational security in all system states;

(c) the frequency threshold shall be between 50.2 Hz and 50.5 Hz inclusive;

(d) the droop settings shall be between 2 % and 12 %;

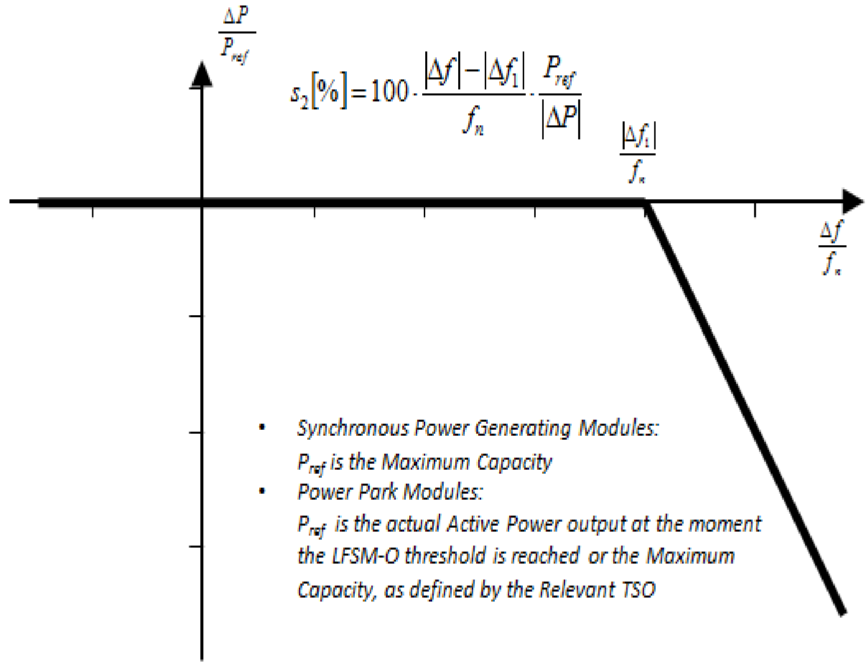
(e) the power generating module shall be capable of activating a power frequency response with an initial delay that is as short as possible. If that delay is greater than two seconds, the power generating facility owner shall justify the delay, providing technical evidence to the relevant TSO;

(f) the relevant TSO may require that upon reaching minimum regulating level, the power generating module be capable of either:

(i) continuing operation at this level; or

(ii) further decreasing active power output;

(g) the power generating module shall be capable of operating stably during LFSM-O operation. When LFSM-O is active, the LFSM-O setpoint will prevail over any other active power setpoints.



RfG Figure 1: active power frequency response capability of power generating modules in LFSM-O. P_{ref} is the reference active power to which ΔP is related and may be specified differently for synchronous power generating modules and power park modules. ΔP is the change in active power output from the power generating module. f_n is the nominal frequency (50 Hz) in the network and Δf is the frequency deviation in the network. At overfrequencies where Δf is above Δf_1, the power generating module has to provide a negative active power output change according to the droop S_2.

Implementation Issues

3.10 The values currently defined in Grid Code for frequency threshold and droop setting are compatible with the required ranges in RfG.

3.11 Activation time is not currently defined in Grid Code but RfG is specific that the activation time must not be greater than two seconds unless justified to the TSO with technical evidence. The process and detail of this justification is being clarified by workgroup GC0048. Therefore it was agreed that activation time should be as short as possible. If that delay is greater than two seconds, the power-generating facility owner shall justify the delay and that this should be written into the revised Grid Code text (see Annex 4 for legal drafting)

3.12 NGET in liaison with the workgroup has selected 50.4Hz as the frequency threshold for LFSM-O and Pref as the reference active power for droop calculations. NGET and the workgroup also interpret diagram RfG Fig 1 as a minimum requirement.

3.13 With reference to RfG Article 13.2(a) the issue is related to Type A generators and it states that the TSO will specify frequency threshold and droop settings. Article 13.2(b) is included as an alternative to article 13.2(a) and suggests automatic disconnection and reconnection of type A generators at randomised frequencies. The Workgroup forwarded this issue to the GC0048 work group and it was agreed by GC0048 that 13(2)(a) would be the most appropriate on the basis that it is more transparent and easier to manage.

3.14 Article 13.2 (g) states that:

"the power generating module shall be capable of operating stably during LFSM-O operation. When LFSM-O is active, the LFSM-O setpoint will prevail over any other active power setpoints.

This only becomes an issue if the generator is currently in FSM and is already responding to a high frequency. As demonstrated in Figure 4 below, this would involve a backward step change if taken literally and would not allow for FSM to continue after the 50.5Hz threshold."

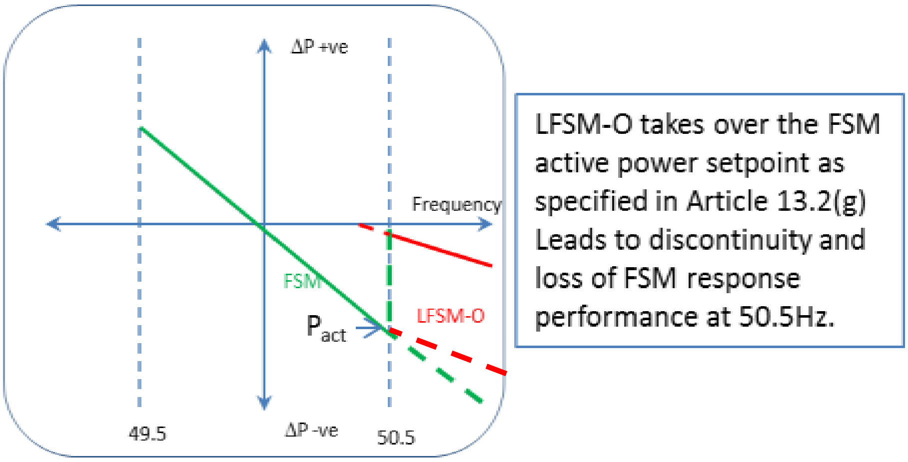


Figure 4 Demonstrates the unwanted interpretation of RfG LFSM-O, for the preferred interpretation see figure 11

The workgroup felt that this issue needed to be clarified with ENTSOE and a paper was prepared and submitted. The workgroup would prefer that if a generator is already in FSM then it should remain there regardless of system frequency. We need to define a new term for the point at which the LFSM-O trigger activates as $P_{act.}$ For both synchronous and non-synchronous we are defining P_{ref} as P_{max} (maximum capacity) and therefore this new definition of P_{act} is required to enable LFSM-O to operate seamlessly. After the 50.5Hz threshold is reached, plant in FSM should continue at best endeavours but as a minimum at LFSM-O requirements.

In the past there has often been confusion that the requirements for LFSM-O have been defined in BC.3.7.2 rather than in the connection conditions. It was therefore decided by the workgroup to move these requirements from BC3 into the connection conditions (CC.6.3.7 which will become ECC.6.3.7). It is also worth noting that RfG applies to all power generating modules of Type A and above (ie 800W plus) whereas BC.3.7.2 only applies to gensets which is any plant which is part of a large power station or connected directly to the transmission system.

DMOL – Design Minimum Operation Level

3.15 The Workgroup assumes minimum regulating level (as defined in RfG) is the same as designed minimum operating level (DMOL as defined in the GB Grid Code). The references for DMOL and minimum regulating level in both documents were cross-referenced and no apparent conflict was uncovered.

3.16 The following references were found for DMOL in the Grid Code:

Glossary
PC.A.5.5.1 – MW loading points at which data is required
CC.6.3.7 – frequency control
CC.A.3.2 – plant operating range
CC.A.3.3 – minimum frequency response requirement profile
OC5.A.2.8.6- frequency testing schedules
OC5.A.2.8.8 - frequency testing schedules
OC5.A.3.6.6 - frequency testing schedules
OC5.A.3.6.8 - frequency testing schedules
OC5.A.4.5.6- frequency testing schedules
OC5.A.4.5.8 - frequency testing schedules
BC3.7.1 – plant in frequency sensitive mode instructed to provide high frequency response
BC3.7.3 – plant operation to below minimum generation
PC.A.5.5 – Governor Droop and Response

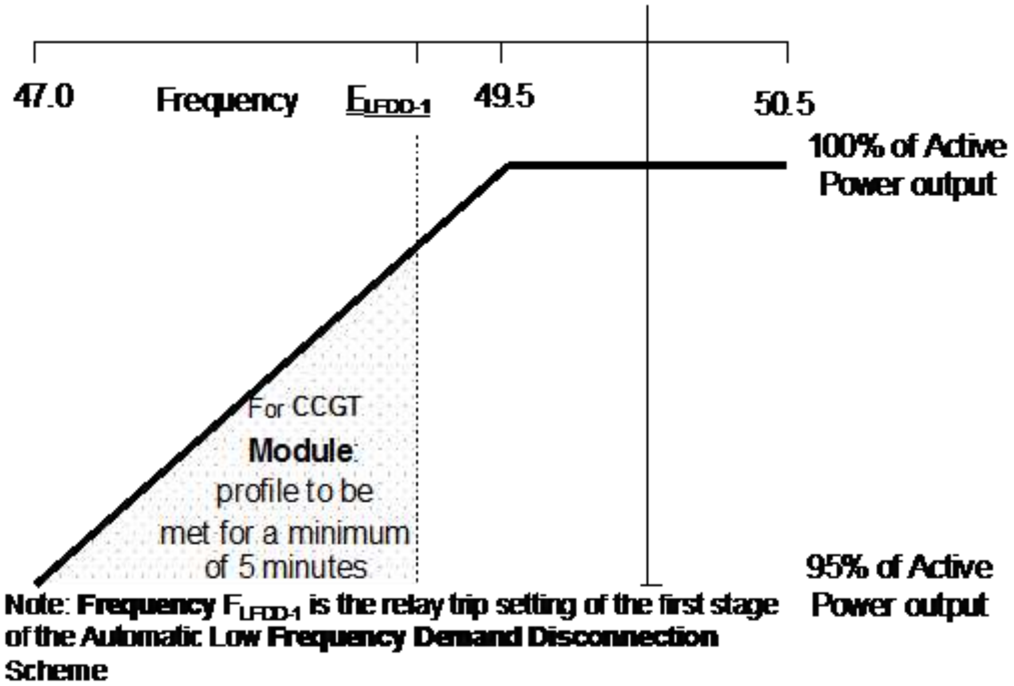
3.17 The following references were found for minimum regulating level in RfG:

Article 2 Definitions
Article 13.2(f) – LFSM_O
Article 15.2(d)(i) – FSM
Article 15.5(a)(vi) – black start
Article 45.3(a) – compliance tests for type ‘C’ synchronous
Article 48.4(a) – compliance tests for type ‘C’ power park modules
Article 51.2(b) – compliance simulations for type ‘B’ synchronous
Article 54.2(b) - compliance simulations for type ‘B’ power park modules

3.18 The workgroup proposes that since DMOL is essentially the same as minimum regulating level, the simplest way to address the issue of different terms used in RfG and Grid Code is to include a new entry in the definitions stating that DMOL is in effect minimum regulating level.

Maintenance of Constant Active Power & Power Output with Falling Frequency

Grid Code Requirement CC.6.3.3



GC Figure 2

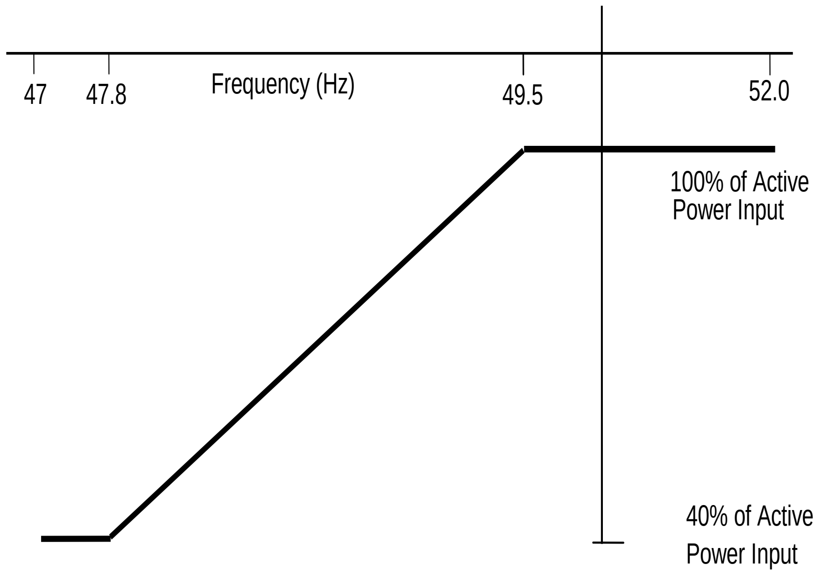
Each **Generating Unit**, **DC Converter** (including an **OTSDUW DC Converter**), **Power Park Module** and/or **CCGT Module** must be capable of:

(a) continuously maintaining constant **Active Power** output for **System Frequency** changes within the range 50.5 to 49.5 Hz; and

(b) (subject to the provisions of CC.6.1.3) maintaining its **Active Power** output at a level not lower than the figure determined by the linear relationship shown in Figure 2 for **System Frequency** changes within the range 49.5 to 47 Hz, such that if the **System Frequency** drops to 47 Hz the **Active Power** output does not decrease by more than 5%. In the case of a **CCGT Module**, the above requirement shall be retained down to the **Low Frequency Relay** trip setting of 48.8 Hz, which reflects the first stage of the Automatic Low **Frequency Demand Disconnection** scheme notified to **Network Operators** under OC6.6.2. For **System Frequency** below that setting, the existing requirement shall be retained for a minimum period of 5 minutes while **System Frequency** remains below that setting, and special measure(s) that may be required to meet this requirement shall be kept in service during this period. After that 5 minutes period, if **System Frequency** remains below that setting, the special measure(s) must be discontinued if there is a materially increased risk of the **Gas Turbine** tripping. The need for special measure(s) is linked to the inherent **Gas Turbine Active Power** output reduction caused by reduced shaft speed due to falling **System Frequency**.

(c) For the avoidance of doubt in the case of a **Generating Unit** or **Power Park Module** (or **OTSDUW DC Converters** at the **Interface Point**) using an **Intermittent Power Source** where the mechanical power input will not be constant over time, the requirement is that the **Active Power** output shall be independent of **System Frequency** under (a) above and should not drop with **System Frequency** by greater than the amount specified in (b) above.

(d) A **DC Converter Station** must be capable of maintaining its **Active Power** input (iewhen operating in a mode analogous to **Demand**) from the **National Electricity Transmission System** (or **User System** in the case of an **Embedded DC Converter Station**) at a level not greater than the figure determined by the linear relationship shown in Figure 3 for **System Frequency** changes within the range 49.5 to 47 Hz, such that if the **System Frequency** drops to 47.8 Hz the **Active Power** input decreases by more than 60%.



GC Figure 3

(e) At a **Large Power Station**, in the case of an **Offshore Generating Unit**, **Offshore Power Park Module**, **Offshore DC Converter** and **OTSDUW DC Converter**, the **Generator** shall comply with the requirements of CC.6.3.3. **Generators** should be aware that Section K of the **STC** places requirements on **Offshore Transmission Licensees** which utilise a **Transmission DC Converter** as part of their **Offshore Transmission System** to make appropriate provisions to enable **Generators** to fulfil their obligations.

(f) In the case of an **OTSDUW DC Converter** the **OTSDUW Plant and Apparatus** shall provide a continuous signal indicating the real time frequency measured at the **Interface Point** to the **Offshore Grid Entry Point**.

RfG Requirements Article 13.3, 13.4 & 13.5

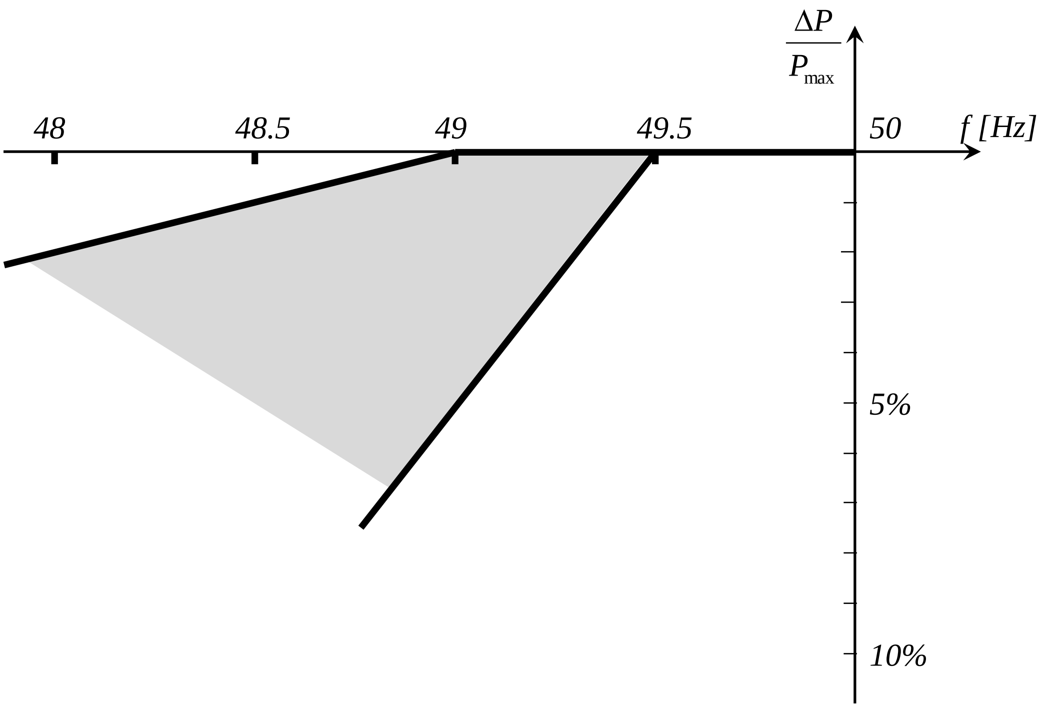
1. The power generating module shall be capable of maintaining constant output at its target active power value regardless of changes in frequency, except where output follows the changes specified in the context of paragraphs 2 and 4 of this Article or points (c) and (d) of Article 15(2) as applicable.
2. The relevant TSO shall specify admissible active power reduction from maximum output with falling frequency in its control area as a rate of reduction falling within the boundaries, illustrated by the full lines in Figure 2:

   (a) below 49 Hz falling by a reduction rate of 2 % of the maximum capacity at 50 Hz per 1 Hz frequency drop;

   (b) below 49.5 Hz falling by a reduction rate of 10 % of the maximum capacity at 50 Hz per 1 Hz frequency drop.
3. The admissible active power reduction from maximum output shall:

   (c) clearly specify the ambient conditions applicable;

   (d) take account of the technical capabilities of power generating modules.



RfG Figure 2: Maximum power capability reduction with falling frequency. The diagram represents the boundaries in which the capability can be specified by the relevant TSO.

Comparison between Grid Code and RfG

3.19 The Grid Code definitions for Maintenance of Constant Active Power and Power Output with Falling Frequency are broadly similar to those specified in RfG. Figure 5 below demonstrates that current Grid Code sits within the envelope defined in RfG and we interpret it to continue to 47Hz (see clause ECC.6.1.2 in Annex 4)

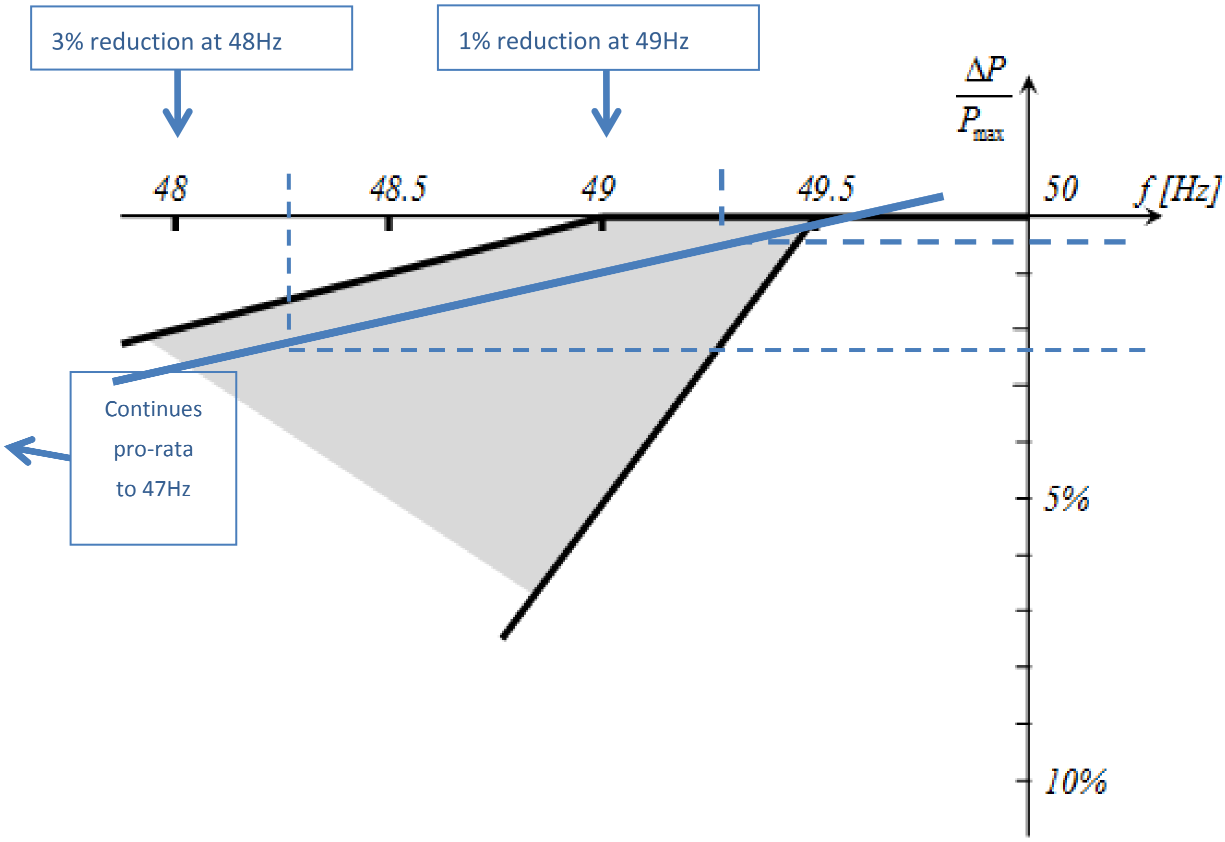


Figure 5

3.20 In addition, CC.6.3.3 does not currently refer to ambient conditions. Ambient conditions are defined only in the Operating Code OC.2.4.2.1(h) (Data requirements), OC.5.5.4 (testing and monitoring assessments and OC5.A.2.9.1 (Compliance with CC.6.3.3 Functionality Test). The workgroup agreed to add the existing ambient condition requirements currently in OC5 into CC.6.3.3 which will add clarity in the Grid Code as the suggested text moves all aspects of this requirement together in the code.

Limited Frequency Sensitive Mode – Under (LFSM-U)

Current Grid Code Definition for LFSM-U

There is currently no definition for LFSM-U in the Grid Code.

RfG Definition of LFSM-U Article 15.2(c)

Under the RfG Code, limited frequency sensitive mode - underfrequency (LFSM-U) is defined under the Glossary and Definitions as “a power-generating module or HVDC system operating mode which will result in active power output increase in response to a change in system frequency below a certain value.

In addition to paragraph 2 of Article 13, the following requirements shall apply to type C power generating modules with regard to limited frequency sensitive mode – underfrequency (LFSM-U):

(i) the power generating module shall be capable of activating the provision of active power frequency response at a frequency threshold and with a droop specified by the relevant TSO in coordination with the TSOs of the same synchronous area as follows:

- the frequency threshold specified by the TSO shall be between 49.8 Hz and 49.5 Hz inclusive;
- the droop settings specified by the TSO shall be in the range 2 – 12 %.

This is represented graphically in Figure 4;

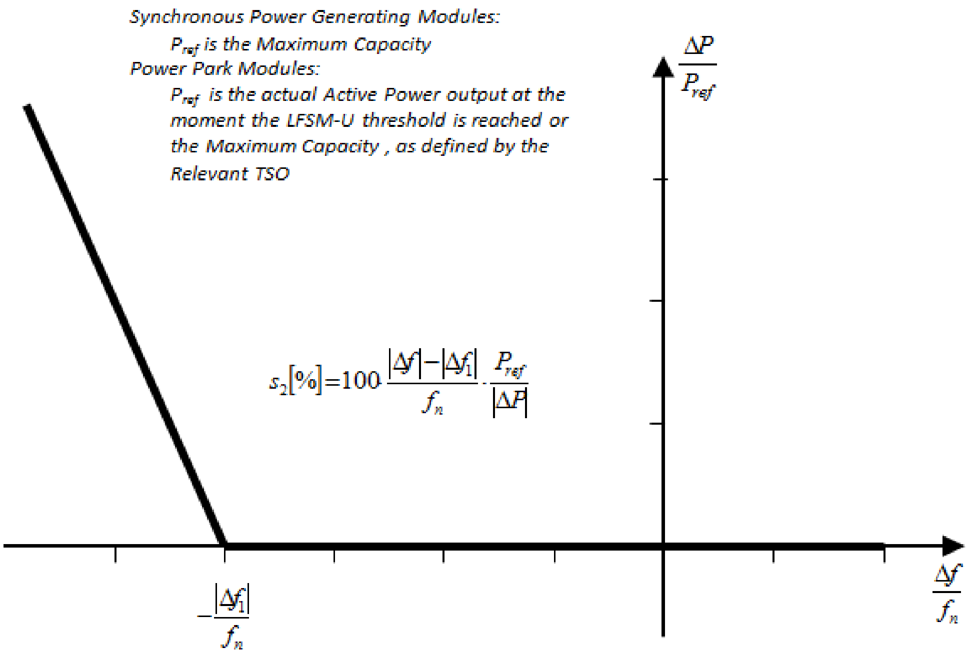
(ii) the actual delivery of active power frequency response in LFSM-U mode shall take into account:

- ambient conditions when the response is to be triggered;
- the operating conditions of the power generating module, in particular limitations on operation near maximum capacity at low frequencies and the respective impact of ambient conditions according to paragraphs 4 and 5 of Article 13; and
- the availability of the primary energy sources.

(iii) the activation of active power frequency response by the power generating module shall not be unduly delayed. In the event of any delay greater than two seconds, the power generating facility owner shall justify it to the relevant TSO;

(iv) in LFSM-U mode the power generating module shall be capable of providing a power increase up to its maximum capacity;

(v) stable operation of the power generating module during LFSM-U operation shall be ensured;



RfG Figure 4: active power frequency response capability of power generating modules in LFSM-U. P_{ref} is the reference active power to which ΔP is related and may be specified differently for synchronous power generating modules and power park modules. ΔP is the change in active power output from the power generating module. f_n is the nominal frequency (50 Hz) in the network and Δf is the frequency deviation in the network. At underfrequencies where Δf is below Δf_1 the power generating module has to provide a positive active power output change according to the droop S_2.

Comparison of RfG Requirement with Current Practice

3.21 The RfG allows the TSO to select values for frequency threshold and droop within ranges (49.8Hz – 49.5Hz and 2-12% respectively) and defines the activation time at no greater than 2s.

3.22 The workgroup's view of LFSM-U is that it is a function that will be very rarely utilised and its sole purpose is to try to prevent low frequency demand disconnection should the frequency fall be greater than can be managed by primary and secondary response. LFSM-U should oblige any part-loaded plant which is not in frequency sensitive mode (FSM) to respond to the best of its abilities. In other words, utilise spare capacity from any available generating plant as a last resort.

3.23 To avoid any interaction with FSM, the frequency threshold for LFSM-U is proposed to be set at 49.5Hz. By setting the threshold for LFSM-U at the required limit, this also takes into consideration the fact that the plant in LFSM-U will not be expected and therefore be prepared to have to respond. In other words National Grid will continue to schedule reserve and response as it currently does today and will not rely on LFSM-U capability to maintain frequency within statutory limits. LFSM-U would only be supplied when initiated by system conditions and from plant which has headroom. The droop setting is proposed to be set at 10%. The initial activation delay time is set in RfG at no more than 2s unless technically justified to the TSO. The GC0048 Workgroup is in the process of clarifying exactly what "justify to the TSO" would entail. The value of droop is based on that used for LFSM-O which is also set at 10%. Since there is no requirement for the SO to hold this capability, generators would not be remunerated for it. A new compliance test will need to be developed for LFSM-U similar to that for LFSM-O.

Areas of Concern

3.24 NGET were asked to demonstrate the effectiveness/value (if any) of LFSM-U. It was felt that there should be some demonstrable benefit to an obligation which would potentially incur cost to the generator. Note that the study was undertaken with a simulated loss of 2000MW since it is looking at an abnormal loss which would not be secured by normal primary and secondary response.

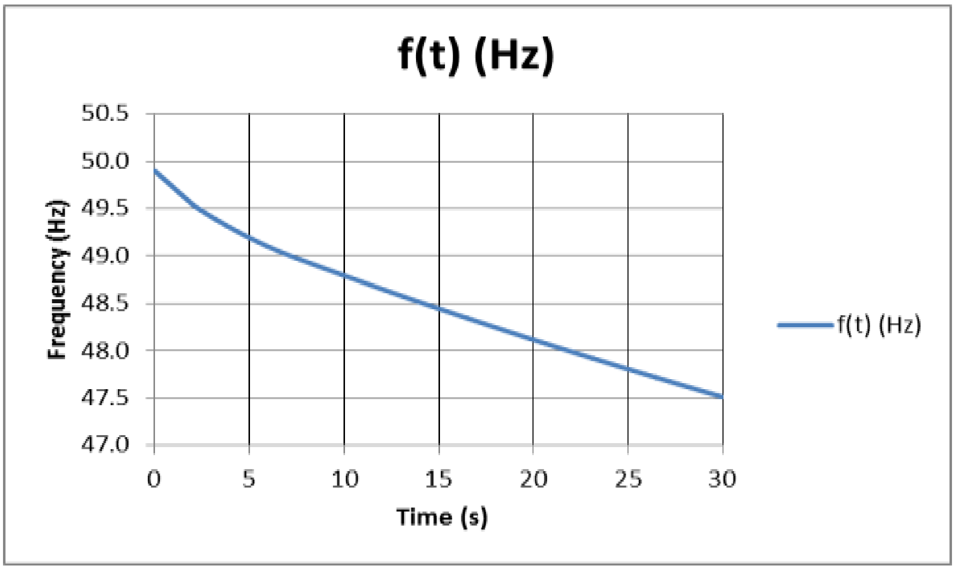


Figure 6: demonstrates the effect on frequency of a 2000MW loss at low system demand without LFSM-U.

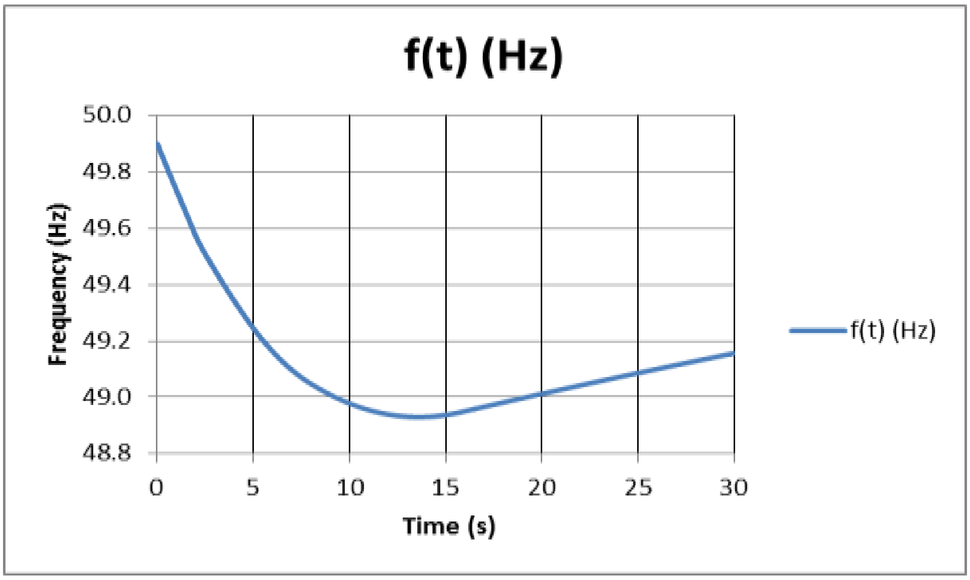


Figure 7: demonstrates the effect on frequency of a 2000MW loss at low system demand with LFSM-U.

Table of Data				
Tot. Dem. (MW)	Stat. (MW)	Prim. (MW)	Sec. (MW)	LFSM-U (MW)
24424	258	995	152	1000
29424	258	761	296	1000
34424	258	510	454	1000
39424	258	247	620	1000
44424	258	-32	799	1000

Table 6 displays the data used in Figure 7

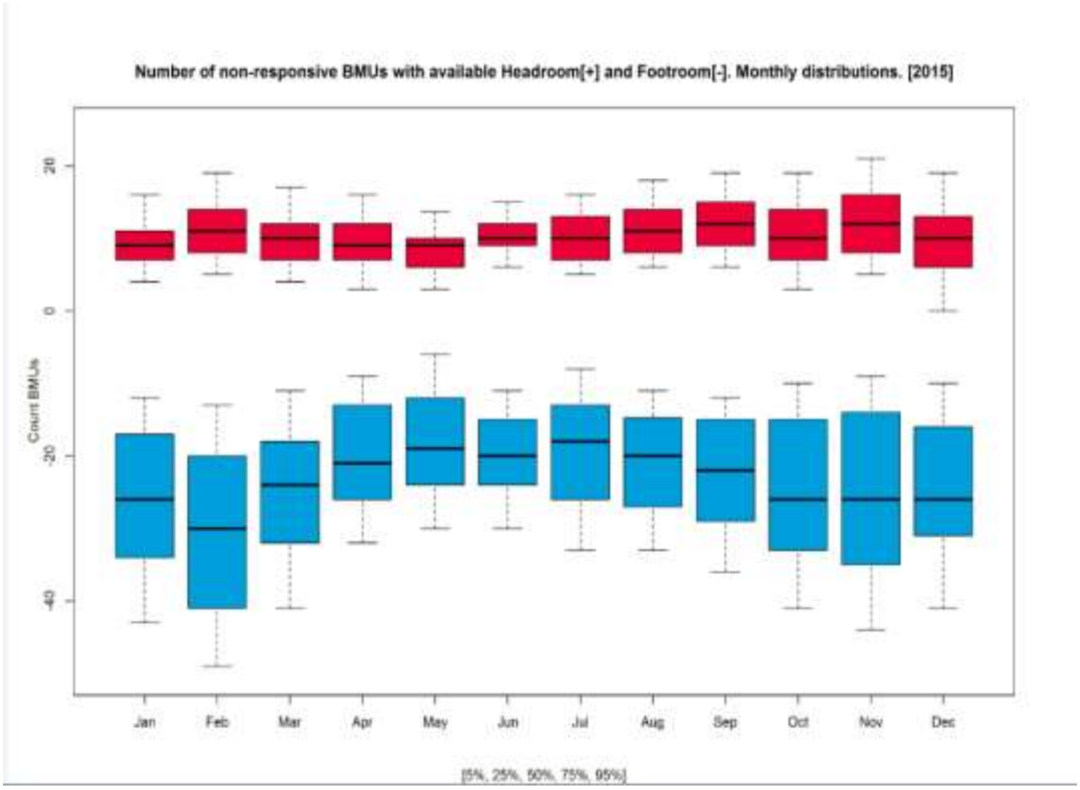


Figure 8: demonstrates the number of non-responsive BMUs (ie not in FSM mode) with available headroom and footroom on a monthly basis for 2015

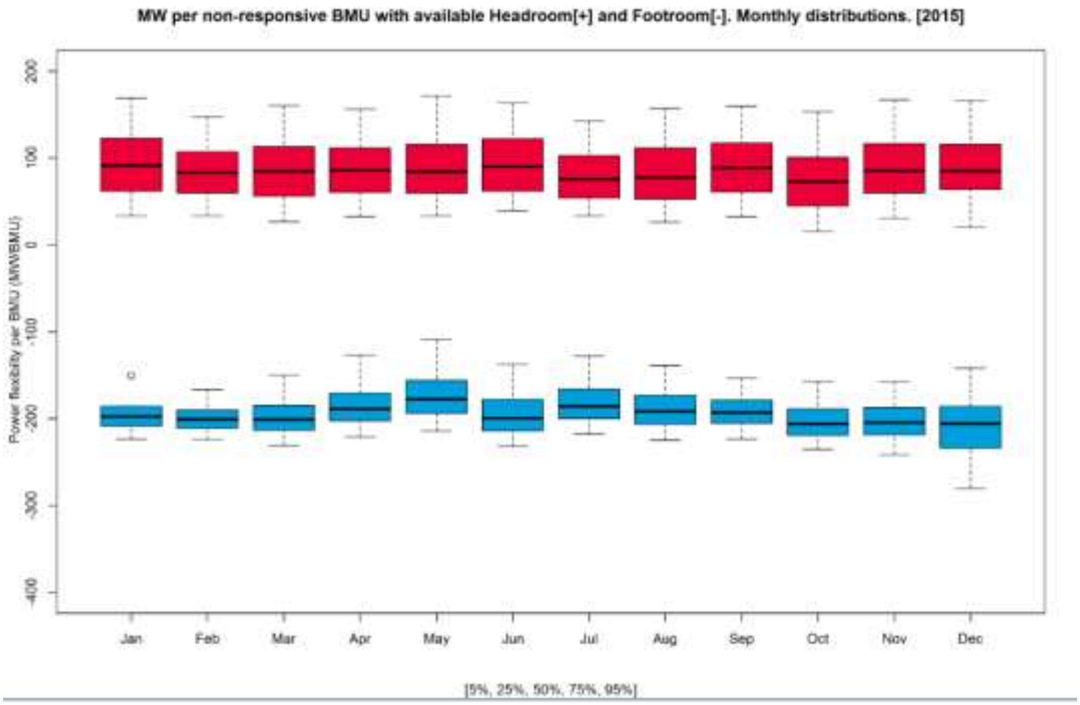


Figure 9 demonstrates the MW per non-responsive BMU with available headroom and footroom on a monthly basis

3.25 As can be seen there is a benefit to having LFSM-U even at low demands, studies showed that at higher demands the frequency could be contained to within the 49.2Hz threshold. This was based on an assumption of 1000MW of LFSM-U response (ie 100MW on 10 machines taken from the attached monthly distribution graphs – figures 8 and 9).

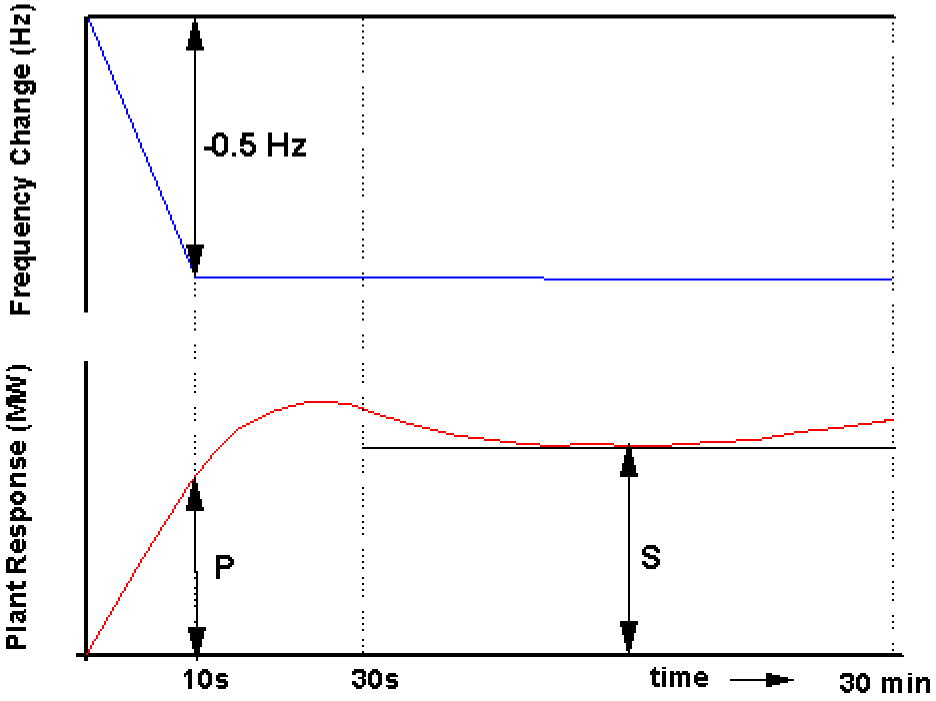
3.26 NGET's and the majority of the workgroup felt that LFSM-U should be an obligation since an incident of this nature would be out with the criteria that NGET would secure the system against, it should not incur a cost to NGET. A minority of the workgroup felt that since fulfilling this requirement results in an automatic increase in power and would add cost to the generators due to increased fuel consumption and stress on plant, then this was a commercial service which should be instructed and paid for. It was agreed that this issue was outside the remit of the workgroup and should be taken up with NGET Commercial Services.

Frequency Sensitive Mode (FSM)

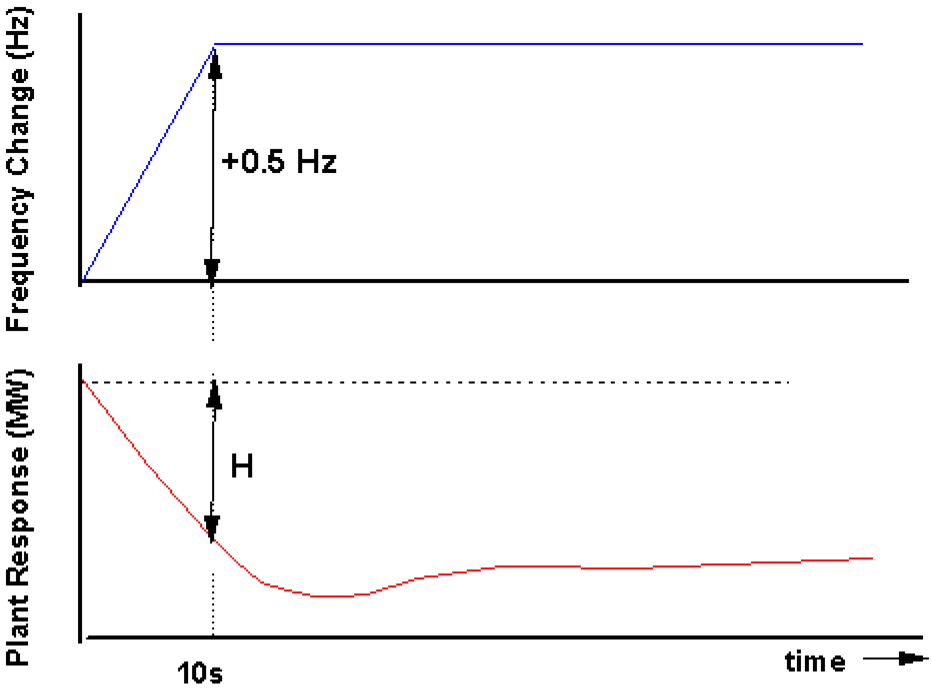
Current Grid Code Obligation

3.27 Frequency Sensitive Mode (FSM) is defined in the Grid Code as "A Genset operating mode which will result in result in Active Power output changing, in response to a change in System Frequency, in a direction which assists in the recovery to Target Frequency, by operating so as to provide Primary Response and/or Secondary Response and/or High Frequency Response." In addition there are various definitions referring to FSM such as CC.A.3.2 and CC.A.3.3 below which specify the action required for primary and secondary response.

CC.A.3.2



CC.A.3.3



Primary Response is defined as:

Primary Response The automatic increase in **Active Power** output of a **Genset** or, as the case may be, the decrease in **Active Power Demand** in response to a **System Frequency** fall. This increase in **Active Power** output or, as the case may be, the decrease in **Active Power Demand** must be in accordance with the provisions of the relevant **Ancillary Services Agreement** which will provide that it will be released increasingly with time over the period 0 to 10 seconds from the time of the start of the **Frequency** fall on the basis set out in the **Ancillary Services Agreement** and fully available by the latter, and sustainable for at least a further 20 seconds. The interpretation of the **Primary Response** to a -0.5Hz . The interpretation of the Primary Response to a -0.5Hz frequency change is shown diagrammatically in Figure CC.A.3.2.

Secondary Response: The automatic increase in **Active Power** output of a **Genset** or, as the case may be, the decrease in **Active Power Demand** in response to a System Frequency fall. This increase in **Active Power** output or, as the case may be, the decrease in **Active Power Demand** must be in accordance with the provisions of the relevant **Ancillary Services Agreement** which will provide that it will be fully available by 30 seconds from the time of the start of the **Frequency** fall and be sustainable for at least a further 30 minutes. The interpretation of the **Secondary Response** to a -0.5Hz frequency change is shown diagrammatically in Figure CC.A.3.2.

RfG Definition of FSM – Article 15.2(d)

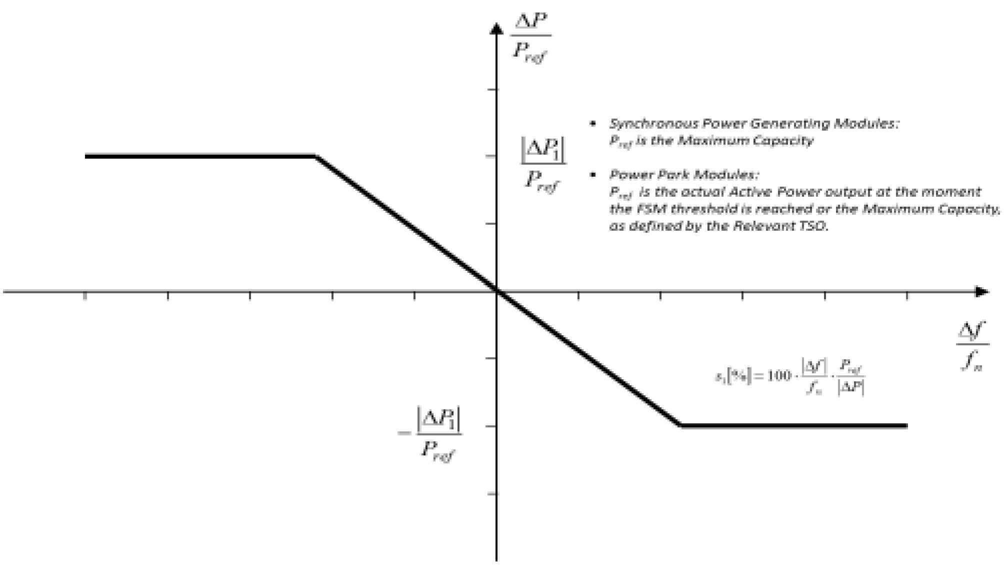
(d) in addition to point (c) of paragraph (2), the following shall apply cumulatively when frequency sensitive mode ('FSM') is operating:

(i) the power generating module shall be capable of providing active power frequency response in accordance with the parameters specified by each relevant TSO within the ranges shown in Table 4. In specifying those parameters, the relevant TSO shall take account of the following facts:

- in case of overfrequency, the active power frequency response is limited by the minimum regulating level;
- in case of underfrequency, the active power frequency response is limited by maximum capacity;
- the actual delivery of active power frequency response depends on the operating and ambient conditions of the power generating module when this response is triggered, in particular limitations on operation near maximum capacity at low frequencies according to paragraphs 4 and 5 of Article 13 and available primary energy sources;

Parameters		Ranges
Active power range related to maximum capacity	$\frac{\|\Delta P_1\|}{P_{\max}}$	1.5 – 10 %
Frequency response insensitivity	$\|\Delta f_i\|$	10 – 30 mHz
	$\frac{\|\Delta f_i\|}{f_n}$	0.02 – 0.06 %
Frequency response deadband		0 – 500 mHz
Droop s_1		2 – 12 %

RfG Table 4: Parameters for active power frequency response in FSM (explanation for Figure 5)



RfG Figure 5: Active power frequency response capability of power generating modules in FSM illustrating the case of zero deadband and insensitivity. P_{ref} is the reference active power to which ΔP is related. ΔP is the change in active power output from the power generating module. f_n is the nominal frequency (50 Hz) in the network and Δf is the frequency deviation in the network.

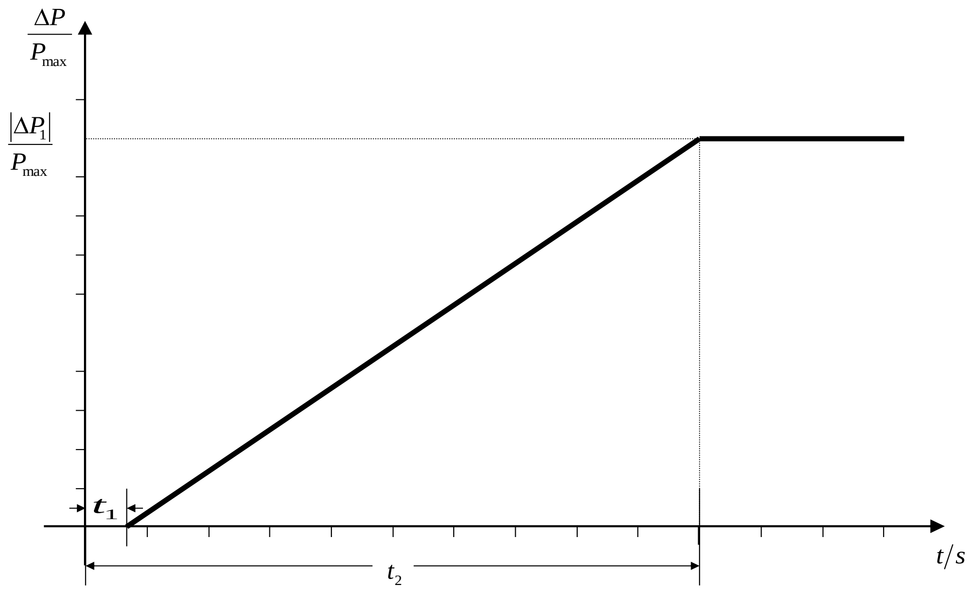
(ii) the frequency response deadband of frequency deviation and droop must be able to be reselected repeatedly;

(iii) in the event of a frequency step change, the power generating module shall be capable of activating full active power frequency response, at or above the full line shown in Figure 6 in accordance with the parameters specified by each TSO (which shall aim at avoiding active power oscillations for the power generating module) within the ranges given in Table 5. The combination of choice of the parameters specified by the TSO shall take possible technology-dependent limitations into account;

(iv) The initial activation of active power frequency response required shall not be unduly delayed.

If the delay in initial activation of active power frequency response is greater than two seconds, the power generating facility owner shall provide technical evidence demonstrating why a longer time is needed.

For power generating modules without inertia, the relevant TSO may specify a shorter time than two seconds. If the power generating facility owner cannot meet this requirement they shall provide technical evidence demonstrating why a longer time is needed for the initial activation of active power frequency response;



RfG Figure 6: Active power frequency response capability. P_{max} is the maximum capacity to which ΔP relates. ΔP is the change in active power output from the power generating module. The power generating module has to provide active power output ΔP up to the point ΔP_1 in accordance with the times t_1 and t_2 with the values of ΔP_1, $t_1$and t_2 being specified by the relevant TSO according to Table 5. t_1 is the initial delay. t_2 is the time for full activation.

(v) the power generating module shall be capable of providing full active power frequency response for a period of between 15 and 30 minutes as specified by the relevant TSO. In specifying the period, the TSO shall have regard to active power headroom and primary energy source of the power generating module;

(vi) within the time limits laid down in point (v) of paragraph (2) (d), active power control must not have any adverse impact on the active power frequency response of power generating modules;

(vii) the parameters specified by the relevant TSO in accordance with paragraphs (i), (ii), (iii) and (v) shall be notified to the relevant regulatory authority. The modalities of that notification shall be specified in accordance with the applicable national regulatory framework;

Parameters	Ranges or values
Active power range related to maximum capacity (frequency response range) $\frac{\lvert\Delta P_1\rvert}{P_{\max}}$	1.5 – 10 %
For power generating modules with inertia, the maximum admissible initial delay t_1 unless justified otherwise in line with Article 15 (2) (d) (iv)	2 seconds
For power generating modules without inertia, the maximum admissible initial delay t_1 unless justified otherwise in line with Article 15 (2) (d) (iv)	as specified by the relevant TSO.
Maximum admissible choice of full activation time t_2, unless longer activation times are allowed by the relevant TSO for reasons of system stability	30 seconds

RfG Table 5: Parameters for full activation of active power frequency response resulting from frequency step change (explanation for Figure 6).

Comparison of Grid Code versus RfG:

3.28 The key change is that the compliance of new generators is based on step response not ramp.

3.29 The permissible ranges for Active Power, deadband and droop are consistent with current Grid Code parameters.

3.30 There was a need to define insensitivity and deadband. The following code amendment proposals were agreed by the workgroup:

Existing CC.6.3.7 (c) (iii)

in the case of all **Generating Units, DC Converter** or **Power Park Module** other than the **Steam Unit** within a **CCGT Module** the **Frequency** control device (or speed governor) deadband should be no greater than 0.03Hz (for the avoidance of doubt, ±0.015Hz). In the case of the **Steam Unit** within a **CCGT Module**, the speed **Governor Deadband** should be set to an appropriate value consistent with the requirements of CC.6.3.7(c)(i) and the requirements of BC3.7.2 for the provision of **Limited High Frequency Response**;

Update to provide RfG implementation whilst retaining GC definition Governor Deadband for existing plant

in the case of all **Generating Units, DC Converter** or **Power Park Module** other than the **Steam Unit** within a **CCGT Module** the **Frequency** **Response Insensitivity** of the **Frequency** control device (or speed **Governor** should be no greater than 0.03Hz (for the avoidance of doubt, ±0.015Hz). In the case of mechanical governor systems the **Governor Deadband** is the same as **Frequency Response Insensitivity**. In the case of the **Steam Unit** within a **CCGT Module**, the **Frequency Response Insensitivity** of the **Frequency** control device (or speed governor) should be set to an appropriate value consistent with the requirements of CC.6.3.7(c)(i) and the requirements of BC3.7.2 for the provision of **Limited High Frequency Response**;

3.31 This text has been discussed and agreed at the workgroup.

3.32 Similar to LFSM-U, the maximum admissible initial delay is set at no greater than 2s for plant with inertia (again unless otherwise justified).

3.33 The maximum admissible initial delay (t_1 of RfG Figure 6) is set at 2 seconds for plant with inertia and for plant without inertia a value is to be specified by the TSO which may be a shorter time than two seconds.

3.34 Based on previous work in GC0022 NGET was minded to select a value for t_1 of 1 second for plant without inertia. However if the power generating facility owner cannot meet this requirement they shall provide technical evidence demonstrating why a longer time is needed for the initial activation of active power frequency response.

3.35 NGET was asked to demonstrate the benefit of a delay of 1s from plant without inertia. The graph figure 10 shows on its horizontal axis infeed loss levels in MW and on the vertical axis the amount of primary response which requires to be held to ensure all infeed losses of 1000MW or less are contained within a frequency drop above 49.5Hz and infeed losses above 1000MW are contained within a frequency drop of greater than 49.2Hz. The red curve shows the amount of reserve holding required if all generating units start to respond after 2s, the blue shows the amount of reserve holding if all the generating units start to respond after 1 second, the green graph curve is half the units responding after 1 second and the other half after 2s and finally the purple trace is 10% of units responding after 1 second with the rest after 2s:

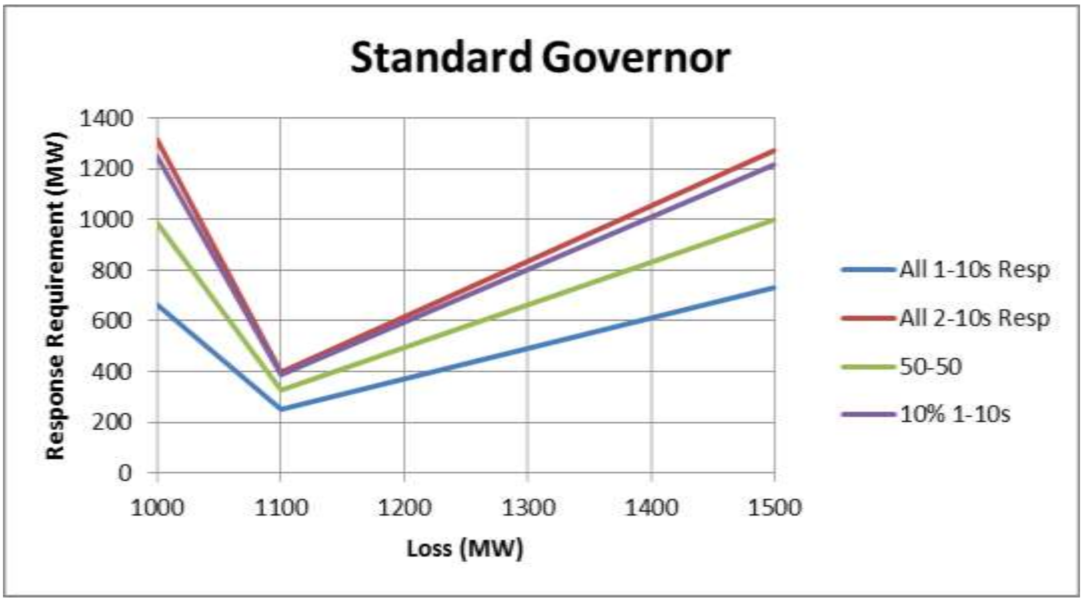


Figure 10

3.36 The requirement to maintain system frequency is more onerous for a 1000MW or below loss, hence the drop in frequency response requirement after 1000MW on the graph. Losses over 1000MW need to be contained above 49.2Hz as opposed to above 49.5Hz below 1000MW.

		Total System Demand = 24.4 GW			
	Loss (MW)	All 1-10s Resp	All 2-10s Resp	50-50	10% 1-10s
	1000	664	1318	991	1252.6
	1100	251	400	325.5	385.1
	1500	730	1271	1000.5	1216.9
Note:	1000 MW loss must be contained above 49.5 Hz.				
	1500 MW loss must be contained above 49.2 Hz.				

Table 7: Data behind the graph in Figure 10

3.37 Following workgroup discussions continued from GC0022 and detailed in section 2 with regard to diminishing system inertia, the workgroup agreed that the delay time for plant without inertia should be 1s and therefore this is what is proposed.

Areas of Concern

3.38 RfG states at the beginning of Article 15.2(d) that: in addition to point (c) of paragraph (2), the following shall apply cumulatively when frequency sensitive mode ('FSM') is operating. The word “cumulatively” caused some concerns. The phrase could be interpreted in more than one way. Some interpretations would require the installation of complex/expensive control systems and could potentially lead to a reduction in the effectiveness of FSM.

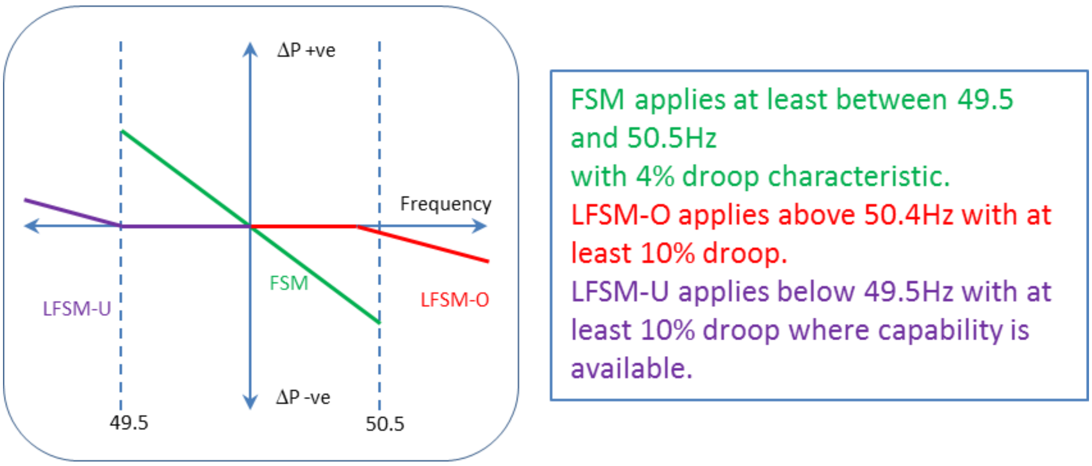


Figure 11: demonstrates the preferred and agreed interpretation of RfG 15.2(d) and the dashed lines are indicative of the range of responses which would be acceptable for plant in FSM.

3.39 The workgroup’s interpretation is that all plant in FSM should operate according to its low frequency settings. We have selected a 49.5Hz threshold for LFSM_U to avoid interacting with FSM. This would not preclude a plant continuing to operate in FSM mode to a droop of 3-5% below the 49.5Hz threshold. Once the 49.5 threshold is reached LFSM_U requirement activates but only if the plant has headroom and the capability to increase its output.

3.40 The workgroup does not believe that the intention of ENTSOE was for plant in FSM mode to switch to LFSM_U operation at the selected trigger point (49.5Hz) as this would not be beneficial to the system. The workgroup recommends for plant in FSM to continue following the setting for FSM even below the 49.5Hz LFSM_U trigger if the plant still has capability. A 10% droop below 49.5Hz is the minimum compliant response.

Monitoring

Existing Grid Code Definition

3.41 Real time monitoring requirements are defined in Grid Code CC6.5.6.

CC.6.5.6

Operational Metering

(a) **NGET** shall provide system control and data acquisition (SCADA) outstation interface equipment. The **User** shall provide such voltage current. **Frequency Active Power** and **Reactive Power** measurement outputs and plant status indications and alarms to the Transmission SCADA outstation interface equipment as required by **NGET** in accordance with the terms of the **Bilateral Agreement**.

3.42 In addition OC5.4.1(c) states "NGET will monitor the performance of (c) the provision by Users of Ancillary Services which they are required or have agreed to provide.

3.43 The requirement for Ancillary Services Monitoring in defined in TS 3.24.95 (RES) http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/Electrical-Standards-Documents/

RfG Criteria – Article 15.2(g)

with regard to real-time monitoring of FSM:

(i) to monitor the operation of active power frequency response, the communication interface shall be equipped to transfer in real time and in a secured manner from the power generating facility to the network control centre of the relevant system operator or the relevant TSO, at the request of the relevant system operator or the relevant TSO, at least the following signals:

- status signal of FSM (on/off);
- scheduled active power output;
- actual value of the active power output;
- actual parameter settings for active power frequency response;
- droop and deadband;

(ii) the relevant system operator and the relevant TSO shall specify additional signals to be provided by the power generating facility by monitoring and recording devices in order to verify the performance of the active power frequency response provision of participating power generating modules.

Comparison of GC with RfG

3.44 All aspects of monitoring are now being covered by the system management group GC0048.

Rate of Change of Frequency (RoCoF) Withstand Capability

Grid Code Definition for RoCoF Withstand Capability

3.45 There is currently no definition for RoCoF withstand capability in the Grid Code.

RfG Definition of RoCoF Withstand Capability – Article 13.1(b)

(b) With regard to the rate of change of frequency withstand capability, a power generating module shall be capable of staying connected to the network and operate at rates of change of frequency up to a value specified by the relevant TSO, unless disconnection was triggered by rate-of-change-of-frequency-type loss of mains protection. The relevant system operator, in coordination with the relevant TSO, shall specify this rate-of-change-of-frequency-type loss of mains protection.

Implications of RfG Implementation

3.46 National Grid was asked by the workgroup to provide a suggested value of RoCoF withstand capability which it felt would enable it as System Operator to manage the system frequency in an efficient manner. This work was carried out in line with preparation of the System Operability Framework (SOF) document for 2016.

3.47 System demand and inertia values have been calculated by the SOF team using a combination of actual demand and generation and predicted values in line with Future Energy Scenarios (FES) data.

3.48 SOF is predicting a decline in system inertia as demonstrated in the following figures 12 and 13.

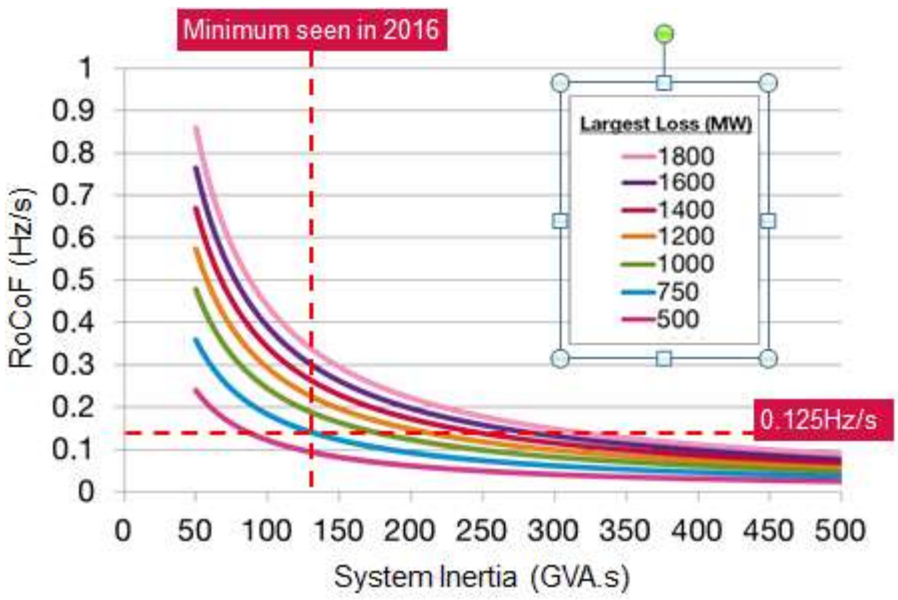


Figure 12

3.49 This plot shows the relationship between system inertia, RoCoF and the largest loss risk on the system.

3.50 As system inertia decreases or the largest loss increases, the RoCoF risk increases.

3.51 The minimum inertia witnessed so far in 2016 was about 135GVA.s, limiting the largest loss to 680MW. This minimum is not a true minimum since it includes control action already taken for voltage control.

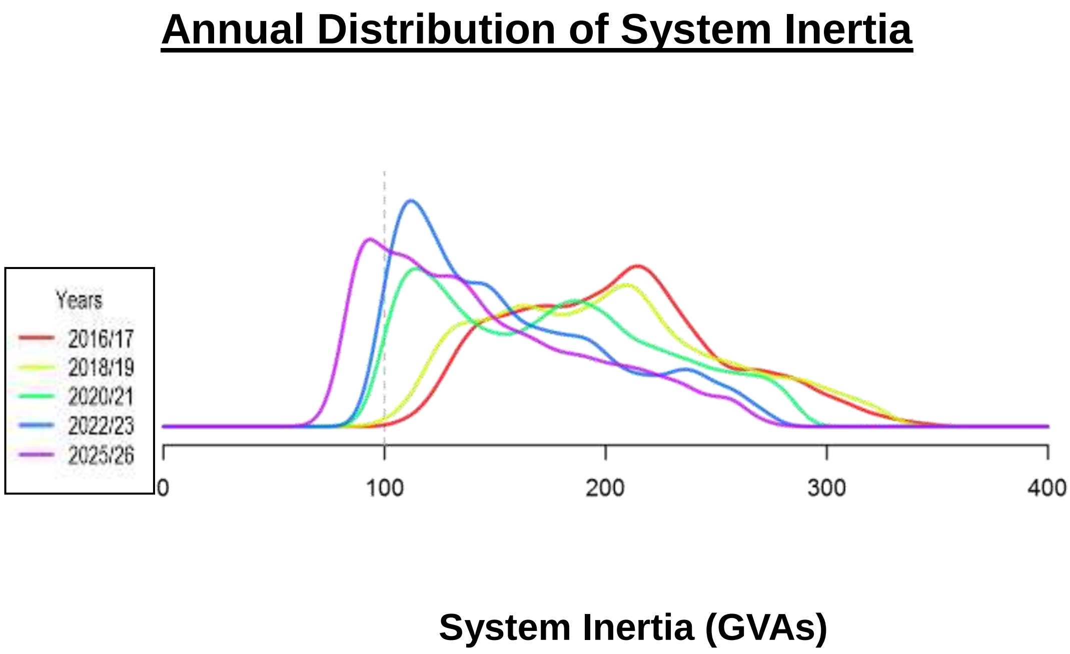


Figure 13

3.52 Figure 13 demonstrates the percentage of time that system inertia will be at a low value is increasing year on year. This data is taken from the Consumer Power Scenario defined in FES (Future Energy Scenarios).

3.53 The following table displays the values of RoCoF calculated at three minimum points in 2016, 2020 and 2025 taken from 2016 SOF data. The values were calculated using the standard RoCoF formula of:

3.54 $\text{RoCoF [Hz/s]} = \frac{50\text{ [Hz]}}{2} \times \frac{\text{Imbalance [MW]}}{\text{System inertia [MVA.s]}}$

Year	Min MVAs	1260(MW loss)	1500(MW loss)	1800(MW loss)
2016	103777	-0.30Hzs^{-1}	-0.36Hzs^{-1}	-0.43Hzs^{-1}
2020	86678	-0.36Hzs^{-1}	-0.43Hzs^{-1}	-0.52Hzs^{-1}
2025	69772	-0.45Hzs^{-1}	-0.54Hzs^{-1}	-0.64Hzs^{-1}

Table 9 – Projected RoCoF rates

3.55 The figures in the table illustrate that by 2020 RoCoF values of over 0.5 Hzs^{-1} are projected using 2016 FES data for a 1800MW loss and in 2025 for a 1500MW loss and above.

Value Hzs^{-1}

5.63 Therefore taking in to consideration the more onerous issue of islanding (where a generating plant could be isolated from the rest of the network and may have to deload rapidly) and the figures calculated, National Grid proposed a 1.0 Hzs^{-1} value measured over a 500ms period for RoCoF withstand capability for new plant connecting to the system. The workgroup agreed to this proposal at the meeting on 18th October 2016. A question has been raised as to whether this should be measured or averaged over 500ms. Evidence gathered following system incidents and subsequent transient analysis suggests that a more meaningful value for RoCoF withstand capability is achieved when RoCoF is averaged over 500ms rather than shorter measurement periods. When RoCoF is measured using short averaging periods, transient spikes of RoCoF are observed for a short period after a fault (in particular in close proximity to a fault) which could lead to misleading results.

5.64 Following a system imbalance incident, all plant connected to the system experiences the associated RoCoF effect. While it is recognised that RfG only applies to new plant connecting to the system after May 2018 and therefore the $1Hzs^{-1}$ RoCoF will be the capability of initially only a small percentage of plant. Due to the importance of robust RoCoF withstand capability in the short to medium term, and in order for it to become the standard of the future, we need to specify that capability from the date of approval of this modification. Further work is also required to establish the RoCoF withstand capability of plant currently on the system.

5.65 Island Operation

Note: RfG article 15.5(b) states that the TSO may require power generating modules to be capable of taking part in island operation, National Grid would expect this to be the case unless otherwise advised within a bilateral connection agreement.

4 Solution

Issue	Article	Requirement	Range		Suggested GB Value		Interactions	Policy reqd (eg non-compatiblity to be defined)?	Code Change reqd
	Type A								
1.	13.1(a)	Frequency Ranges	47 – 47.5Hz 47.5 – 48.5Hz 48.5 – 49.0Hz 49.0 – 51.0Hz 51.0 – 51.5Hz 51.5 – 52Hz	20 seconds 90 minutes TSO defined (not less than 90mins) Unlimited 90 minutes 15 minutes	47 – 47.5Hz 47.5 – 49.0Hz 49.0 – 51Hz 51.0 – 51.5Hz 51.5 – 52Hz	20 seconds 90 minutes Continuous 90 minutes 15 minutes	GC0091 DCC RfG voltage/reactive workstreams	N	N
2.	13.2	LFSM-O	Frequency threshold	50.2 – 50.5Hz	Frequency threshold	50.4Hz	HVDC/DCC		
			Droop	2 – 12%	Droop	10% (2%/0.1Hz)			
			Activation delay	<2 s	Activation delay	<2s		To define activation time in GC	
	13.2(a)	How is it						This has been	

		instructed?						answered in section 4	
	13.2(b)	Automatic disconnection					DCC/DCRP		
	13.2(f)	DMOL							Y
3.	13.3	Maintenance of Constant Active Power	49.5 – 50.5 Hz? – By interpretation		49.5 – 50.4Hz				Y
4.	13.4 &13.5	Power Output with Falling Frequency	Below 49Hz falling by a reduction rate of 2% of the Maximum Capacity at 50Hz per 1Hz Frequency drop Below 49.5Hz by a reduction rate of 10% of the maximum Capacity at 50Hz per 1Hz Frequency drop		Power Output should not drop by more than prorata with frequency (ie maximum permitted requirement is 100% power at 49.5Hz falling linearly to 95% at 47.0Hz)				Y
	Type C								
5.	15.2(c)	LFSM-U	Frequency Threshold Droop Initial Delay	49.8–49.5Hz 2 – 12% <2s	Frequency Threshold Droop Initial Delay	49.5Hz 10% <2s		Y	Y
6.	15.2(d)	FSM	Active Power range Frequency Insensitivity Frequency	1.5 – 10% 10 – 30mHz 0.02–0.06% 0-500mHz	Active Power range $|\Delta P_1|/P_{max}$ Frequency Insensitivity $|\Delta f_i|$ Frequency Insensitivity	10% ±15mHz ±0.03%		Y	Y

			Insensitivity Deadband Droop Maximum admissible initial delay t_1 for Generation with Inertia Maximum admissible initial delay t_1 for Generation without Inertia Full activation time t_2	 2 – 12% 2s TSO defined 30s	$\mathrm{I}\Delta f_i\mathrm{I}$ /f_n Deadband Droop Maximum admissible initial delay t_1 for Generation with Inertia Maximum initial admissible delay t_1 for Generation without Inertia Full activation time t_2	 0 3 – 5% 2s 1s 10s			
7.	15.2(g)	ASBMON	Status Signal (on/off) Scheduled Active Power output Actual value of Active Power output Actual parameter settings for Active Power Frequency Response Droop and deadband		Status Signal (on/off) Scheduled Active Power output Actual value of Active Power output Actual parameter settings for Active Power Frequency Response Droop and deadband			Y	Y
8.	13.1(b)	RoCoF withstand	To be defined by the TSO		+/-1Hzs^{-1}		DCC	Y	Y

5 Impacts and Other Considerations

Impact on the Grid Code

5.1 The work group suggests a set of modifications to the Grid Code Connection Conditions, and the Balancing Code.

Impact on Grid and Distribution Code Users

5.2 Users will have to comply with the revised Grid and Distribution Code requirements, but this will ensure compliance with EU and UK law.

5.3 This most significant impact on Grid Code Users will result from the specification of capabilities such as LFSM-U, FSM and RoCoF Withstand.

Impact on National Electricity Transmission System (NETS)

5.4 The inclusion of RoCoF withstand capability (and in a limited way LFSM-U) should enable NGET to better manage low system inertia periods.

Impact on Greenhouse Gas emissions

5.5 Clearly defined initial delay times for frequency response may result in a reduction of response requirements and therefore has the potential to reduce greenhouse gas emissions from response providing generators.

Assessment against Grid Code Objectives

5.6 To be confirmed

Impact on core industry documents

5.7 The GB Grid Code

Impact on other industry documents

5.8 Distribution Code, G59/83/98/99

Impact on Bilateral Agreements

5.9 None

Implementation

5.10 The Workgroup proposes that the proposed changes should link with other RfG changes and be implemented 10 business days after an Authority decision.

6 Relevant Objectives

Impact of the modification on the Relevant Objectives:	
Relevant Objective	**Identified impact**
To permit the development, maintenance and operation of an efficient, coordinated and economical system for the transmission of electricity	**Positive**
To facilitate competition in the generation and supply of electricity (and without limiting the foregoing, to facilitate the national electricity transmission system being made available to persons authorised to supply or generate electricity on terms which neither prevent nor restrict competition in the supply or generation of electricity)	**Positive**
Subject to sub-paragraphs (i) and (ii), to promote the security and efficiency of the electricity generation, transmission and distribution systems in the national electricity transmission system operator area taken as a whole	**Positive**
To efficiently discharge the obligations imposed upon the licensee by this license and to comply with the Electricity Regulation and any relevant legally binding decisions of the European Commission and/or the Agency; and	**Positive**
To promote efficiency in the implementation and administration of the Grid Code arrangements	**Positive**

6.1 GC0087 set out to implement the EU (RfG) with regard to Frequency Response. Specifically, Frequency Ranges, Frequency Response ((including LFSM-O (Limited Frequency Sensitive Mode-Overfrequency), LFSM-U (Limited Frequency Sensitive Mode Underfrequency) and FSM (Frequency Sensitive Mode(FSM)), Maintenance of Constant Active Power, Power Output with Falling Frequency, Monitoring and RoCoF (Rate of Change of Frequency) Withstand Capability.

6.2 It was agreed by the workgroup at the start of the process that the main objective was to try to align the (RfG) as closely as possible with what is currently specified in Grid Code, but also refining and improving current practice/definitions where possible. We believe that this has been achieved.

7 Implementation

7.1 This consultation proposes that the changes should link with other RfG changes and be implemented 10 business days after an Authority decision.

8 How to Respond to the Consultation

If you wish to respond to this Code Administrator Consultation, please use the response pro-forma which can be found under the 'Industry Consultation' tab via the following link;

http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/Modifications/GC0087/

Responses are invited to the following questions;

1. Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.

2. Do you believe that GC0087 better facilitates the Applicable Grid Code objectives? Please include your reasoning.

3. Do you have any other comments?

Views are invited on the proposals outlined in this consultation, which should be received by 11 May 2017. Please email your formal response to: Grid.Code@nationalgrid.com

If you wish to submit a confidential response, please note the following;

Information provided in response to this consultation will be published on National Grid's website unless the response is clearly marked 'Private & Confidential', we will contact you to establish the extent of this confidentiality. A response marked 'Private & Confidential' will be disclosed to the Authority in full by, unless agreed otherwise, will not be shared with the Grid Code Modifications Panel or the industry and may therefore not influence the debate to the same extent as a non-confidential response.

Please note an automatic confidentiality disclaimer generated by your IT System will not in itself, mean that your response is treated as if it had been marked 'Private & Confidential'

Annex 1 – Modification Proposal Form

Grid Code Review Panel

FREQUENCY RESPONSE PROVISIONS

Date Raised: 4 November 2014

GCRP Ref: pp14/59[1]

A Panel Paper by Graham Stein

National Grid

Summary
Proposals to develop the Frequency Response Provisions of the Grid Code under GC0022 did not reach a conclusion. National Grid believes that there are a number of outstanding defects with the Frequency Response provisions of the Grid Code which should be addressed in a new Workgroup under the issue reference GC0087.

Users Impacted
High All generators and interconnectors

Description & Background
The proposals packaged under GC0022 resulted from extended discussions under a joint Grid Code and Balancing Services Standing Group workgroup. The workgroup itself commissioned further work from a technical sub-group. The workgroup's proposals were presented in a Workgroup Consultation which closed on 30th October 2012. The proposals included the development of mandatory provisions for "5 second response from non-synchronous plant". Responses to the workgroup consultation were evenly divided in support and against developing these proposals. The consultation also included proposals for the development of clearer requirements with respect to the delivery of frequency response in terms of minimum delay and ramping parameters. A majority of the respondents were in favour of developing these. Subsequent discussions at the Balancing Services Standing Group confirmed that there is still no consensus over the benefit of "5 second response" as a mandatory requirement for new non-synchronous generation. In the meantime, National Grid has developed commercial terms for the provisions of a 5 second response service. A number of additional issues relating to Grid Code requirements were highlighted in the Frequency Response workgroup which remain outstanding. These included the suppression of the inertial effect of synchronous generators, the provisions of frequency

[1] The Code Administrator will provide the paper reference following submission to National Grid.

response by generators at low loads and the provisions of frequency response from on-site sources other than generators.

National Grid believes that it is necessary to form a Grid Code Workgroup to progress the outstanding issues related to Grid Code provisions to a conclusion. Given the expert input required and the general level of industry workload it is proposed that work should commence in April 2015. This will allow the Workgroup to consider the changes necessary to implement the Requirements for Generators provisions from frequency response.

	Issue	**Defect**	**Pros**	**Cons**
a	5 second response for non-synchronous generators	The current mandatory capability is not efficient in addressing future frequency requirements on its own	Reduced Balancing Services Costs	Increased costs for generators
b	Clearer delay and ramp-rate requirements	Current provisions leave some uncertainty over how generators should deliver frequency response	Clearer requirements	Risk of requirements being too onerous
c	Low load operation	Current provisions limit generator's ability to operate at low loads	Facilitates flexible operation from generators	Complex requirements
d	Alternative on-site sources	Current provisions limits the use of alternative solutions (eg on-site batteries)	Alternative ways of providing response	Potentially limited application

National Grid sees significant future benefits from faster forms of frequency response. Updated analysis of the year 2021/22 suggests that a 5 second response capability has value on 60% of summer overnight periods, with an average of 945MW of "rapid" response scheduled (with a peak value of 1624MW scheduled). The capability also had value on 24% of winter overnight periods.

Clearer delays and ramp-rate requirements would have benefits for National Grid in assessing system performance and would help developers to specify plant capability. There may be benefits in reviewing frequency response requirements for generators at low loads and also reviewing how alternative on-site sources may contribute to mandatory frequency response requirements.

In National Grid's view there is value in reviewing the four items listed above. There will also be a requirement to review Grid Code provisions for frequency response to implement the provisions of the European Commission's Requirement for Generators Code and to co-ordinate with the GCRP/DCRP Workgroup on GB Application of RfG (GC0048).

Feedback is sought from the Panel on the merits of developing conclusions for (a) to (d) above and whether there are any material related issues which could be dealt with in the same package. Subject to the Panel's feedback, detailed terms of reference will be presented in January 2015. It is anticipated that a Grid Code Workgroup would commence its work in or around April 2015.

Proposed Solution
Develop proposals to address issues (a) to (d) above in the context of RfG.

Assessment against Grid Code Objectives
The proposed changes to the Grid code will better facilitate Grid Code Objectives: ***(i) to permit the development, maintenance and operation of an efficient, coordinated and economical system for the transmission of electricity;*** Faster frequency response and flexible operation has the potential to reduce future Balancing Services costs. ***(ii) to facilitate competition in the generation and supply of electricity (and without limiting the foregoing, to facilitate the national electricity transmission system being made available to persons authorised to supply or generate electricity on terms which neither prevent nor restrict competition in the supply or generation of electricity);*** Facilitating the use of alternative on-site sources may allow generators to use alternative approaches to frequency response. ***(iii) subject to sub-paragraphs (i) and (ii), to promote the security and efficiency of the electricity generation, transmission and distribution systems in the national electricity transmission system operator area taken as a whole;*** and ***(iv) to efficiently discharge the obligations imposed upon the licensee by this license and to comply with the Electricity Regulation and any relevant legally binding decisions of the European Commission and/or the Agency.*** Grid Code provisions for frequency response need to be aligned with the Requirements for Generators European Code.

Impact & Assessment
Impact on the National Electricity Transmission System (NETS) No

Impact on Greenhouse Gas Emissions

Faster frequency response and flexible operation has the potential to reduce greenhouse gas emissions

Impact on core industry documents

The workgroup will consider any consequential impacts on the CUSC.

Impact on other industry documents

None

Supporting Documentation
None

Recommendation
The Grid Code Review Panel is invited to: Review the issues presented for consideration under the Grid Code Workgroup GC0087.

Annex 2 – Terms of Reference

GC0087 REQUIREMENTS FOR GENERATORS FREQUENCY PROVISIONS
TERMS OF REFERENCE

Governance

1. The Workgroup is responsible for the evaluation of Grid Code Modification Proposal GC0087 "Requirements for Generators Frequency Provisions" tabled by National Grid Electricity Transmission at the Grid Code Review Panel meeting on 20th May 2015 and revised at the Grid Code Review Panel meeting on 16th September 2015.

2. The group will report to the GCRP and the proposal must be evaluated to consider whether it best facilitates achievement of the applicable Grid Code objectives.

Scope of Work

3. Implementation of the EU code Requirements for Generators is being progressed by the GC0048 Workgroup, which has developed a work programme consisting of 7 different workstreams. The GC0087 Workgroup has been tasked with progressing the Frequency workstream from the GC0048 work programme.

4. The workgroup shall also consider the interaction of its parameter setting with GC0091 the Demand Connection Code (DCC) workgroup and GC0090 the HVDC workgroup. The workgroup will also provide regular updates to the GC0048 workgroup.

5. The GC0087 Workgroup must consider the Frequency elements of EU Code Requirements for Generators (GC0048) implementation to ensure there is no discrepancy between the Grid Code and the EU Code. The scope of the work shall include:

   - Frequency Ranges
   - Limited Frequency Sensitive Mode – Overfrequency (LFSM-O)
   - Maintenance of Constant Active Power
   - Power Output with Falling Frequency
   - Limited Frequency Sensitive Mode – Underfrequency (LFSM-U)
   - Frequency Sensitive Mode (FSM)
   - Ancillary Services Business Monitoring (ASBMON)
   - Compliance with frequency requirements
   - Setting of the all the parameters associated with all frequency modes
   - Generators' Rate of Change of Frequency (RoCoF) withstand capability

6. In its assessment of the proposals the workgroup will consider the costs, risks and benefits of each proposal incorporating the inherent characteristics of the relevant technologies.

7. The Workgroup will submit its final report to the Grid Code Review Panel meeting in September 2016 which will:

- Detail the findings of the Group
- Draft, prioritise and recommend changes to the Grid Code and associated documents in order to implement the findings of the Group, and
- Highlight any consequential changes which are or may be required

8. If for any reason the Workgroup is in existence for more than one year, the Workgroup will produce a yearly update report, including but not limited to; current progress, reasons for any delays, next steps and likely conclusion dates.

Membership

9. The Workgroup shall comprise a suitable and appropriate cross-section of experience and expertise from across the industry, which shall include:

Name	Role	Representing
Chairman	Graham Stein	National Grid
Technical Secretary	Franklin Rodrick	National Grid
National Grid Representative*	Fiona Williams	National Grid
Industry Representative*	Joe Duddy	RES Ltd
Industry Representative*	Alistair Frew	Scottish Power
Industry Representative*	Andrejs Svalovs	GE
Industry Representative*	Phil Jenner	Horizon Nuclear Power
Industry Representative*	Guy Nicholson	Element Power
Industry Representative*	Niall Duncan	Senvion
Industry Representative*	Clement Amerigo	EdF Energy
Industry Representative*	Ben Turner	ESB
Industry Representative*	Chris Marsland	Energ
Industry Representative*	Amir Daresobh	Nordex
Industry Representative*	Peter Woodcock	RWE
Industry Representative*		
Authority Representative	Stephen Perry	Ofgem
Observers		

NB: The Workgroup must comprise at least [5] members (who may be panel members). The roles identified with an asterisk in the table above contribute towards the required quorum, determined in accordance with paragraph 10 below.

10. The Chair of the Workgroup and the Grid Code Review Panel Chair must agree a number that will be quorum for each Workgroup meeting. The agreed figure for GC0087 is that at least 5 Workgroup members must participate in a meeting for the quorum to be met.

11. The frequency and dates of Workgroup meetings shall be defined by the Workgroup Chair and agreed in advance to meet the scope and objectives of the work being undertaken in a timely manner.

12. National Grid will provide technical secretary resource to the Workgroup and handle administrative arrangements such as venue, agenda and minutes.

13. The Workgroup will have a dedicated section on the National Grid website to enable information such as minutes, papers and presentations to be available to a wider audience.

Annex 3 – Attendance Register

Joe Duddy	RES	Workgroup member
Amir Dahresobh	Nordex	Workgroup member
Peter Woodcock	RWE	Workgroup member
Phil Jenner	Horizon Nuclear Power	Workgroup member
Alistair Frew	Scottish Power	Workgroup member
Andrejs Svalovs	General Electric	Workgroup member
Damian Jackman	SSE	Workgroup member
Andy Vaudin	EDF	Workgroup member
Clement Amerigo		Workgroup member
David Griffiths	RWE	Workgroup member
Paul Graham	UK Power Reserve	Workgroup member
Mick Barlow	S&C Electric	Workgroup member
Hayden Scott-Dye	Tidal Lagoon Power	Workgroup member
Niall Duncan	Senvion	Workgroup member
Razvan Pabat-Stroe	Scottish Power Energy Networks	Workgroup member
Sridhar Sahukari	DONG Energy	Workgroup member

DRAFT FREQUENCY LEGAL TEXT

Key

1) Blue Text – From Grid Code
2) Black Text – Changes / Additional words
3) Orange/ Brown text – From RfG
4) Highlighted Green text – Questions for Stakeholders / Consultation
5) Highlighted yellow text – Nomenclature / Table / Figure numbers – to be finalised when more detail has been added

GLOSSARY AND DEFINITIONS

A complete review of the Glossary and Definitions will be required when the full suite of European Codes has been implemented. The current assumption is to use GB definitions where appropriate with use of European definitions where required. The current European definitions used in the text are summarised below but it should be stressed that this is very much work in progress and further revisions will be required in the future.

Term	Definition
Genset	A **Power Generating Module** which is either **Type D**, ~~**Generating Unit**, **Power Park Module or CCGT Module** at a **Large Power Station** or any **Generating Unit**, **Power Park Module** or **CCGT Module**~~, directly connected to the **National Electricity Transmission System** or **a BM Participant**.
Registered Capacity	It is proposed that the GB definition of **Registered Capacity** is the same as the EU definition of "**Maximum Capacity**" (Pmax). There is some reference in the attached drafting which relates to **Registered Capacity** and **Maximum Capacity**. A possible option would be to change the definition of **Registered Capacity** in the GB Code the "**Registered Capacity or Pmax**"
Generator	It is suggested that the GB term **Generator** is used rather than the EU term of power generating facility owner.
Generating Unit	It is suggested that the term **Generating Unit** is used instead of the EU term of "**alternator**".
Frequency Insensitivity	Inherent feature of the control system specified as the minimum magnitude of change in the frequency or input signal that results in a change of output power or output signal
Frequency Response Deadband	An interval used intentionally to make the frequency control unresponsive In the case of mechanical governor systems the Governor Deadband is the same as Frequency Response Insensitivity
P_{ref}	P_{ref} for a **Synchronous Power Generating Module** is maximum capacity and for a **Power Park Module** it is based on the amount of

	plant in service
Maximum Capacity or P_{max}	The maximum continuous **Active Power** which a power generating module can produce, less any demand associated solely with facilitating the operation of that power generating module and not fed into the network as specified in the connection agreement or as agreed between the relevant system operator and the power generating facility owner;
Δf	Deviation from **Target Frequency**
CCGT Module	A collection of **Generating Units** (registered as a **CCGT Module** under the PC) comprising one or more **Gas Turbine Units** (or other gas based engine units) and one or more **Steam Units** where, in normal operation, the waste heat from the **Gas Turbines** is passed to the water/steam system of the associated **Steam Unit** or **Steam Units** and where the component units within the **CCGT Module** are directly connected by steam or hot gas lines which enable those units to contribute to the efficiency of the combined cycle operation of the **CCGT Module**.
Definitions of physical quantities such as voltage and frequency	In developing the Grid Code legal text, it has been assumed that we will retain GB definitions where possible and only use European definitions where there is a need to do so. The issue of physical quantities was raised on a number of occasions and that a pragmatic approach developed. The principle adopted is that physical quantities such as voltage and current are not defined in the GB Grid Code. It is proposed that this approach is retained so that when terms such as voltage and current are used in the GB code they are not defined, the intention being that the term current or voltage is then used in the appropriate context.

ECC.6.1.2 Grid Frequency Variations

ECC.6.1.2.1 The **Frequency** of the **National Electricity Transmission System** shall be nominally 50Hz and shall be controlled within the limits of 49.5 - 50.5Hz unless exceptional circumstances prevail.

ECC.6.1.2.2 The **System Frequency** could rise to 52Hz or fall to 47Hz in exceptional circumstances. Design of **User's Plant** and **Apparatus** and **OTSDUW Plant and Apparatus** must enable operation of that **Plant** and **Apparatus** within that range in accordance with the following:

Frequency Range	Requirement
51.5Hz - 52Hz	Operation for a period of at least 15 minutes is required each time the Frequency is above 51.5Hz.
51Hz - 51.5Hz	Operation for a period of at least 90 minutes is required each time the Frequency is above 51Hz.
49.0Hz - 51Hz	Continuous operation is required
47.5Hz - 49.0Hz	Operation for a period of at least 90 minutes is required each time the Frequency is below 49.0Hz.
47Hz - 47.5Hz	Operation for a period of at least 20 seconds is required each time the Frequency is below 47.5Hz.

ECC.6.1.2.3 For the avoidance of doubt, disconnection, by frequency or speed based relays is not permitted within the frequency range 47.5Hz to 51.5Hz. **Generators** should however be aware of combined voltage and frequency operating ranges as defined in ECC.6.3.12 and ECC.6.3.14X.

ECC.6.1.2.4 **NGET** in co-ordination with the **Relevant Transmission Licensee** and/or **Network Operator** and a **User** may agree on wider variations in frequency or longer minimum operating times to those set out in ECC.6.1.2.2. or specific requirements for combined frequency and voltage deviations. Any such requirements shall in accordance with ECC.6.3.12 and be pursuant to the terms of the **Connection Agreement**. The **User** shall not unreasonably withhold consent to apply wider frequency ranges or longer minimum times for operation taking account of their economic and technical feasibility.

ECC.6.3.1 GENERAL **POWER GENERATING MODULE** (AND **OTSDUW**) REQUIREMENTS

ECC.6.3.1.1 This section sets out the technical and design criteria and performance requirements for **Type A, Type B, Type C** and **Type D Power Generating Modules** ~~**DC Converters** and **Power Park Modules**~~ (whether directly connected to the **National Electricity Transmission System** or **Embedded**) and (where provided in this section) **OTSDUW Plant and Apparatus** which each **Generator** ~~or **DC Converter Station**~~ owner must ensure are complied with in relation to its AC connected **Power Generating Modules** ~~**Generating Units**, **DC Converters** and **Power Park Modules**~~ and **OTSDUW Plant and Apparatus** ~~but does not apply to **Small Power Stations** or individually to **Power Park Units**~~. References to **Type A**, **Type B**, **Type C** and **Type D Power Generating Modules** ~~**Units**, **DC Converters** and **Power Park Modules**~~ in this ECC.6.3 should be read accordingly. For the avoidance of doubt, **Type A** and **Type B Power Generating Modules** owned by **Generators** not subject to a **Bilateral Agreement** and without a **CUSC Contract**, would have to satisfy the requirements specified in the **Distribution Code**.

ECC.6.3.1.2 For the avoidance of doubt the requirements for **HVDC Systems**, **DC Connected Power Park Modules**, **DC Converters**, **DC Converter Stations** and **OTSDUW DC Converters** are contained are defined in ECC.6.X.X.X

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ECC.6.3.3 OUTPUT POWER WITH FALLING FREQUENCY

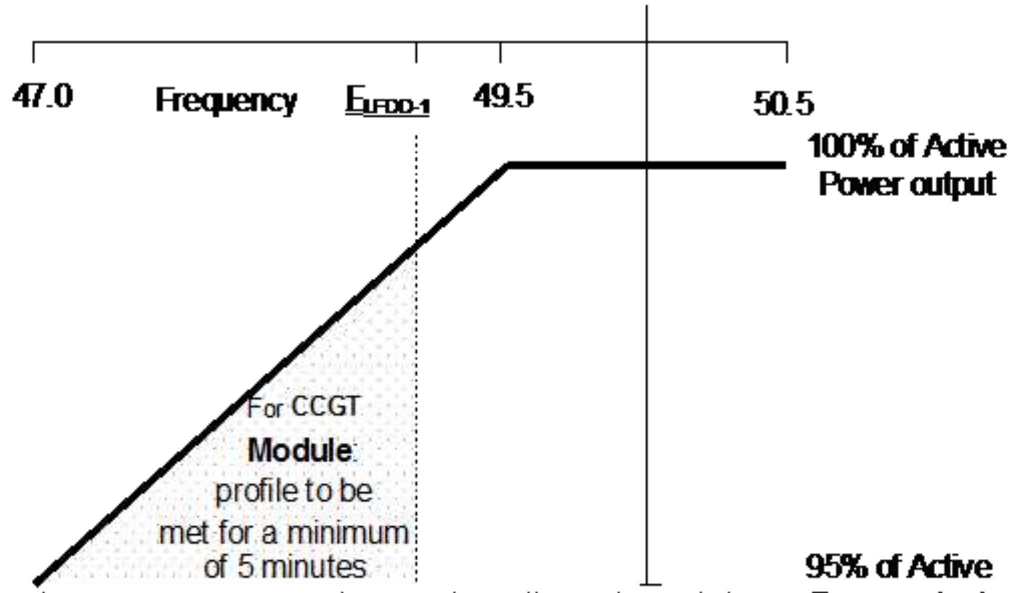
ECC.6.3.3.1 Output power with falling frequency for **Type A, Type B, Type C** and **Type D Power Generating Modules**

CC.6.3.3.1.1 Each **Type A, Type B, Type C** and **Type D Power Generating Module**, must be capable of:

(a) continuously maintaining constant **Active Power** output for **System Frequency** changes within the range 50.5 to 49.5 Hz; and

(b) (subject to the provisions of ECC.6.1.2) maintaining its **Active Power** output at a level not lower than the figure determined by the linear relationship shown in Figure X2 for **System Frequency** changes within the range 49.5 to 47 Hz for all ambient temperatures up to and including 25^{o}C, such that if the **System Frequency** drops to 47 Hz the **Active Power** output does not decrease by more than 5%. In the case of a **CCGT Module**, the above requirement shall be retained down to the **Low Frequency Relay** trip setting of 48.8 Hz, which reflects the first stage of the Automatic Low **Frequency Demand Disconnection** scheme notified to **Network Operators** under EOC6.6.2. For **System Frequency** below that setting, the existing requirement shall be retained for a minimum period of 5 minutes while **System Frequency** remains below that setting, and special measure(s) that may be required to meet this requirement shall be kept in service during this period. After that 5 minutes period, if **System Frequency** remains below that setting, the special measure(s) must be discontinued if there is a materially increased risk of the **Gas Turbine** tripping. The need for special measure(s) is linked to the inherent **Gas Turbine Active Power** output reduction caused by reduced shaft speed due to falling **System Frequency**. Where the need for special measures is identified in order to maintain output in line with the level identified in Figure X2 these measures should be still continued at ambient temperatures above 25^{o}C maintaining as much of the Active Power achievable within the capability of the plant.

Figure X2



Note: Frequency F_{LFDD-1} is the relay trip setting of the first stage of the Automatic Low Frequency Demand Disconnection Scheme

(c) For the avoidance of doubt in the case of a **Power Generating Module** ~~**Generating Unit** or **Power Park Module** (or **OTSDUW DC Converters** at the **Interface Point**)~~ using an **Intermittent Power Source** where the mechanical power input will not be constant over time, the requirement is that the **Active Power** output shall be independent of **System Frequency** under (a) above and should not drop with **System Frequency** by greater than the amount specified in (b) above.

~~(d) A **DC Converter Station** must be capable of maintaining its **Active Power** input (i.e. when operating in a mode analogous to **Demand**) from the **National Electricity Transmission System** (or **User System** in the case of an **Embedded DC Converter Station**) at a level not greater than the figure determined by the linear relationship shown in Figure 3 for **System Frequency** changes within the range 49.5 to 47 Hz, such that if the **System Frequency** drops to 47.8 Hz the **Active Power** input decreases by more than 60%.~~

(d) , In the case of an **Offshore Generating Unit** or **Offshore Power Park Module**~~, **Offshore DC Converter** and **OTSDUW DC Converter**~~, the **Generator** shall comply with the requirements of ECC.6.3.3. **Generators** should be aware that Section K of the **STC** places requirements on **Offshore Transmission Licensees** which utilise a **Transmission DC Converter** as part of their **Offshore Transmission System** to make appropriate provisions to enable **Generators** to fulfil their obligations.

~~(f) In the case of an **OTSDUW DC Converter** the **OTSDUW Plant and Apparatus** shall provide a continuous signal indicating the real time frequency measured at the **Interface Point** to the **Offshore Grid Entry Point**.~~

ECC.6.3.X **ACTIVE POWER** CONTROL

ECC.6.3.X.1 **Type A Power Generating Modules** shall be equipped with a logic interface (input port) in order to cease **Active Power** output within five seconds following an instruction being received at the input port. **NGET** or the **Network Operator** will specify the additional requirements for such a scheme including if the facility is to be operated remotely in the **Connection Agreement**.

ECC.6.3.X.2 **Type B Power Generating Modules** shall be equipped with an interface (input port) in order to be able to reduce **Active Power** output following an instruction at the input port. **NGET** or the **Network Operator** will specify any additional requirements (including remote operation) in the **Connection Agreement**.

ECC.6.3.X.3 **Type C** and **Type D Power Generating Modules** shall be capable of adjusting the **Active Power** setpoint in accordance with instructions issued by **NGET**, a **Relevant Transmission Licensee** or a **Network Operator. The timing of response to such instructions is specified in the Balancing Code.**

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ECC.6.3.5 BLACK START

ECC.6.3.5.1 It is an essential requirement that the **National Electricity Transmission System** must incorporate a **Black Start Capability**. This will be achieved by agreeing a **Black Start Capability** at a number of strategically located **Power Stations**. For each **Power Station NGET** will state in the **Bilateral Agreement** whether or not a **Black Start Capability** is required.

ECC.6.3.5.2 **Black Start** is not a mandatory requirement, however **Users** may wish to notify **NGET** of their ability to provide a **Black Start** facility and the cost of the service. **NGET** will then consider whether it wishes to contract with the **User** for the provision of a **Black Start** service which would be specified via a **Black Start** contract. Where a **User** does not offer to provide a cost for the provision of a **Black Start Capability**, **NGET** may make such a request if it considers **System** security to be at risk due to a lack of **Black Start** capability.

ECC.6.3.5.3 Where a **Black Start** Contract has been agreed between a **User** and **NGET**, the following requirements shall also apply to all **Type C** and **Type D Power Generating Modules**.

(i) A **Power-Generating Module** with a **Black Start Capability** shall be capable of starting from shutdown without any external electrical energy supply within a time frame specified by **NGET** in the **Black Start** contract.

(ii) In addition to the requirements of ECC.6.3.5.3(i) each **Power Generating Module** with a **Black Start Capability** shall also be able to synchronise within the frequency limits defined in ECC.6.1.3 ~~laid down in point (a) of Article 13(1)~~ and, where applicable, voltage limits specified ~~by the relevant system operator or in Article 16(2)~~ in ECC.6.1.4; For the avoidance of doubt a **Power Generating Module with a Black Start Capability** shall also be capable of connecting on to a dead **System**.

(iii) A **Power-Generating Module** with **Black Start Capability** shall be capable of automatically regulating dips in voltage caused by connection of demand;

(iv) A **Power Generating Module** with **Black Start Capability** shall:

be capable of regulating load connections in block load,

be capable of operating in **LFSM-O** and **LFSM-U**, as specified in ~~point (c) of paragraph 2 and Article 13(2)~~, XXXX.*(subnote – include ECC refs to LFSM-O and LFSM-U).*

control **Frequency** in case of overfrequency and underfrequency within the whole **Active Power** output range between Minimum Regulating Level and Maximum Capacity as well as at houseload level, be capable of parallel operation of a few **Power Generating Modules** within one island, and control voltage automatically during the system restoration phase;

ECC.6.3.5.4 With regard to the capability to take part in island operation:

(i) **Power Generating Modules** shall be capable of taking part in island operation if specified in the **Black Start Contract** required by the relevant system operator in coordination with the relevant TSO and:

the **Frequency** limits for island operation shall be those specified in ECC.6.1.2 ~~established in accordance with point (a) of Article 13(1)~~,

the voltage limits for island operation shall be those defined in ECC.6.1.4 *(Need to ensure consistency with Art 15(3)* ~~established in accordance with Article 15(3) or Article 16(2), where applicable~~;

~~(ii)~~ **Power Generating Modules** shall be able to operate in **Frequency Sensitive Mode** during island operation, as specified in ECC.6.3.7.X~~point (d) of paragraph 2~~. In the event of a power surplus, **Power Generating Modules** shall be capable of reducing the **Active Power** output from a previous operating point to any new operating point within the **Generator Performance Chart** ~~P-Q Capability Diagram. In that regard, the~~ **Power Generating Modules** shall be capable of reducing **Active Power** output as much as inherently technically feasible, but to at least 55 % of ~~its~~ Maximum Capacity~~;~~

In the case of **Black Start** all of the above applies. For all other **Power Generating Modules** see ECC.6.3.7.2.2(vii)

The method for detecting a change from interconnected system operation to island operation shall be agreed between the **Generator** ~~power generating facility owner~~ **NGET** and the **Relevant Transmission Licensee**. ~~the relevant system operator in coordination with the relevant TSO~~. The agreed method of detection must not rely solely on **NGET, Relevant Transmission Licensee's** or **Network Operators** ~~system operator's~~ switchgear position signals;

(iv) **Power Generating Modules** shall be able to operate in **LFSM-O** and **LFSM-U** during island operation, as specified in ECC.6.3.7.X ~~point (c) of paragraph 2~~ and ECC.6.3.X.X.~~Article 13(2)~~;

ECC.6.3.5.5 With regard to quick re-synchronisation capability:

(iii) In case of disconnection of the **Power Generating Module** from the **Network**, the **Power Generating Module** shall be capable of quick re-synchronisation in line with the **Protection** strategy agreed between **NGET** and/or **Network Operator** in co-ordination with the **Relevant Transmission Licensee**.~~the relevant system operator in coordination with the relevant TSO~~ and the **Generator** ~~power-generating facility;~~

(iv) A **Power Generating Module** with a minimum re-synchronisation time greater than 15 minutes after its disconnection from any external power supply must be designed to trip to houseload from any operating point on ~~in~~ its ~~**P-Q Capability Diagram**~~ **Generator Performance Chart**. In this case, the identification of **Houseload Operation** must not be based solely on ~~the~~ **NGET's**, **Relevant Transmission Licensee's** or **Network Operators** ~~system operator's~~ switchgear position signals;

(v) **Power Generating Modules** shall be capable of continuing operation following tripping to houseload, irrespective of any auxiliary connection to the **System** ~~external network~~. The minimum operation time shall be specified by **NGET** and/or **Network Operator** in co-ordination with the **Relevant Transmission Licensee** (where applicable) ~~athe relevant system operator in coordination with the relevant TSO~~, taking into consideration the specific characteristics of prime mover technology.

ECC.6.3.6 MODULATION OF ACTIVE AND REACTIVE POWER

ECC.6.3.6.1 Each **Power Generating Module** must be capable of contributing to **Frequency** control by continuous modulation of **Active Power** supplied to the **National Electricity Transmission System** or the **User System** in which it is **Embedded**. For the avoidance of doubt each **OTSDUW DC Converter** shall provide each **User** in respect of its **Offshore Power Stations** connected to and/or using an **Offshore Transmission System** a continuous signal indicating the real time **Frequency** measured at the **Transmission Interface Point**. *(This section of text will also be duplicated in the voltage/reactive text).*

ECC.6.3.6.2 Each **Power Generating Module** (and **OTSDUW Plant and Apparatus** at a **Transmission Interface Point**) must be capable of contributing to voltage control by continuous changes to the **Reactive Power** supplied to the **National Electricity Transmission System** or the **User System** in which it is **Embedded**.

ECC.6.3.7 FREQUENCY RESPONSE

ECC.6.3.7.1 **Limited Frequency Sensitive Mode – Overfrequency (LFSM-O)**

ECC.6.3.7.1.1 Each **Type A**, **Type B**, **Type C** and **Type D Power Generating Module** shall be capable of reducing **Active Power** output in response to **System Frequency** when this rises above 50.4Hz. For the avoidance of doubt, the provision of this reduction in **Active Power** output is not an **Ancillary Service**. Such provision is known as **Limited High Frequency Response**. The **Power Generating Module** shall be capable of operating stably during **LFSM-O** operation. However for a **Power Generating Module** in FSM the requirements of LFSM-O shall apply when frequency exceeds 50.5Hz.

ECC.6.3.7.1.2 (i) 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 (ie a Droop of 10%) as shown in Figure X1 below.

(ii) The reduction in **Active Power** output must be continuously and linearly proportional, as far as is practicable, to the excess of **Frequency** above 50.4 Hz and must be provided increasingly with time over the period specified in (iii) below.

(iii) As much as possible of the proportional reduction in **Active Power** output must result from the frequency control device (or speed governor) action and must be achieved within 10 seconds of the time of the **Frequency** increase above 50.4 Hz. The **Power Generating Module** shall be capable of initiating a power **Frequency** response with minimal delay. If the delay exceeds 2 seconds the **Generator** shall justify the delay, providing technical evidence to **NGET**, the **Network Operator** or **Relevant Transmission Licensee**. *(Multiple TSO clause issue)*

(vi) The residue of the proportional reduction in **Active Power** output which results from automatic action of the **Power Generating Module** output control devices other than the frequency control devices (or speed governors) must be achieved within 3 minutes for the time of the **Frequency** increase above 50.4Hz.

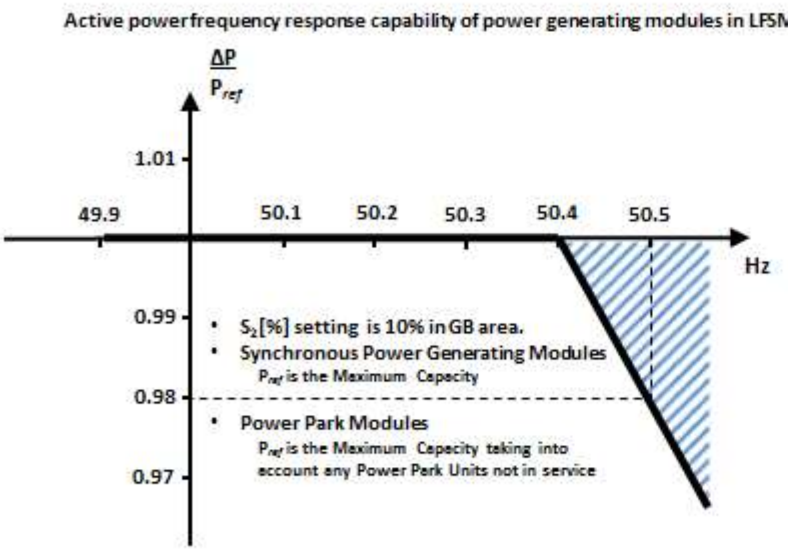

Figure X1 – P_{ref} is the reference **Active Power** to which ΔP is related and may be specified differently for **Synchronous Power Generating Modules** and **Power Park Modules**. ΔP is the change in **Active Power** output from the **Power Generating Module**. Fn is the nominal frequency (50Hz) in the network and Δf is the **Frequency** deviation in the network. At overfrequencies where Δf is below Δf_1 the **Power Generating Module** has to provide a negative **Active Power** output change according to droop S_2 which shall be no greater than 10%.

ECC.6.3.7.1.3 Each **Power Generating Module** which is providing **Limited High Frequency Response (LFSM-O)** must continue to provide it until the **Frequency** has returned to or below 50.4Hz or until otherwise instructed by **NGET** or the **Network Operator**. **Generators** in respect of **Type D Power Generating Modules** should also be aware of the requirements in BC.3.7.2.

ECC.6.3.7.1.4 Any further residue of the proportional reduction which results from non-automatic action initiated by the **Generator** shall be initiated within 2 minutes, and achieved within 5 minutes, of the time of the **Frequency** increase above 50.4 Hz

ECC.6.3.7.1.5 Steady state operation below **Minimum Generation** is not expected but if **System** operating conditions cause operation below **Minimum Generation** which give rise to operational difficulties for the **Power Generating Module** then the **Generator** shall be able to return the output of the **Power Generating Module** to an output of not less than the **Minimum Generation**.

ECC.6.3.7.1.6 All reasonable efforts should in the event be made by the **Generator** to avoid such tripping provided that the **System Frequency** is below 52Hz. If the **System Frequency** is at or above 52Hz, the requirement to make all reasonable efforts to avoid tripping does not apply and the **Generator** is required to take action to protect its **Power Generating Modules** as specified in ECC.6.3.13.

ECC.6.3.7.1.7 **Generators** responsible for **Type A**, **Type B**, **Type C** or **Type D Power Generating Modules** which are also **BM Participants** should also be aware of the requirements in BC.3.

ECC.6.3.7.2 **Limited Frequency Sensitive Mode – Underfrequency (LFSM-U)**

ECC.6.3.7.2.1 Each **Type C** and **Type D Power Generating Module** shall be capable of increasing **Active Power** output in response to **System Frequency** when this falls below 49.5Hz. For the avoidance of doubt, the provision of this increase in **Active Power** output is not an **Ancillary Service** and it is not anticipated **Power Generating Modules** are operated in an inefficient mode to facilitate delivery of **LFSM-U** response, but any inherent capability should be made available without undue delay. The **Power Generating Module** shall be capable of stable operation during **LFSM-U Mode**.

ECC.6.3.7.2.2 (i) 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 (ie a Droop of 10%) as shown in Figure X2 below. This requirement only applies if plant has headroom and the appropriate conditions are satisfied.

(ii) 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 **Power Generating Module** shall be capable of initiating a power Frequency response with minimal delay. If the delay exceeds 2 seconds the **Generator** shall justify the delay, providing technical evidence to **NGET**, the **Network Operator** or **Relevant Transmission Licensee** *(multiple TSO clause)*.

(iii) The actual delivery of **Active Power Frequency Response** in **LFSM-U** mode shall take into account

The ambient conditions when the response is to be triggered

The operating conditions of the **Power Generating Module**. In particular limitations on operation near **Registered** ~~**Maximum**~~ **Capacity** at low frequencies and the respective impact of ambient conditions as detailed in ECC.6.3.3.

The availability of primary energy sources.

(iv) In **LFSM_U Mode** the **Power Generating Module** shall be capable of providing a power increase up to its **Registered** ~~**Maximum**~~ **Capacity**.

Active power frequency response capability of power generating modules in LFSM-U

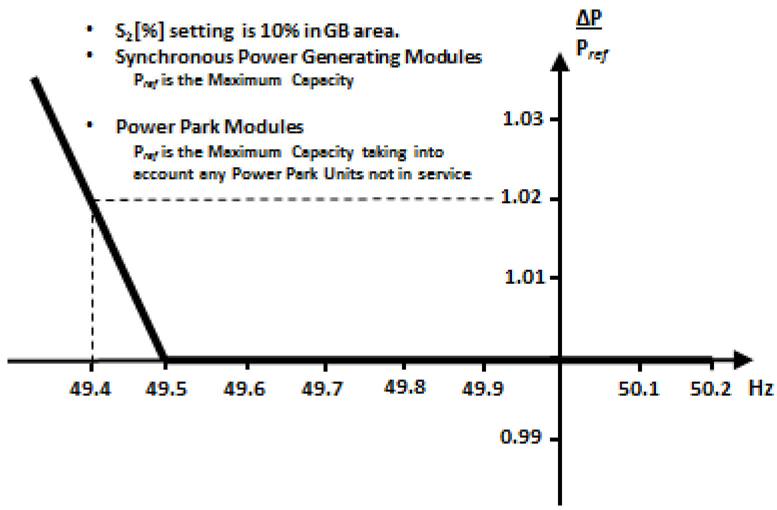

Figure X2 – Pref is the reference **Active Power** to which ΔP is related and may be specified differently for **Synchronous Power Generating Modules** and **Power Park Modules**. ΔP is the change in **Active Power** output from the **Power Generating Module**. Fn is the nominal frequency (50Hz) in the network and Δf is the frequency deviation in the network. At underfrequencies where Δf is below Δf_1 the **Power Generating Module** has to provide a positive **Active Power** output change according to droop S_2 which shall be no greater than 10%.

ECC.6.3.7.3 **Frequency Sensitive Mode – (FSM)**

ECC.6.3.7.3.1 In addition to the requirements of ECC.6.3.7.1 and ECC.6.3.7.2 each **Type C** and **Type D Power Generating Module** must be fitted with a fast acting proportional **Frequency** control device (or turbine speed governor) and unit load controller or equivalent control device to provide **Frequency** response under normal operational conditions in accordance with **Balancing Code 3** (**BC3**). In the case of a **Power Park Module** the **Frequency** or speed control device(s) may be on the **Power Park Module** or on each individual **Power Park Unit** or be a combination of both. The **Frequency** control device(s) (or speed governor(s)) must be designed and operated to the appropriate:

(i) **European Specification**: or

(ii) in the absence of a relevant **European Specification**, such other standard which is in common use within the European Community (which may include a manufacturer specification);

as at the time when the installation of which it forms part was designed or (in the case of modification or alteration to the **Frequency** control device (or turbine speed governor)) when the modification or alteration was designed.

The **European Specification** or other standard utilised in accordance with sub paragraph ECC.6.3.7.3.1 (a) (ii) will be notified to **NGET** or the **Network Operator** by the **Generator**:

(i) as part of the application for a **Bilateral Agreement**; or

(ii) as part of the application for a varied **Bilateral Agreement**; or

(iii) in the case of an **Embedded Development**, within 28 days of entry into the **Embedded Development Agreement** (or such later time as agreed with **NGET**); or *(LEEMPS Clause)*

(iv) as soon as possible prior to any modification or alteration to the **Frequency** control device (or governor); and

ECC.6.3.7.3.2 The **Frequency** control device (or speed governor) in co-ordination with other control devices must control each **Type C** and **Type D Power Generating Module Active Power Output** with stability over the entire operating range of the **Power Generating Module**; and

ECC.6.3.7.3.3 **Type C** and **Type D Power Generating Modules** shall also meet the following minimum requirements:

(i) **Power Generating Modules** shall be capable of providing **Active Power Frequency** response in accordance with the performance characteristic shown in Figure X3 and parameters in Table X1.

Active power frequency response capability of power generating modules in FSM

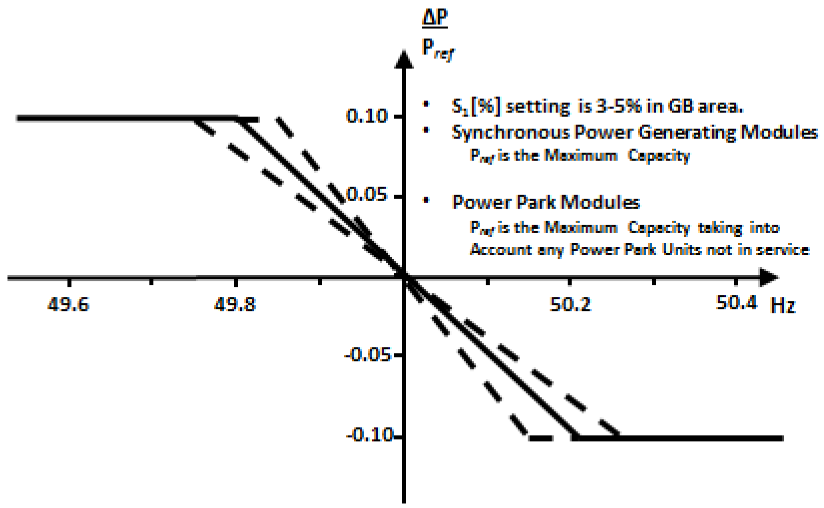

Figure X3 – P_{ref} is the reference **Active Power** to which ΔP is related. ΔP is the change in **Active Power** output from the **Power Generating Module**. F_n is the nominal **Frequency** (50Hz) in the **System** and Δf is the frequency deviation in the **System**. Figure X3 illustrates the case of zero **Deadband** and **Insensitivity**

Parameter	Setting
Nominal **System Frequency**	50Hz
Active Power as a percentage of **Maximum Capacity** ($\frac{\lvert\Delta P_1\rvert}{P_{max}}$)	10%
Frequency Response Insensitivity in mHz ($\lvert\Delta f_i\rvert$)	±15mHz
Frequency Response Insensitivity as a	±0.03%

percentage of nominal frequency ($\frac{\lvert\Delta f_i\rvert}{f_n}$)	
Frequency Response Deadband in mHz	0 (mHz)
Droop s_1 (%)	3 – 5%

Table X1 – Parameters for **Active Power Frequency** response in **FSM** including the mathematical expressions in Figure X3.

(ii) In satisfying the performance requirements specified in ECC.6.3.7.3(i) **Generators** in respect of each **Type C** and **Type D Power Generating Module** should be aware:-

in the case of overfrequency, the **Active Power Frequency** response is limited by the **Minimum Regulating Level**,

in the case of underfrequency, the **Active Power Frequency** response is limited by the **Registered** ~~**Maximum**~~ **Capacity,**

the actual delivery of **Active Power** frequency response depends on the operating and ambient conditions of the **Power Generating Module** when this response is triggered, in particular limitations on operation near **Maximum Capacity** at low **Frequencies** as specified in ECC.6.3.3 and available primary energy sources.

The frequency control device (or speed governor) must also be capable of being set so that it operates with an overall speed **Droop** of between 3 – 5%. The deadband and droop must be able to be reselected repeatedly. For the avoidance of doubt, in the case of a **Power Park Module** the speed **Droop** should be equivalent of a fixed setting between 3% and 5% applied to each **Power Park Unit** in service.

(iii) In the event of a **Frequency** step change, each **Type C** and **Type D Power Generating Module** shall be capable of activating full and stable **Active Power Frequency** response (without undue power oscillations), in accordance with the performance characteristic shown in Figure X4 and parameters in Table X2. ~~at (which shall aim at avoiding active power oscillations for the power generating module) within the ranges given in Table 5. The combination of choice of the parameters specified by the TSO shall take possible technology-dependent limitations into account;~~

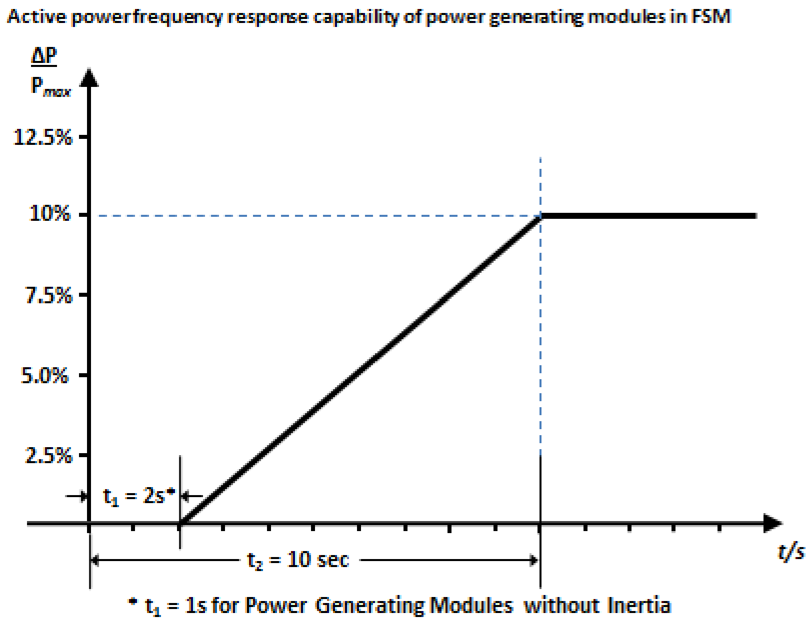

Figure X4 **Active Power Frequency Response** capability. P_{max} is the **Maximum Capacity** to which ΔP relates. ΔP is the change in **Active Power** output from the **Power Generating Module**. The **Power Generating Module** has to provide **Active Power** output ΔP up to the point ΔP_1 in accordance with the times t_1 and t_2 with the values of ΔP_1, t_1 and t_2 being specified in Table X2. t_1 is the initial delay. t_2 is the time for full activation.

Parameter	Setting
Active Power as a percentage of **Maximum Capacity (frequency response range)** ($\frac{\lvert\Delta P_1\rvert}{P_{max}}$)	10%
Maximum admissible initial delay t_1 for **Power Generating Modules** with inertia unless justified as specified in ECC.6.3.7.3.3 (iv)	2 seconds
Maximum admissible initial delay t1 for **Power Generating Modules** without inertia unless justified as specified in ECC.6.3.7.3.3 (iv)	1 second
Activation time t2	10 seconds

Table X2 – Parameters for full activation of **Active Power Frequency** response resulting from a **Frequency** step change. Table X2 also includes the mathematical expressions used in Figure X4.

(iv) The initial activation of **Active Power Primary Frequency** response ~~required~~ shall not be unduly delayed. For **Type C** and **Type D Power Generating Modules** with inertia the delay in initial **Active Power Frequency** response shall not be greater than 2 seconds. For **Type C** and **Type D Power Generating Modules** without inertia the delay in initial **Active Power Frequency** response shall not be greater than 1 second. If the **Generator** cannot meet this requirement they shall provide technical evidence to **NGET** demonstrating why a longer time is needed for the initial activation of **Active Power Frequency** response.

(v) in the case of **Type C** and **Type D Power Generating Modules** other than the **Steam Unit** within a **CCGT Module** the combined effect of the **Frequency Response Insensitivity** and **Frequency Response Deadband** of the **Frequency** control device (or speed governor) should be no greater than 0.03Hz (for the avoidance of doubt, ±0.015Hz). In the case of the **Steam Unit** within a **CCGT Module**, the **Frequency Response Deadband** should be set to an appropriate value consistent with the requirements of ECC.6.3.7(c)(i) and the requirements of BC3.7.2 for the provision of **LFSM-O** taking account of any **Frequency Response Insensitivity** of the Frequency control device (or speed governor);

~~(vi) the power-generating module shall be capable of providing full active power frequency response for a period of between 15 and 30 minutes as specified by the relevant TSO. In specifying the period, the TSO shall have regard to active power headroom and primary energy source of the power-generating module;~~

~~(vii) (vi) within the time limits laid down in point (v) of paragraph 2(d), active power control must not have any adverse impact on the active power frequency response of power-generating modules;~~ *(Not required as we define Primary and Secondary and High Frequency Response in GB).*

~~the parameters specified by the relevant TSO in accordance with points (i), (ii), (iii) and (v) shall be notified to the relevant regulatory authority. The modalities of that notification shall be specified in accordance with the applicable national regulatory framework;~~ *(Not required as it should be covered as part of the GB Governance process).*

~~(viii) with regard to frequency restoration control, the power-generating module shall provide functionalities complying with specifications specified by the relevant TSO, aiming at restoring frequency to its nominal value or maintaining power exchange flows between control areas at their scheduled values;~~ *(Not required as it covers AGC).*

(vi) with regard to disconnection due to underfrequency, **Generators** responsible for **Type C** and **Type D Power Generating Modules** capable of acting as a load, including but not limited to **Pumped Storage** and tidal **Power Generating Modules** ~~hydro pump-storage power-generating facilities~~, shall be capable of disconnecting their load in case of underfrequency which will be pursuant to the terms of the **Bilateral Agreement**. For the avoidance of doubt this requirement does not apply to station auxiliary supplies; Generators in respect of **Type C** and **Type D Pumped Storage Power Generating Modules** should also be aware of the requirements in OCC.6.6.6.

(vii) Where a **Type C** or **Type D Power Generating Module** becomes isolated from the rest of the **Total System** but is still supplying **Customers**, the **Frequency** control device (or speed Governor) must also be able to control **System Frequency** below 52Hz unless this causes the **Type C** or **Type D Power Generating Module** to operate below its **Designed Minimum Operating Level** when it is possible that it may, as detailed in BC 3.7.3, trip after a time. For the avoidance of doubt the **Power Generating Module** is only required to operate within the **System Frequency** range 47 - 52 Hz as defined in ECC.6.1.3 and for converter based technologies, the remaining island contains sufficient fault level for effective commutation;

(viii) Each **Type C** and **Type D Power Generating Module** shall have the facility to modify the **Target Frequency** setting either continuously or in a maximum of 0.05Hz steps over at least the range 50 ±0.1Hz should be provided in the unit load controller or equivalent device. Such requirements are necessary to fulfil the requirements of the **Balancing Codes**.

ECC.6.3.7.3.4 In addition to the requirements of ECC.6.3.7.3 each **Type C** and **Type D Power Generating Module** shall be capable of meeting the minimum **Frequency** response requirement profile subject to and in accordance with the provisions of Appendix 3.

ECC.6.3.7.3.5 For the avoidance of doubt, the requirements of Appendix 3 do not apply to **Type A** and **Type B Power Generating Modules**.

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ECC.6.3.9 STEADY STATE LOAD INACCURACIES

ECC.6.3.9.1 The standard deviation of **Load** error at steady state **Load** over a 30 minute period must not exceed 2.5 per cent of a **Type C** or **Type D Power Generating Modules** ~~Genset~~ **MaximumCapacity**. Where a **Type C** or **Type D Power Generating Module** ~~Genset~~ is instructed to **Frequency** sensitive operation, allowance will be made in determining whether there has been an error according to the governor droop characteristic registered under the **PC**.

For the avoidance of doubt in the case of a **Power Park Module** allowance will be made for the full variation of mechanical power output.

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ECC.6.3.12 FREQUENCY AND VOLTAGE DEVIATIONS

ECC.6.3.12.1 As stated in ECC.6.1.3, the **System Frequency** could rise to 52Hz or fall to 47Hz. Each **Power Generating Module** ~~**Generating Unit**, **DC Converter**, **OTSDUW Plant and Apparatus**, **Power Park Module** or any constituent element~~ must continue to operate within this **Frequency** range for at least the periods of time given in ECC.6.1.3 unless **NGET** and/or the **Network Operator** in coordination with the **Relevant Transmission Licensee** has agreed in the **Connection Agreement** to any specific requirements for combined **Frequency** and voltage deviations which are required to ensure the best use of technical capabilities of a **Power Generating Module** if it is required to preserve or restore system security. ~~**Frequency** level relays and/or rate-of-change-of **Frequency** relays which will trip such **Power Generating Module** **Generating Unit**, **DC Converter**, **OTSDUW Plant and Apparatus**, **Power Park Module** and any constituent element within this **Frequency** range, under the **Bilateral Agreement**.~~ Notwithstanding this requirement, **Generators** should also be aware of the requirements of ECC.6.3.14X.

ECC.6.3.13 GENERATOR FREQUENCY PROTECTION SETTING ARRANGEMENTS

ECC.6.3.13.1 **Generators** (including in respect of **OTSDUW Plant and Apparatus**)~~ and **DC Converter Station** owners~~ will be responsible for protecting all their **Power Generating Modules** ~~**Generating Units**~~ (and **OTSDUW Plant and Apparatus**)~~, **DC Converters** or **Power Park Modules**~~ against damage should **Frequency** excursions outside the range 52Hz to 47Hz ever occur. Should such excursions occur, it is up to the **Generator** ~~or **DC Converter Station** owner~~ to decide whether to disconnect his **Apparatus** for reasons of safety of **Apparatus**, **Plant** and/or personnel.

ECC.6.3.14X SIMULTANEOUS OVER VOLTAGE AND UNDERFREQUENCY OR SIMULTANEOUS UNDERVOLTAGE AND OVERFREQUENCY

ECC.6.3.14X.1 As stated in ECC.6.1.3, the **System Frequency** could rise to 52Hz or fall to 47Hz and the **System** voltage at the **Connection Point** could rise or fall within the values outlined in CC.6.1.4. **Each Type C and Type D Power Generating Module** ~~**Generating Unit**, **DC Converter**, or **OTSDUW Plant and Apparatus**, Power Park Module~~ or any constituent element must continue to operate within this **Frequency** range for at least the periods of time given in ECC.6.1.3 and voltage range as defined in ECC.6.1.4 unless **NGET** has agreed to any simultaneous overvoltage and underfrequency relays and/or simultaneous undervoltage and over frequency relays ~~or **Frequency** level relays and/or rate-of-change-of **Frequency** relays~~ which will trip such **Power Generating Module**, ~~**Generating Unit**, **DC Converter**,~~ or **OTSDUW Plant and Apparatus**~~, **Power Park Module**~~ and any constituent element within this **Frequency** or voltage range, as specified under the **Bilateral Agreement**.

ECC.6.3.15X RATE OF CHANGE OF FREQUENCY WITHSTAND CAPABILITY

ECC.6.3.15X.1 Each **Type A**, **Type B**, **Type C** and **Type D Power Generating Module** when connected and synchronised to the **Transmission System,** shall be capable of withstanding without tripping a **Rate of Change of Frequency** up to and including 1 Hz per second as measured over a rolling 500 milliseconds period. **Voltage** dips may cause localised **Rate of Change of Frequency** values in excess of 1 Hz per second for short periods, and in these cases, the requirements under ECC.6.3.15 (fault ride through) supersedes this clause. For the avoidance of doubt, this requirement relates to the capabilities of **Power Generating Modules** only and does not impose the need for **Rate of Change of Frequency** protection nor does it impose a specific setting for anti-islanding or loss-of-mains protection relays.

ECC.6.3.16X FAST START CAPABILITY

ECC.6.3.16X.1 It may be agreed in the **Bilateral Agreement** that a **Genset** shall have a **Fast-Start Capability**. Such **Gensets** may be used for **Operating Reserve** and their **Start-Up** may be initiated by **Frequency**-level relays with settings in the range 49Hz to 50Hz as specified pursuant to **OC2**.

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ECC.6.6 SYSTEM MONITORING

ECC.6.6.1 DYNAMIC SYSTEM MONITORING, FAULT RECORDING AND QUALITY OF SUPPLY MONITORING

ECC.6.6.1.1 Each **Type C** and **Type D Power Generating Module** shall be fitted with fault recording and dynamic system monitoring facilities which shall be capable of recording voltage, **Active Power**, **Reactive Power** and **Frequency**.

ECC.6.6.1.2 The settings of the fault recording equipment and dynamic system monitoring equipment (which is required to detect poorly damped power oscillations) including triggering criteria and sampling rates shall be pursuant to the terms of the **Bilateral Agreement.**

ECC.6.6.1.3 **NGET** or **Network Operators** may also specify the requirement for **Generators** in respect of **Type C** and **Type D Power Generating Modules** to install quality of supply monitoring equipment. Any such requirement including the parameters to be monitored would be specified in the **Connection Agreement**.

ECC.6.6.1.4 Provisions for the submission of power quality monitoring and dynamic system monitoring data including communications and protocols shall be agreed between **NGET** and/or **Relevant Transmission Licensees** or **Network Operators** in the **Connection Agreement**.

ECC.6.6.1.5 Any additional requirements in respect of fault recording, power quality monitoring and dynamic system monitoring including additional signal requirements, timing installation, costs, security and other design requirements shall be pursuant to the terms of the **Connection Agreement**.

ECC.6.6.2 FREQUENCY SENSITVE MODE MONITORING IN REAL TIME

ECC.6.6.2.1 **Type C** and **Type D Power Generating Modules** shall be fitted with facilities to record and monitor the operation of **Active Power** frequency response in real time. The monitored data provided at the **Connection Point** shall be secure and capable of being transmitted to the network control centre as specified in the **Connection Agreement**. The monitored data shall include signals of status signal FSM (on/off), scheduled **Active Power** output, actual value of the **Active Power** output, actual parameter settings for **Active Power Frequency Response**, droop and deadband.

ECC.6.6.2.2 **NGET** or **Network Operators** and/or **Relevant Transmission Licensees** shall specify additional signals to be provided by the **Generator** by monitoring and recording devices in order to verify the performance of the **Active Power Frequency** response provision of **Power Generating Modules** which have been instructed in **Frequency Sensitive Mode**.

ECC.6.6.3 COMPLIANCE MONITORING

ECC.6.6.3.1 For all on site monitoring by **NGET** of witnessed tests pursuant to the **CP** or **OC5** the **User** shall provide suitable test signals as outlined in OC5.A.1.

ECC.6.6.3.2 The signals which shall be provided by the **User** to **NGET** for onsite monitoring shall be of the following resolution, unless otherwise agreed by **NGET**:

(i) 1 Hz for reactive range tests

(ii) 10 Hz for frequency control test

(iii) 100 Hz for voltage control tests

ECC.6.6.3.3 The **User** will provide all relevant signals for this purpose in the form of d.c. voltages within the range -10V to +10V. In exceptional circumstances some signals may be accepted as d.c. voltages within the range -60V to +60V with prior agreement between the **User** and **NGET**. All signals shall:

(i) in the case of an **Onshore Power Generating Module**, be suitably terminated in a single accessible location at the **Generator** site.

(ii) in the case of an **Offshore Power Generating Module** and **OTSDUW Plant and Apparatus**, be transmitted onshore without attenuation, delay or filtering which would result in the inability to fully demonstrate the objectives of the test, or identify any potential safety or plant instability issues, and be suitably terminated in a single robust location normally located at or near the onshore **Interface Point** of the **Offshore Transmission System** to which it is connected.

ECC.6.6.3.4 All signals shall be suitably scaled across the range. The following scaling would (unless **NGET** notify the **User** otherwise) be acceptable to **NGET**:

(a) 0MW to **Maximum Capacity** or **Interface Point Capacity** 0-8V dc

(b) Maximum leading **Reactive Power** to maximum lagging **Reactive Power** -8 to 8V dc

(c) 48 – 52Hz as -8 to 8V dc

(d) Nominal terminal or connection point voltage -10% to +10% as -8 to 8V dc

ECC.6.6.3.5 The **User** shall provide to **NGET** a 230V power supply adjacent to the signal terminal location.

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BC.3.7 RESPONSE TO HIGH FREQUENCY REQUIRED FROM SYNCHRONISED GENSETS (AND DC CONVERTERS AT DC CONVERTER STATIONS WHEN TRANSFERRING ACTIVE POWER TO THE TOTAL SYSTEM)

BC3.7.1 Plant In Frequency Sensitive Mode Instructed To Provide High Frequency Response

(a) Each **Synchronised Genset** (or each **DC Converter** at a **DC Converter Station**) in respect of which the **Generator** or **DC Converter Station** owner and/or **EISO** has been instructed to operate so as to provide **High Frequency Response**, which is producing **Active Power** and which is operating above the **Designed Minimum Operating Level**, is required to reduce **Active Power** output in response to an increase in **System Frequency** above the **Target Frequency** (or such other level of Frequency as may have been agreed in an **Ancillary Services Agreement**). The **Target Frequency** is normally 50.00 Hz except where modified as specified under BC3.4.2.

(b) (i) The rate of change of **Active Power** output with respect to **Frequency** up to 50.5 Hz shall be in accordance with the provisions of the relevant **Ancillary Services Agreement** with each **Generator** or **DC Converter Station** owner. If more than one rate is provided for in the **Ancillary Services Agreement NGET** will instruct the rate when the instruction to operate to provide **High Frequency Response** is given.

(ii) The reduction in **Active Power** output by the amount provided for in the relevant **Ancillary Services Agreement** must be fully achieved within 10 seconds of the time of the **Frequency** increase and must be sustained at no lesser reduction thereafter.

(iii) It is accepted that the reduction in **Active Power** output may not be to below the **Designed Minimum Operating Level**.

(c) In addition to the **High Frequency Response** provided, the **Genset** (or **DC Converter** at a **DC Converter Station**) must continue to reduce **Active Power** output in response to an increase in **System Frequency** above 50.5 Hz at a minimum rate of 2 per cent of output per 0.1 Hz deviation of **System Frequency** above that level, such reduction to be achieved within five minutes of the rise to or above 50.5 Hz. For a **Power Station** with a **Completion Date** after 1st January 2009 this reduction in **Active Power** should be delivered in accordance with in (i) to (iv) below. For the avoidance of doubt, the provision of this reduction in **Active Power** output is not an **Ancillary Service**.

(i) The reduction in **Active Power** output must be continuously and linearly proportional as far as practical, to the excess of **Frequency** above 50.5 Hz and must be provided increasingly with time over the period specified in (iii) below.

(ii) As much as possible of the proportional reduction in **Active Power** output must result from the frequency control device (or speed governor) action and must be achieved within 10 seconds of the time of the **Frequency** increase above 50.5 Hz.

(iii) The residue of the proportional reduction in **Active Power** output which results from automatic action of the **Genset** (or **DC Converter** at a **DC Converter Station**) output control devices other than the frequency control devices (or speed governors) must be achieved within 3 minutes from the time of the **Frequency** increase above 50.5 Hz.

(iv) Any further residue of the proportional reduction which results from non-automatic action initiated by the **Generator** or **DC Converter Station** owner shall be initiated within 2 minutes, and achieved within 5 minutes, of the time of the Frequency increase above 50.5 Hz.

BC3.7.2 Plant In Limited Frequency Sensitive Mode

(a) Each **Synchronised Genset** (or **DC Converter** at a **DC Converter Station**) operating in a **Limited Frequency Sensitive Mode** which is producing **Active Power** is also required to reduce **Active Power** output in response to **System Frequency** as required in ECC.6.3.7.1.2 ~~when this rises above 50.4 Hz~~. In the case of **DC Converters** at **DC Converter Stations**, the provisions of BC3.7.7 are also applicable. For the avoidance of doubt, the provision of this reduction in **Active Power** output is not an **Ancillary Service**. Such provision is known as "**Limited High Frequency Response**".

The following text applies to existing generating units only which are not subject to RfG:

~~-~~(b) (i) The rate of change of **Active Power** output must be at a minimum rate of 2 per cent of output per 0.1 Hz deviation of **System Frequency** above 50.4 Hz.

(ii) The reduction in **Active Power** output must be continuously and linearly proportional, as far as is practicable, to the excess of **Frequency** above 50.4 Hz and must be provided increasingly with time over the period specified in (iii) below.

(iii) As much as possible of the proportional reduction in **Active Power** output must result from the frequency control device (or speed governor) action and must be achieved within 10 seconds of the time of the **Frequency** increase above 50.4 Hz.

(iv) The residue of the proportional reduction in **Active Power** output which results from automatic action of the **Genset** (or **DC Converter** at a **DC Converter Station**) *(DC Converter requirements will be defined in the DC Converter section of the CC's)* output control devices other than the frequency control devices (or speed governors) must be achieved within 3 minutes from the time of the **Frequency** increase above 50.4 Hz.

(v) Any further residue of the proportional reduction which results from non-automatic action initiated by the **Generator** or **DC Converter Station** owner shall be initiated within 2 minutes, and achieved within 5 minutes, of the time of the **Frequency** increase above 50.4 Hz.

(vi) Each **Genset** (or **DC Converter** at a **DC Converter Station**) which is providing **Limited High Frequency Response** in accordance with this BC3.7.2 must continue to provide it until the **Frequency** has returned to or below 50.4 Hz or until otherwise instructed by **NGET**.

BC3.7.3 Plant Operation To Below Minimum Generation

(a) As stated in CC.A.3.2, steady state operation below **Minimum Generation** is not expected but if **System** operating conditions cause operation below **Minimum Generation** which give rise to operational difficulties for the **Genset** (or **DC Converter** at a **DC Converter Station**) then **NGET** should not, upon request, unreasonably withhold issuing a **Bid-Offer Acceptance** to return the **Power Generating Module** ~~**Generating Unit** or **CCGT Module** or **Power Park Module**~~ or **DC Converter** to an output not less than **Minimum Generation**. In the case of a **DC Converter** not participating in the **Balancing Mechanism**, then **NGET** will, upon request, attempt to return the **DC Converter** to an output not less than **Minimum Generation** or to zero transfer or to reverse the transfer of **Active Power**.

(b) It is possible that a **Synchronised Genset** (or a **DC Converter** at a **DC Converter Station**) which responded as required under BC3.7.1 or ECC.6.3.7.1 or BC3.7.2 to an excess of **System Frequency**, as therein described, will (if the output reduction is large or if the Genset (or a **DC Converter** at a **DC Converter Station**) output has reduced to below the **Designed Minimum Operating Level**) trip after a time.

(c) All reasonable efforts should in the event be made by **the Generator** or **DC Converter Station** owner to avoid such tripping, provided that the **System Frequency** is below 52Hz.

(d) If the **System Frequency** is at or above 52Hz, the requirement to make all reasonable efforts to avoid tripping does not apply and the **Generator** or **DC Converter Station** owner is required to take action to protect the **Power Generating Modules** ~~**Generating Units**, **Power Park Modules**~~ or **DC Converters** as specified in CC.6.3.13.

(e) In the event of the **System Frequency** becoming stable above 50.5Hz, after all **Genset** and **DC Converter** action as specified in BC3.7.1 and BC3.7.2 has taken place, **NGET** will issue appropriate **Bid-Offer Acceptances** and/or **Ancillary Service** instructions, which may include **Emergency Instructions** under **BC2** to trip **Gensets** (or, in the case of **DC Converters** at **DC Converter Stations**, to stop or reverse the transfer of **Active Power**) so that the **Frequency** returns to below 50.5Hz and ultimately to **Target Frequency**.

(f) If the **System Frequency** has become stable above 52 Hz, after all **Genset** and **DC Converter** action as specified in BC3.7.1, ECC.6.3.7.1 and BC3.7.2 has taken place, **NGET** will issue **Emergency Instructions** under **BC2** to trip appropriate **Gensets** (or in the case of **DC Converters** at **DC Converter Stations** to stop or reverse the transfer of **Active Power**) to bring the **System Frequency** to below 52Hz and follow this with appropriate **Bid-Offer Acceptances** or **Ancillary Service** instructions or further **Emergency Instructions** under BC2 to return the **System Frequency** to below 50.5 Hz and ultimately to **Target Frequency**.

BC.3.7.4 The **Generator** or **DC Converter Station** owner will not be in breach of any of the provisions of BC2 by following the provisions of ECC.6.3.7.1, BC3.7.1, BC3.7.2 or BC3.7.3.

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APPENDIX 3 - MINIMUM FREQUENCY RESPONSE CAPABILITY REQUIREMENT PROFILE AND OPERATING RANGE FOR NEW POWER GENERATING MODULES AND CCGT MODULES

The current text has been taken from Issue 5 Revision 16 of the Grid Code and will require checking to ensure consistency with latest version of the GB Grid Code.

ECC.A.3.1 Scope

Frequency response is defined in two ways within the GB Grid Code and applies to types C and D **Power Generating Modules**

(i) Frequency response capability is defined in terms of the response to a step change in frequency and the ability to respond with an Active Power change satisfying the minimum requirements set out in ECC.6.3.7.3.3.

(ii) Frequency response service is defined in terms of Primary, Secondary and High frequency response profiles. The definitions of these services are illustrated diagrammatically in Figures EC.A.3.2 and EC.A.3.3.

For the avoidance of doubt, this appendix does not apply to **Type A** and **Type B Power Generating Modules**.

The functional definition provides appropriate performance criteria relating to the provision of **Frequency** control by means of **Frequency** sensitive generation in addition to the other requirements identified in ECC.6.3.7.

In this Appendix 3 to the ECC, for a **Power Generating Module** including a **CCGT Module** or a **Power Park Module** with more than one **Generating Unit**, the phrase **Minimum Generation** applies to the entire **CCGT Module** or **Power Park Module** operating with all **Generating Units Synchronised** to the **System**.

The minimum **Frequency** response requirement profile is shown diagrammatically in Figure ECC.A.3.1. The capability profile specifies the minimum required level of **Frequency Response** Capability throughout the normal plant operating range.

ECC.A.3.2 Plant Operating Range

The upper limit of the operating range is the **Maximum Capacity** of the **Power Generating Module** or **Generating Unit** or **CCGT Module** or ~~**DC Converter**~~ or **Power Park Module**.

The **Minimum Generation** level may be less than, but must not be more than, 65% of the **Maximum Capacity**. Each **Power Generating Module** and/or **Generating Unit** and/or **CCGT Module** and/or **Power Park Module** ~~and/or **DC Converter**~~ must be capable of operating satisfactorily down to the **Designed Minimum Operating Level** as dictated by **System** operating conditions, although it will not be instructed to below its **Minimum Generation** level. If a **Power Generating Module** or **Generating Unit** or **CCGT Module** or **Power Park Module** ~~or **DC Converter**~~ is operating below **Minimum Generation** because of high **System Frequency**, it should recover adequately to its **Minimum Generation** level as the **System Frequency** returns to **Target Frequency** so that it can provide **Primary** and **Secondary Response** from **Minimum Generation** if the **System Frequency** continues to fall. For the avoidance of doubt, under normal operating conditions steady state operation below **Minimum Generation** is not expected. The **Designed Minimum Operating Level** must not be more than 55% of **Maximum Capacity**.

In the event of a **Power Generating Module** or **Generating Unit** or **CCGT Module** or **Power Park Module** ~~or **DC Converter**~~ load rejecting down to no less than its **Designed Minimum Operating Level** it should not trip as a result of automatic action as detailed in BC3.7. If the load rejection is to a level less than the **Designed Minimum Operating Level** then it is accepted that the condition might be so severe as to cause it to be disconnected from the **System**.

ECC.A.3.3 Minimum Frequency Response Requirement Profile

Figure ECC.A.3.1 shows the minimum **Frequency** response capability requirement profile diagrammatically for a 0.5 Hz change in **Frequency**. The percentage response capabilities and loading levels are defined on the basis of the **Maximum Capacity** of the **Power Generating Module** or **CCGT Module** ~~or **DC Converter**~~. Each **Power Generating Module** or and/or **CCGT Module** ~~and/or **DC Converter**~~ must be capable of operating in a manner to provide **Frequency** response at least to the solid boundaries shown in the figure. If the **Frequency** response capability falls within the solid boundaries, the **Power Generating Module** or **CCGT Module** ~~or **DC Converter**~~ is providing response below the minimum requirement which is not acceptable. Nothing in this appendix is intended to prevent a **Power Generating Module** or **CCGT Module** ~~or **DC Converter**~~ from being designed to deliver a **Frequency** response in excess of the identified minimum requirement.

The **Frequency** response delivered for **Frequency** deviations of less than 0.5 Hz should be no less than a figure which is directly proportional to the minimum **Frequency** response requirement for a **Frequency** deviation of 0.5 Hz. For example, if the **Frequency** deviation is 0.2 Hz, the corresponding minimum **Frequency** response requirement is 40% of the level shown in Figure ECC.A.3.1. The **Frequency** response delivered for **Frequency** deviations of more than 0.5 Hz should be no less than the response delivered for a **Frequency** deviation of 0.5 Hz.

Each **Power Generating Module** and/or **CCGT Module** ~~and/or **DC Converter**~~ must be capable of providing some response, in keeping with its specific operational characteristics, when operating between 95% to 100% of **Maximum Capacity** as illustrated by the dotted lines in Figure ECC.A.3.1.

At the **Minimum Generation** level, each **Power Generating Module** and/or **CCGT Module** ~~and/or **DC Converter**~~ is required to provide high and low frequency response depending on the **System Frequency** conditions. Where the **Frequency** is high, the **Active Power** output is therefore expected to fall below the **Minimum Generation** level.

The **Designed Minimum Operating Level** is the output at which a **Power Generating Module** and/or **CCGT Module** ~~and/or **DC Converter**~~ has no **High Frequency Response** capability. It may be less than, but must not be more than, 55% of the **Maximum Capacity**. This implies that a **Power Generating Module** or **CCGT Module** ~~or **DC Converter**~~ is not obliged to reduce its output to below this level unless the **Frequency** is at or above 50.5 Hz (cf BC3.7).

ECC.A.3.4 Testing Of Frequency Response Capability

The frequency response capabilities shown diagrammatically in Figure ECC.A.3.1 are measured by taking the responses as obtained from some of the dynamic step response tests specified by **NGET** and carried out by **Generators** ~~and **DC Converter Station** owners~~ for compliance purposes. The injected signal is a step of 0.5Hz *(an additional diagram may be required here)* from zero to 0.5 Hz **Frequency** change ~~over a ten second period~~, and is sustained at 0.5 Hz **Frequency** change thereafter, the latter as illustrated diagrammatically in figures ~~ECC.A.3.2 and ECC.A.3.3~~ ECC.A.3.4 and ECC.A.3.5.

In addition to provide and/or to validate the content of **Ancillary Services Agreements** a progressive injection of a **Frequency** change to the plant control system (i.e. governor and load controller) is used. The injected signal is a ramp of 0.5Hz from zero to 0.5 Hz **Frequency** change over a ten second period, and is sustained at 0.5 Hz **Frequency** change thereafter, the latter as illustrated diagrammatically in figures ECC.A.3.2 and ECC.A.3.3. In the case of an **Embedded Medium Power Station** not subject to a **Bilateral Agreement** ~~or **Embedded DC Converter Station** not subject to a **Bilateral Agreement**~~, **NGET** may require the **Network Operator** within whose **System** the **Embedded Medium Power Station** or ~~**Embedded DC Converter Station**~~ is situated, to ensure that the **Embedded Person** performs the dynamic response tests reasonably required by **NGET** in order to demonstrate compliance within the relevant requirements in the **CC**. For the avoidance of doubt, these tests will be conducted with ramp signals for the purposes of determining **Primary, Secondary and High Frequency Responses**.

The **Primary Response** capability (P) of a **Power Generating Module** or a **CCGT Module** ~~**or DC Converter**~~ is the minimum increase in **Active Power** output between 10 and 30 seconds after the start of the ramp injection as illustrated diagrammatically in Figure ECC.A.3.2. This increase in **Active Power** output should be released increasingly with time over the period 0 to 10 seconds from the time of the start of the **Frequency** fall as illustrated by the response from Figure ECC.A.3.2.

The **Secondary Response** capability (S) of a **Power Generating Module** or a **CCGT Module** ~~**or DC Converter**~~ is the minimum increase in **Active Power** output between 30 seconds and 30 minutes after the start of the ramp injection as illustrated diagrammatically in Figure ECC.A.3.2.

The **High Frequency Response** capability (H) of a **Power Generating Module** or a **CCGT Module** ~~**or DC Converter**~~ is the decrease in **Active Power** output provided 10 seconds after the start of the ramp injection and sustained thereafter as illustrated diagrammatically in Figure ECC.A.3.3. This reduction in **Active Power** output should be released increasingly with time over the period 0 to 10 seconds from the time of the start of the **Frequency** rise as illustrated by the response in Figure ECC.A.3.2.

ECC.A.3.5 Repeatability Of Response

When a **Power Generating Module** or **CCGT Module** ~~**or DC Converter**~~ has responded to a significant **Frequency** disturbance, its response capability must be fully restored as soon as technically possible. Full response capability should be restored no later than 20 minutes after the initial change of **System Frequency** arising from the **Frequency** disturbance.

Figure ECC.A.3.1 - Minimum Frequency Response Requirement Profile for a 0.5 Hz frequency change from Target Frequency

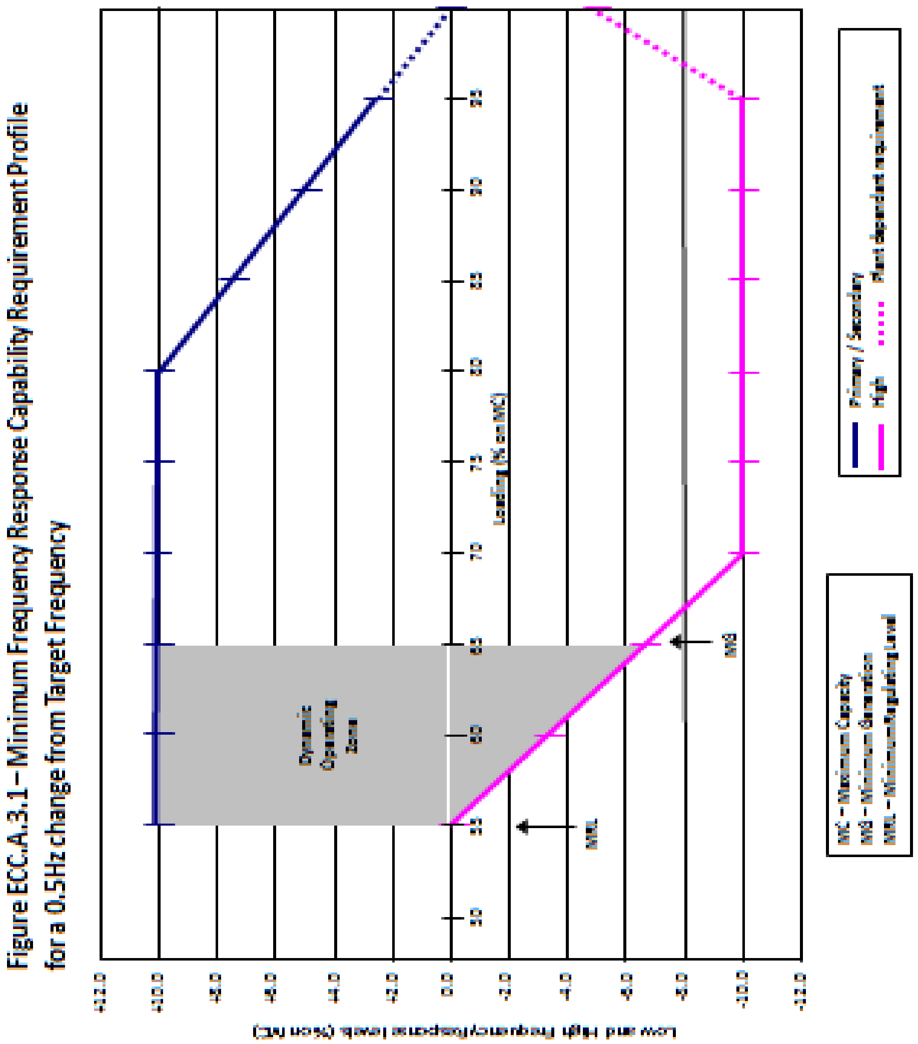


Figure ECC.A.3.2 - Interpretation of Primary and Secondary Response Values

Figure ECC.A.3.2 – Interpretation of Primary and Secondary Response Service Values

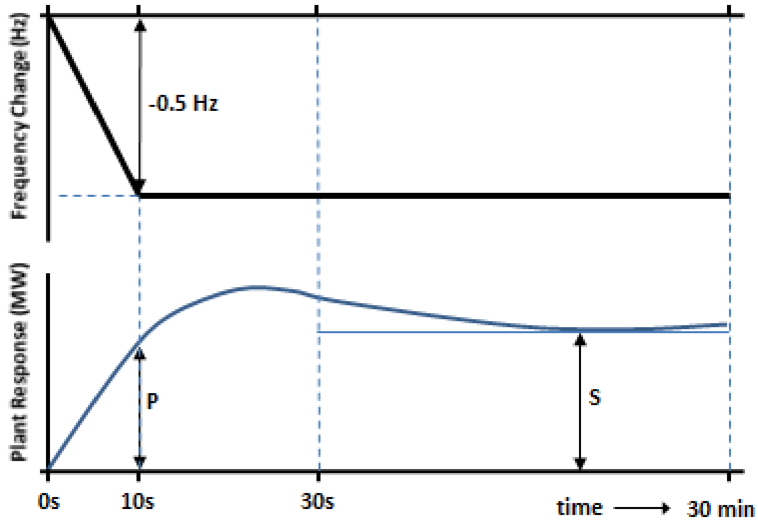
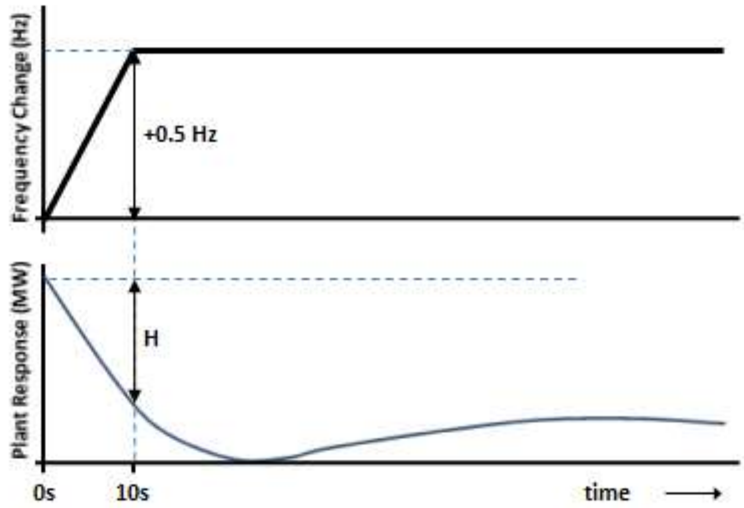


Figure ECC.A.3.3 - Interpretation of High Frequency Response Values

Figure ECC.A.3.3 – Interpretation of High Frequency Response Service Values



New Figure ECC.A.3.5 – Interpretation of Low Frequency Response Capability Values

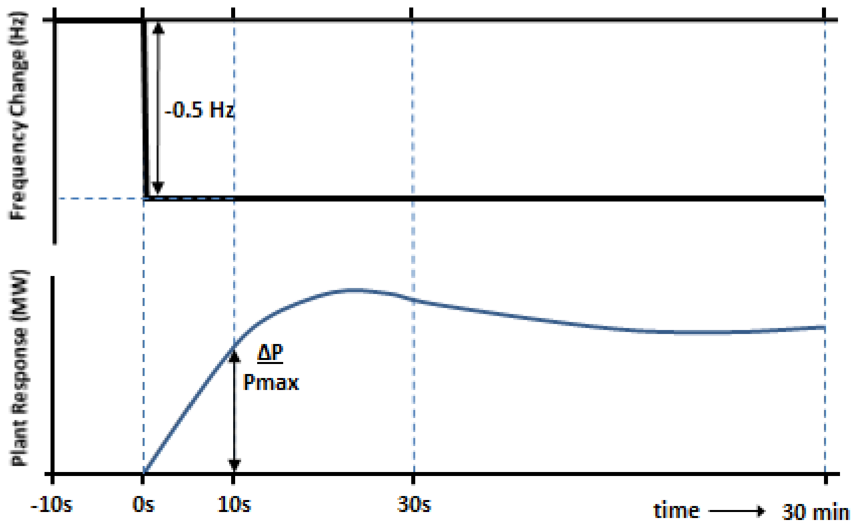
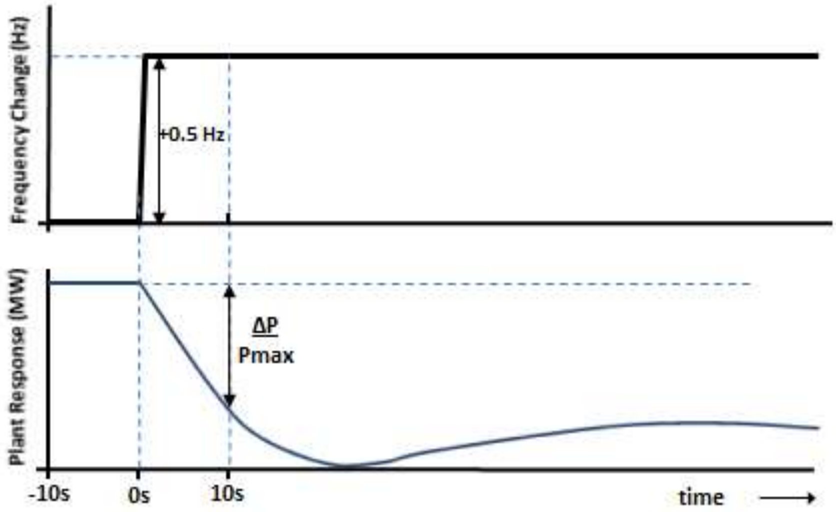


Figure ECC.A.3.5 – Interpretation of High Frequency Response Capability Values



RFG FREQUENCY – ISSUES TABLE

No	Article	Issue	Comments
1	General	OTSDUW DC Converter	OTSDUW Plant and Apparatus is in scope of frequency response drafting but OTSDUW DC Converters will be included in HV DC Converter requirements
2	Art 15 (5)(a)(vi)	Block Load	Do we need to link block load as referred to in RfG to Block Load Capability as defined in the GB Grid Code.
3	Art 15 (5)(a)(vi)	Definitions	Consistency checks required
4	Art 15(2)(a)	Time periods for Active Power Control and tolerance	These issues should be covered in the BC's and OC's and hence reference those sections of the Code. It is however not clear how this would get picked up via the D Code
5	Art 15(2)(b)	Local Measures where automatic control devices are out of service	This looks like a new requirement "Manual local measures shall be allowed in cases where the automatic remote control devices are out of service "The relevant Network Operator or the Relevant TSO shall notify the regulatory authority of the time required to reach the setpoint together with the tolerance for active power.– do we need to refer to it in the code.
6	Art 15 (2)(d)(i)	Frequency Insensitivity and Deadband	Frequency Insensitivity has been set to ±15mHz and deadband set to zero
7	Art 15 (2)(d)(iii)	FSM Peformance	Superfluous text ("which shall aim at avoiding active power oscillations and technology dependent limitations into account") has been removed as these are more a factor of the parameters selected rather than anything else.
8	Art 15 (2)(d)(v)(vi)	Derivation of full Active Power between 15 – 30 minutes	Not sure this is required as we define Primary and Secondary Frequency response
9	Art 15 (2)(d)(vii)	Frequency Response Parameters – Notification to Regulatory Authority	Not sure this text is required as it should be covered as part of the GB Governance process.
10	Art 15 (2)(f)	Reference to Pumped Storage	Need a new term in the GB G&D's to cover Pumped Storage Power

		Plant	Generating Modules
11	CC.6.3.9	Definition of Genset	Definition of Genset requires amendment / updating in GB Code.
12	CC.A.3	Definitions –Generating Unit / Power Park Module / CCGT Module	Suggest we still use the GB terms of Generating Unit / Power Park Module and CCGT Module. All of which could form part of a Power Generating Module but it will need a change to the GB Glossary and Definitions
13	CC.A.3	DC Converters	Not sure if we should leave this in and refer to it when we deal with the DC Converter requirements
14	CC.A.3	Reference to Embedded Medium Power Stations not subject to an Bilateral Agreement	This is the old LEEMPS term which we are still likely to use for Type C plant. Are we still comfortable with this arrangement or do the words need changing.
15	CC.A.3	Do we need to cover step changes as well in CC.A.3	RfG covers step changes. CC.A.3 covers Ramp changes. Do we need to include step changes in CC.A.3 to cover RfG.
16	Art 15(6)(b)	Dynamic System Monitoring	The obligation refers to the Power Generating Facility not the Power Generating Module – Does this need checking with ENTSO-E. An alternative would be to state Generators in respect of Type C and D Power Generating Modules
17	Art 15(6)(b)	DSM, PQM and Fault Recording	Re-written in consistent GB language. This may different from the exact words in RfG but has or should have the same meaning.
18	Art 15(2)(g)	Real-time monitoring of FSM	Re-written in consistent GB language. This may different from the exact words in RfG but has or should have the same meaning.
19		BC3	Requirements for LFSM-O have been included in ECC's but there is a conflict with New / Existing and how the BC's should be written going forwards in a EU world.

Draft G99 text applicable to Frequency Issues (G99 is the replacement for G59 which is the technical specifications for embedded generation greater than 5MW connected at or above 20kV)

Purple text = from G59

Brown/Orange text = from RfG (June 2015)

Green text = from other EU documents referenced by RfG

Blue text = from Distribution Code

Black text = Changes/ additional words

Red text = Words that may/ will need changing

A complete review of the Glossary and Definitions will be required when the full suite of European Codes has been implemented. The current assumption is to use GB definitions where appropriate with use of European definitions where required. A consistency check will also be required between the Glossary and Definitions in the Grid Code and those in the Distribution Code.

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9.3 Power Generating Module Performance and Control Requirements

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9.3.4 **Type A** P**ower generating modules** connected to the **DNO's Distribution Network** shall be equipped with a logic interface (input port) in order to cease **active power** output within five seconds following an **instruction** being received at the input port. The relevant **DNO** has the right to define requirements for equipment to make this facility operable remotely.

9.3.5 To control active power output, **Type B Power Generating Nodules** shall be equipped with an interface (input port) in order to be able to reduce active power output following an instruction at the input port. The **DNO** shall have the right to specify the requirements for further equipment to allow active power output to be remotely operated.

9.3.6 Each item of a **Power Generating Module** and its associated control equipment must be designed for stable operation in parallel with the **Distribution Network**.

…..

Frequency response

9.4.1 Under abnormal conditions automatic low-frequency load-shedding provides for load reduction down to 47Hz. In exceptional circumstances, the frequency of the **DNO's Distribution Network** could rise above 50.5 Hz. Therefore all embedded **Power Generating Facilities** should be capable of continuing to operate in parallel with the **Distribution Network** in accordance with the following:

a. 47 Hz – 47.5 Hz Operation for a period of at least 20 seconds is required each time the frequency is within this range.

b. 47.5 Hz – 49.0 Hz Operation for a period of at least 90 minutes is required each time the frequency is within this range.

c. 49.0Hz – 51.0 Hz The **Power Generating Module** must remain connected in this range

d. 51.0 Hz –51.5 Hz Operation for a period of at least 90 minutes is required each time the frequency is within this range.

e. 51.5 Hz – 52 Hz Operation for a period of at least 15 minutes is required each time the frequency is within this range.

9.4.1 Output power with falling frequency

Power Generating Module, must be capable of:

(a) continuously maintaining constant **Active Power** output for **System Frequency** changes within the range 50.5 to 49.5 Hz; and

(b) (subject to the provisions of paragraph 9.4.1) maintaining its **Active Power** output at a level not lower than the figure determined by the linear relationship shown in Figure 9.1 for **System Frequency** changes within the range 49.5 to 47 Hz for all ambient temperature changes up to and including 25^{0}C, such that if the **System Frequency** drops to 47 Hz the **Active Power** output does not decrease by more than 5%. In the case of a **CCGT Module**, the above requirement shall be retained down to 48.8 Hz. For **System Frequency** below 48.8 Hz, the existing requirement shall be retained for a minimum period of 5 minutes while **System Frequency** remains below that setting, and special measure(s) that may be required to meet this requirement shall be kept in service during this period. After that 5 minutes period, if **System Frequency** remains below that setting, the special measure(s) must be discontinued if there is a materially increased risk of the **Gas Turbine** tripping. The need for special measure(s) is linked to the inherent **Gas Turbine Active Power** output reduction caused by reduced shaft speed due to falling **System Frequency**. Where the need for special measures is identified in order to maintain output in line with the level identified in Figure 9.1 these measures should be still continued at ambient temperatures above 25^{0}C maintaining as much of the **Active Power** achievable within the capability of the plant.

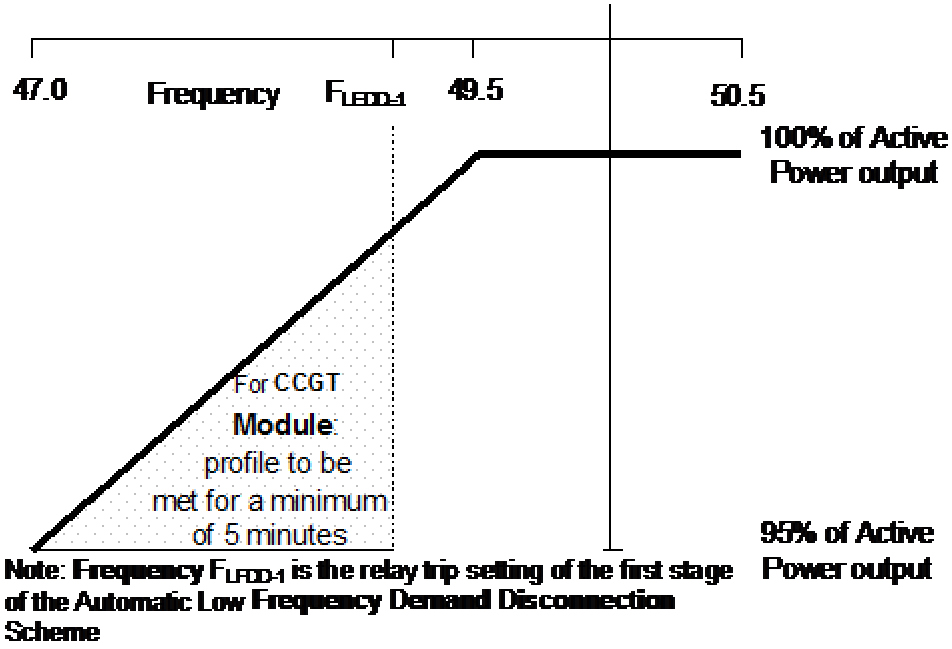

Figure 9.1

9.5 Limited Frequency Sensitive Mode – Overfrequency

9.5.1 Each **Power Generating Module** shall be capable of reducing **Active Power** output in response to **System Frequency** when this rises above 50.4Hz. For the avoidance of doubt, the provision of this reduction in **Active Power** output is not an **Ancillary Service**. Such provision is known as **Limited High Frequency Response**. The **Power Generating Module** shall be capable of operating stably during **LFSM-O** operation. When **LFSM-O** is active, the **LFSM-O** setpoint will prevail over any other active power setpoints.

9.5.2 (i) 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 (ie a Droop of 10%) as shown in Figure 9.2 below.

(ii) The reduction in **Active Power** output must be continuously and linearly proportional, as far as is practicable, to the excess of **Frequency** above 50.4 Hz and must be provided increasingly with time over the period specified in (iii) below.

(ii) The **Power Generating Module** shall be capable of initiating a **Power Frequency** response with minimal delay. If the delay exceeds 2 seconds the **Generator** shall justify the delay, providing technical evidence to the DNO.

Active power frequency response capability of power-generating modules in LFSM-O

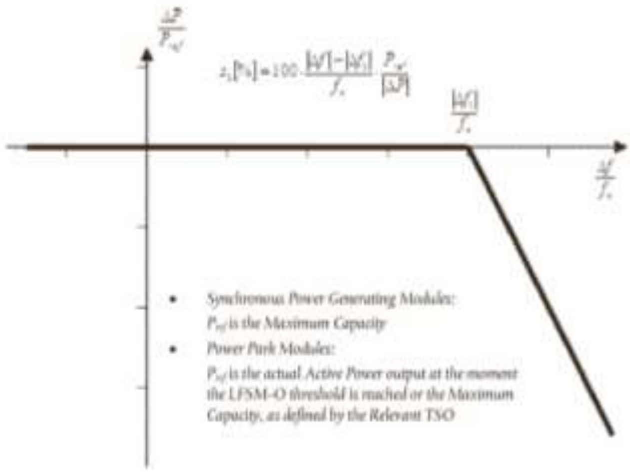

Figure 9.2: Pref is the reference active power to which ΔP is related and may be specified differently for **Synchronous Power Generating Modules** and **Power Park Modules**. ΔP is the change in **Active Power** output from the **Power Generating Module**. Fn is the nominal frequency (50Hz) in the network and Δf is the **Frequency** deviation in the network, At overfrequencies where Δf is below Δf_1 the **Power Generating Module** has to provide a negative **Active Power** output change according to droop S_2 which shall be no greater than 10%.

~~9.5.3~~ ~~For power generating modules connected to the DNO's Distribution Network below 110 kV and with a maximum capacity of less than 1 MW (Type A) automatic disconnection and reconnection at randomised frequencies may be allowed by the relevant TSO where it is able to demonstrate to the Authority, and with the cooperation of power generating module owners, that this has a limited cross-border impact and maintains the same level of operational security in all system states;~~

9.5.4 The **Power Generating Module** shall be capable of activating a power frequency response with an initial delay that is as short as possible. If that delay is greater than two seconds, the power generating facility owner shall justify the delay, providing technical evidence to the **TSO**;

9.5.5 The TSO may require that upon reaching minimum regulating level, the **Power Generating Module** be capable of either:

(i) continuing operation at this level; or

(ii) further decreasing **Active Power output**;

9.5.6 The power generating module shall be capable of operating stably during LFSM-O operation. When LFSM-O is active, the LFSM-O setpoint will prevail over any other Active Power setpoints.

9.14 Island Mode

9.14.1 A fault or planned outage, which results in the disconnection of a **Power Generating Module**, together with an associated section of **Distribution Network**, from the remainder of the **Total System**, creates the potential for island mode operation. It will be necessary for the **DNO** to decide, dependent on local network conditions, if it is desirable for the **Users** to continue to generate onto the islanded **DNO's Distribution Network**. The key potential advantage of operating in Island Mode is to maintain continuity of supply to the portion of the **Distribution Network** containing the **Power Generating Module**. The principles discussed in this section generally also apply where **Generation Plant** on a **Customer**'s site is designed to maintain supplies to that site in the event of a failure of the **DNO** supply.

9.14.2 When considering whether **Power Generating Modules** can be permitted to operate in island mode, detailed studies need to be undertaken to ensure that the islanded system will remain stable and comply with all statutory obligations and relevant planning standards when separated from the remainder of the **Total System**. Before operation in island mode can be allowed, a contractual agreement between the **DNO** and **Power Generating Facility Owner** must be in place and the legal liabilities associated with such operation must be carefully considered by the **DNO** and the **Power Generating Facility Owner**. Consideration should be given to the following areas:

a. load flows, voltage regulation, frequency regulation, voltage unbalance, voltage flicker and harmonic voltage distortion;

b. earthing arrangements;

c. short circuit currents and the adequacy of protection arrangements;

d. **System Stability**;

e. resynchronisation to the **Total System**;

f. safety of personnel.

9.14.3 Suitable equipment will need to be installed to detect that an island situation has occurred and an intertripping scheme is preferred to provide absolute discrimination at the time of the event. Confirmation that a section of **Distribution Network** is operating in island mode, and has been disconnected from the **Total System**, will need to be transmitted to the **Power Generating Module(s)** protection and control schemes.

9.14.4 The **ESQCR** requires that supplies to **Customers** are maintained within statutory limits at all times ie when they are supplied normally and when operating in island mode. Detailed system studies including the capability of the **Power Generating Module** and its control / protections systems will be required to determine the capability of the **Power Generating Module** to meet these requirements immediately as the island is created and for the duration of the island mode operation.

……..

9.16 **Technical Requirements for Type C Power Generating Modules**

Where a **Power Generating Facility Owner** in respect of a **Power Generating Module** connected to the DNO network is a party to the **CUSC** this section 9.16 will not apply.

9.15 **Black Start Capability**

The **National Electricity Transmission System** will be equipped with **Black Start Stations** (in accordance with the **Distribution Operating Code** DOC 9). It will be necessary for each User to notify the DNO if its **Power Generating Module** has a restart capability without connection to an external power supply, unless the **User** shall have previously notified the **TSO** accordingly under the **Grid Code**. Such generation may be registered by the **TSO** as a **Black Start Station**.

9.16.1.1 In addition to the requirements in this document, the **DNO** has an obligation under ECC 3.3 of the **Grid Code** to ensure that all relevant **Grid Code** Connection Condition requirements are met by **Embedded Type C Power Generating Modules**. These requirements are summarised in ECC 3.3 of the **Grid Code**. It is incumbent on **Embedded Type C Power Generating Modules** to comply with the relevant **Grid Code** requirements listed in ECC3.4 of the **Grid Code** as part of compliance with this **Distribution Code**.

9.16.1.2 Where data is required by **NETSO** from Embedded **Type C Power Generating** Modules, nothing in the **Grid Code** or **Distribution Code** precludes the **Power Generating Facility Owner** from providing the information directly to **NETSO** in accordance with **Grid Code** requirements. However, a copy of the information should always be provided in parallel to the **DNO**.

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Annex 4 – Distribution Code Legal Text

Draft G99 text for Section 9 Network Connection Design and Operation

NOTE:- THIS SECTION HAS BEEN PROVIDED IN GOOD FAITH FOR INFORMATION ONLY IN ORDER TO GIVE AN INDICATION OF THE STRUCTURE OF SECTION 9 OF G99. IT IS NOT PART OF THIS CONSULTATION AND COMMENTS ARE NOT REQUESTED ON THE TECHNICAL CONTENT OF THIS TEXT.

Purple text = from G59

Brown/Orange text = from RfG (June 2015)

Green text = from other EU documents referenced by RfG

Blue text = from Distribution Code

Black text = Changes/ additional words

Red text = Words that may/ will need changing

9 NETWORK CONNECTION DESIGN AND OPERATION

General Criteria

9.1

9.1.1 As outlined in Section 5, **DNO**s have to meet certain statutory and **Distribution Licence** obligations when designing and operating their **Distribution Networks**. These obligations will influence the options for connecting **Power Generating Modules**.

9.1.2 The **DNO** has a duty to develop and maintain an efficient, secure and co-ordinated **Network** of electricity supply that is both economical and safe.

9.1.3 **This Section** sets out current principles and standards to be applied in the design of the **DNO's Distribution Network** and any **User** connections to that **Network.** Each scheme for reinforcement or modification of the **DNO's Distribution Network** is individually designed in the light of economic and technical features associated with the particular **System** limitations under consideration.

9.1.4 Nothing in this section is intended to inhibit design innovation**.** This Section is, therefore, based upon the performance requirements of the **DNO's Distribution Network** necessary to meet the above criteria.

9.1.5 The technical and design criteria to be applied in the design of the **Distribution Network** and **Power Generating Module** connection are detailed in this document. The criteria are based upon the performance requirements of the **Distribution Network** necessary to meet the above obligations. These standards may be subject to revision from time to time in accordance with the provision of the **Distribution Licence**.

9.1.6 The **Distribution Network**, and any **Power Generating Module** connection to that network, shall be designed,

a. to comply with the obligations (to include security, frequency and voltage; voltage disturbances and harmonic distortion; auto reclosing and single phase protection operation).

b. according to design principles in relation to **Distribution Network**'s plant and equipment, earthing, voltage regulation and control, and protection as outlined in this section, subject to any modification to which the **DNO** may reasonably consent.

9.1.7 **Power Generating Modules** should meet a set of technical requirements in relation to its performance with respect to frequency and voltage, control capabilities, protection coordination requirements, phase voltage unbalance requirements, neutral earthing provisions, islanding and **black start capability**. These requirements are listed in this section.

9.1.8 There are additional performance requirements that are specified in the **Grid Code** for all embedded **Power Generating Facilities** comprising **Power Generating Modules** greater than 50 MW. The requirements for Type C **Power Generating Modules** are referenced in section 9.16, and are all listed in ECC3.3 to ECC3.5 of the **Grid Code**. For Embedded Type D **Power Generating Modules** the **Grid Code** generally applies in full.

9.1.9 In accordance with Condition 14 of its **Distribution Licence** the **DNO**, on the request of a **User,** will prepare a statement showing present and future circuit capacity, forecast power flows and loading on the part or parts of the **DNO's Distribution Network** specified in the request and **Fault Levels** at each distribution node covered by the request and containing:

a) such further information as shall be reasonably necessary to enable such person to identify and evaluate the opportunities available when connecting to and making use of the part or parts of the licensee's distribution network specified in the request ;and

b) if so requested, a commentary prepared by the licensee indicating the licensee's views as to the suitability of the part or parts of the licensee's distribution network specified in the request for new connections and the distribution of further quantities of electricity..

The **Distribution Licence** sets out conditions on the time scales and charges associated with providing such a statement

9.1.10 In accordance with Condition 25 of its Distribution Licence the **DNO** will prepare on the request of the **Authority** a statement, also known as the Long Term Development Statement. The form and content of this statement will be specified by the **Authority** and will cover future years on a rolling basis. This statement gives information to assist any person who contemplates entering into distribution arrangements with the **DNO** to identify and evaluate the opportunities for doing so.

9.2 Network Connection Design for Power Generating Modules

9.2.1 The connection of new **Customer**s, including **Power Generating Facility Owner**s, to the **Distribution Network** should not generally increase the risk of interruption to existing **Customers**. For example, alterations to existing **Distribution Network** designs that cause hitherto normally closed circuits to have to run on open standby such that other **Customers** might become disconnected for the duration of the auto-switching times are deprecated.

9.2.2 Connection of **Power Generating Modules** to **Distribution Networks** will be subject to rules for managing the complexity of circuits. For example EREC P18 sets out the normal limits of complexity of 132kV circuits by stipulating certain restrictions to be applied when they are designed e.g. the operation of protective gear for making dead any 132kV circuit shall not require the opening of more than seven circuit breakers and these circuit breakers shall not be located at more than four different sites. Each DNO will have similar policies for managing complexity of lower voltage circuits.

9.2.3 The security requirements for the connection of **Power Generating Modules** are subject to economic consideration by the **DNO** and the **Power Generating Facility**

Owner. A firm connection for **Power Generating Module** should allow the full MVA capacity to be exported via the **Distribution Network** at all times of year and after one outage on any one circuit of the **Distribution Network**. ETR 124 provides additional advice on the management of constraints and security.

9.2.4 The decision as to whether or not a firm connection is required should be by agreement between the **DNO** and the **Power Generating Facility Owner**. The **DNO** should be able to provide an indication of the likely duration and magnitude of any constraints so that the **Power Generating Facility Owner** can make an informed decision. The **Power Generating Facility Owner** should consider the financial implications of a non-firm connection against the cost of a firm connection, associated **Distribution Network** reinforcement and the risk of any constraints due to **Distribution Network** restrictions.

9.2.5 Where the **DNO** expects the **Power Generating Module** to contribute to system security, the provisions of EREC P2 and the guidance of ETR 130 will apply. In addition, the **Power Generating Module** should either remain synchronised and in parallel with the **Distribution Network** under the outage condition being considered or be capable of being resynchronised within the time period specified in EREC P2. There may be commercial issues to consider in addition to the connection cost and this may influence the technical method which is used to achieve a desired security of supply.

9.2.6 When designing a scheme to connect **a Power Generating Module**, consideration must be given to the contribution which that **Power Generating Module** will make to short circuit current flows on the **Distribution Network**. The assessment of the fault level contribution from **a Power Generating Module** and the impact on the suitability of connected switchgear are discussed in Section 9.4.

9.2.7 It is clearly important to avoid unwanted tripping of the **Power Generating Module** particularly where the **Power Generating Module** is providing **Distribution Network** or **Total System** security. The quality of supply and stability of **Power Generating Module** performance are dealt with in Sections 9.6 and 9.7 respectively.

9.2.8 **Power Generating Modules** may be connected via existing circuits to which load and/or existing **Power Generating Modules are** also connected. The duty on such circuits, including load cycle, real and reactive power flows, and voltage implications on the **Distribution Network** will need to be carefully reviewed by the **DNO**, taking account of maximum and minimum load and generation export conditions during system intact conditions and for maintenance outages of both the **Distribution Network** and **Generation Plant**. In the event of network limitations, ETR 124 provides guidance to **DNO**s on overcoming such limitations using active management solutions.

9.2.9 A **DNO** assessing a proposed connection of **a Power Generating Module** must also consider its effects on the **Distribution Network** voltage profile and voltage control employed on the **Distribution Network**. Voltage limits and control issues are discussed in Section 9.5.

9.3 Power Generating Module Performance and Control Requirements

9.3.1 The requirements of this section do not apply to **Power Generation Facilities** that are designed and installed for infrequent short term parallel operation only.

9.3.2 The design of and any changes to the schemes and settings of the different control devices of a **power generating module** with a **maximum capacity** of more than 1 MW (Type B and above) that are necessary for transmission **system stability** and for taking emergency action shall be coordinated and agreed between NETSO, the **DNO** and the **power generating facility owner**.

9.3.3 For **Embedded Power Generating Modules,** which do not constitute or contain **BM Units** that are active (ie submitting bid-offer data) in the **Balancing Mechanism**, the electrical parameters required to be achieved at the **Generation Set** terminals are defined according to the connection method and will be specified by the **DNO** with the offer for connection. The rated power output of a **Power Generating Module** should not be affected by voltage changes within the statutory limits declared by the **DNO** in accordance with the **ESQCR** unless otherwise agreed with the **DNO**.

9.3.4 Type A P**ower generating modules** connected to the **DNO's Distribution Network** shall be equipped with a logic interface (input port) in order to cease **active power** output within five seconds following an **instruction** being received at the input port. The relevant **DNO** has the right to define requirements for equipment to make this facility operable remotely.

9.3.5 To control active power output, Type B **Power Generating Nodules** shall be equipped with an interface (input port) in order to be able to reduce active power output following an instruction at the input port. The **DNO** shall have the right to specify the requirements for further equipment to allow active power output to be remotely operated.

9.3.6 Each item of a **Power Generating Module** and its associated control equipment must be designed for stable operation in parallel with the **Distribution Network**.

9.3.7 The **Power Generating Facility Owner** will notify, and keep notified, the **DNO** of the set points of the control scheme for voltage control or Power Factor control as appropriate and which have previously been agreed between the **Power Generating Facility Owner** and **DNO**. The information to be provided is detailed in Schedule 5a and Schedule 5b.

9.3.8 Load flow and **System Stability** studies may be necessary to determine any output constraints or post fault actions necessary for n-1 fault conditions and credible n-2 conditions (where n-1 and n-2 conditions are the first and second outage conditions as, for example, specified in EREC P2) involving a mixture of fault and planned outages. The **Connection Agreement** should include details of the relevant outage conditions. It may be necessary under these fault conditions, where the combination of **Power Generating Module** output, load and through flow levels leads to circuit overloading, to rapidly disconnect or constrain the **Power Generating Module** .

Frequency response

9.4.1 Under abnormal conditions automatic low-frequency load-shedding provides for load reduction down to 47Hz. In exceptional circumstances, the frequency of the **DNO's Distribution Network** could rise above 50.5 Hz. Therefore all embedded **Power Generating Facilities** should be capable of continuing to operate in parallel with the **Distribution Network** in accordance with the following:

f. 47 Hz – 47.5 Hz Operation for a period of at least 20 seconds is required each time the frequency is within this range.

g. 47.5 Hz – 49.0 Hz Operation for a period of at least 90 minutes is required each time the frequency is within this range.

h. 49.0Hz – 51.0 Hz The **Power Generating Module** must remain connected in this range

i. 51.0 Hz –51.5 Hz Operation for a period of at least 90 minutes is required each time the frequency is within this range.

j. 51.5 Hz – 52 Hz Operation for a period of at least 15 minutes is required each time the frequency is within this range.

9.4.1 <u>Output power with falling frequency</u>

Each **Power Generating Module**, must be capable of:

(a) continuously maintaining constant **Active Power** output for **System Frequency** changes within the range 50.5 to 49.5 Hz; and

(b) (subject to the provisions of paragraph 9.4.1) maintaining its **Active Power** output at a level not lower than the figure determined by the linear relationship shown in Figure 9.1 for **System Frequency** changes within the range 49.5 to 47 Hz for all ambient temperature changes up to and including 25^{0}C, such that if the **System Frequency** drops to 47 Hz the **Active Power** output does not decrease by more than 5%. In the case of a **CCGT Module**, the above requirement shall be retained down to 48.8 Hz. For **System Frequency** below 48.8 Hz, the existing requirement shall be retained for a minimum period of 5 minutes while **System Frequency** remains below that setting, and special measure(s) that may be required to meet this requirement shall be kept in service during this period. After that 5 minutes period, if **System Frequency** remains below that setting, the special measure(s) must be discontinued if there is a materially increased risk of the **Gas Turbine** tripping. The need for special measure(s) is linked to the inherent **Gas Turbine Active Power** output reduction caused by reduced shaft speed due to falling **System Frequency**. Where the need for special measures is identified in order to maintain output in line with the level identified in Figure 9.1 these measures should be still continued at ambient temperatures above 25^{0}C maintaining as much of the Active Power achievable within the capability of the plant.

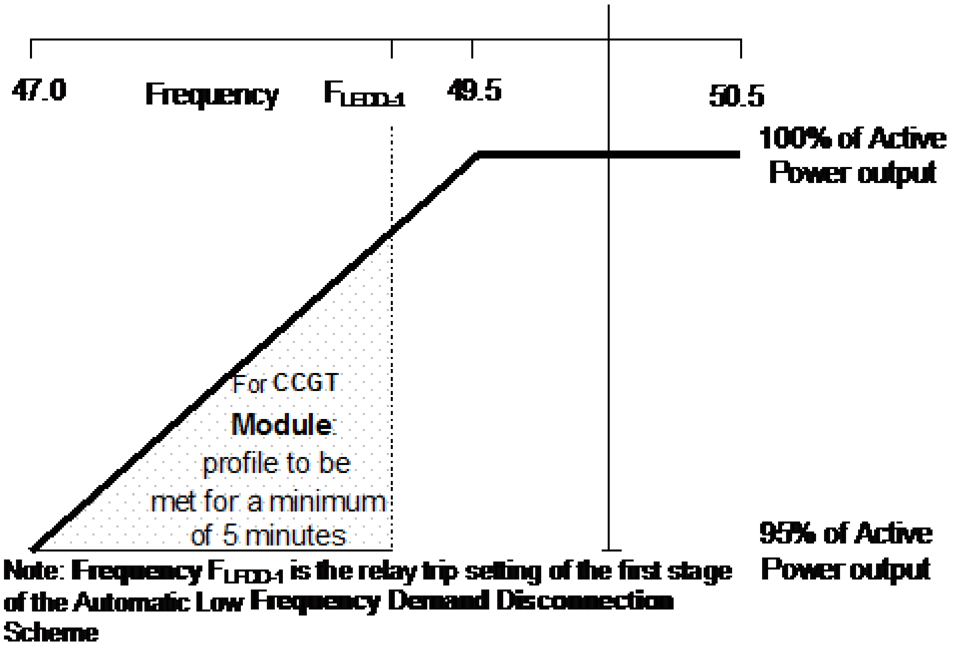

Figure 9.1

9.5 Limited Frequency Sensitive Mode – Overfrequency

9.5.1 Each **Power Generating Module** shall be capable of reducing **Active Power** output in response to **System Frequency** when this rises above 50.4Hz. For the avoidance of doubt, the provision of this reduction in **Active Power** output is not an **Ancillary Service**. Such provision is known as **Limited High Frequency Response**. The **Power Generating Module** shall be capable of operating stably during **LFSM-O** operation. When **LFSM-O** is active, the **LFSM-O** setpoint will prevail over any other active power setpoints.

9.5.2 (iii) 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 (ie a Droop of 10%) as shown in Figure 9.2 below.

(ii) The reduction in Active Power output must be continuously and linearly proportional, as far as is practicable, to the excess of Frequency above 50.4 Hz and must be provided increasingly with time over the period specified in (iii) below.

(iv) The Power Generating Module shall be capable of initiating a Power Frequency Response with minimal delay. If the delay exceeds 2 seconds the Generator shall justify the delay, providing technical evidence to the DNO.

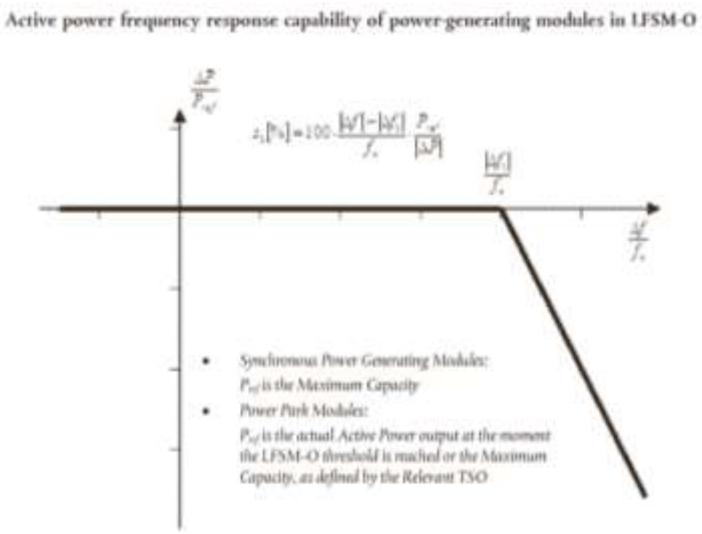

Figure 9.2: Pref is the reference active power to which ΔP is related and may be specified differently for **Synchronous Power Generating Modules** and **Power Park Modules**. ΔP is the change in **Active Power** output from the **Power Generating Module**. Fn is the nominal frequency (50Hz) in the network and Δf is the **Frequency** deviation in the network, At overfrequencies where Δf is below Δf_1 the **Power Generating Module** has to provide a negative **Active Power** output change according to droop S_2

9.5.3 For power generating modules connected to the DNO's Distribution Network below 110 kV and with a maximum capacity of less than 1 MW (Type A) automatic disconnection and reconnection at randomised frequencies may be allowed by the relevant TSO where it is able to demonstrate to the Authority, and with the cooperation of power generating module owners, that this has a limited cross-border impact and maintains the same level of operational security in all system states;

9.5.4 The power generating module shall be capable of activating a power frequency response with an initial delay that is as short as possible. If that delay is greater than two seconds, the power generating facility owner shall justify the delay, providing technical evidence to the **TSO**;

9.5.5 The TSO may require that upon reaching minimum regulating level, the power generating module be capable of either:

(i) continuing operation at this level; or

(ii) further decreasing **active power output**;

9.5.6 The power generating module shall be capable of operating stably during LFSM-O operation. When LFSM-O is active, the LFSM-O setpoint will prevail over any other active power setpoints.

9.6 Fault Contributions and Switchgear Considerations

9.6.1 Under the **ESQCR** 2002 and the EaWR 1989 the **Power Generating Facility Owner** and the **DNO** have legal duties to ensure that their respective systems are capable of withstanding the short circuit currents associated with their own equipment and any infeed from any other connected system.

9.6.1.1 The short circuit rating of **User's Equipment** at the **Connection Point** should be not less than the design **Fault Level** of the **DNO's Distribution Network** to which it is connected. The choice of **Equipment** for connection at **Low Voltage** may take into account attenuation in the service lines as specified in Engineering Recommendation P25, "The short circuit characteristics of electricity board's low voltage distribution networks and the co-ordination of overcurrent protective devices on 230V single phase supplies up to 100 Amps" and Engineering Recommendation P26/1, "The estimation of the maximum prospective short circuit current for three phase 415V supplies". The **DNO** in the design of its **Network** will take into account the contribution to **Fault Level** of the **User's** connected **System** and **Apparatus**.

9.6.1.2 In order to permit these assessments to be carried out information should be exchanged on prospective fault power infeed and X/R ratios where appropriate at points of entry to and exit from the **DNO's Distribution Network.**

9.6.2 The **Power Generating Facility Owner** may accept that protection installed on the **Distribution Network** can help discharge some of his legal obligations relating to fault clearance and, if requested, the **DNO** should consider allowing such faults on the **Power Generating Facility Owner's** system to be detected by **DNO** protection systems and cleared by the **DNO**'s circuit breaker. The **DNO** will not allow the **Power Generating Facility Owner** to close the **DNO**'s circuit breaker nor to synchronise using the **DNO**'s circuit breaker. In all such cases the exact nature of the protection afforded by the **DNO**'s equipment should be agreed and documented. The **DNO** may make a charge for the provision of this service.

9.6.3 The design and safe operation of the **Power Generating Facility Owner**'s and the **DNO**'s installation's depend upon accurate assessment of the contribution to the short circuit current made by all the **Power Generating Modules** operating in parallel with the **Distribution Network** at the instant of fault and the **Power Generating Facility Owner** should discuss this with the **DNO** at the earliest possible stage.

9.6.4 Short circuit current calculations should take account of the contributions from all synchronous and asynchronous infeeds including induction motors and the contribution from inverter connected **Power Generating Module**s. The prospective short circuit 'make' and 'break' duties on switchgear should be calculated to ensure that plant is not potentially over-stressed. The maximum short circuit duty might not occur under maximum generation conditions; it may occur during planned or automatic operations carried out either on the **Distribution Network** or **Transmission System**. Studies must therefore consider all credible **Distribution Network** running arrangements which are likely to increase **Distribution Network** short circuit levels. The level of load used in the assessment should reflect committed projects as well as the existing loads declared in the **DNO**'s Long Term Development Statement (LTDS). Guidance on short circuit calculations is given in EREC G74.

9.6.5 The connection of **a Power Generating Module** can raise the **Distribution Network** reactance/resistance (X/R) ratio. In some cases, this will place a more onerous duty on switchgear by prolonging the duration of the DC component of fault current from fault inception. This can increase the proportion of the DC component of the fault current and delay the occurrence of current zeros with respect to voltage zeros during the interruption of fault current. The performance of connected switchgear must be assessed to ensure safe operation of the **Distribution Network**. The performance of protection may also be impaired by partial or complete saturation of current transformers resulting from an increase in **Distribution Network** X/R ratio.

9.6.6 Newly installed protection systems and circuit breakers for **Power Generating Module** connections should be designed, specified and operated to account for the possibility of out-of-phase operation. It is expected that the **DNO's** metering/interface circuit breaker will be specified for this duty, but in the case of existing circuit breakers on the **Distribution Network**, the **DNO** will need to establish the possibility or otherwise of the **DNO**s protection (or the **Power Generating Facility Owner**'s protection if arranged to trip the **DNO's** circuit breaker) initiating a circuit breaker trip during a period when one of more **Power Generating Module**s might have lost **Synchronism** with the **Total System**. Where necessary, switchgear replacement, improved security arrangements and other control measures should be considered to mitigate this risk.

9.6.7 When connection of **a Power Generating Module** is likely to increase short circuit currents above **Distribution Network** design ratings, consideration should be given to the installation of reactors, sectionalising networks, connecting the **Power Generating Module** to part of the **Distribution Network** operating at a higher voltage, changing the **Power Generating Module** specification or other means of limiting short circuit current infeed. If fault limiting measures are not cost effective or feasible or have a material detrimental effect on other users, **Distribution Network** plant with the potential to be subjected to short circuit currents in excess of its rating should be replaced or reference made to the relevant manufacturer to determine whether or not the existing plant rating(s) can be enhanced. In situations where **Distribution Network** design ratings would be exceeded in infrequent but credible **Distribution Network** configurations, then constraining the **Power Generating Module** off during periods of such **Distribution Network** configurations may provide a suitable solution. When assessing short circuit currents against **Distribution Network** design ratings, suitable safety margins should be allowed to cater for tolerances that exist in the **Distribution Network** data and **Power Generating Module** parameters used in system modelling programs. On request from a **Power Generating Facility Owner** the **DNO** will provide the rationale for determining the value of a specific margin being used in **Distribution Network** studies.

9.6.8 For busbars with three or more direct connections to the rest of the **Total System**, consideration may be given to reducing fault levels by having one of the connections 'open' and on automatic standby. This arrangement will only be acceptable provided that the loss of one of the remaining circuits will not cause the group to come out of **Synchronism**, cause unacceptable voltage excursions or overloading of **Distribution Network** or **Transmission System** plant and equipment. The use of the proposed **Power Generating Module** to prevent overloading of **Distribution Network** plant and equipment should be considered with reference to EREC P2.

9.6.9 Disconnection of **a Power Generating Module** must be achieved by the separation of mechanical contacts unless the disconnection is at **Low Voltage** and the equipment at the point of disconnection contains appropriate self-monitoring of the point of disconnection, in which case an appropriate electronic means such as a suitably rated semiconductor switching device would be acceptable. The self-monitoring facility shall incorporate fail safe monitoring to check the voltage level at the output stage. In the event that the solid state switching device fails to disconnect the **Power Generating Module**, the voltage on the output side of the switching device shall be reduced to a value below 50V within 0.5s. For the avoidance of doubt this disconnection is a means of providing LoM disconnection and not as a point of isolation to provide a safe system of work.

9.6.10

Capacitive and Inductive Effects

The **User** shall, when applying to make a connection, provide the **DNO** with information as detailed in DPC8. Details will be required of capacitor banks and reactors connected at **HV** which could affect the **DNO's Distribution Network** and which it is proposed to connect if agreed by the **DNO**. When requested by the **DNO** details shall also be provided of distributed circuit capacitance and inductance. Sufficient detail is required for the following:-

(a) To verify that controlling **Equipment** of the **DNO's Distribution Network** is suitably rated.

(b) To show that the performance of the **DNO's Distribution Network** will not be impaired.

(c) To ensure that arc suppression coils when used by the **DNO** for **System** earthing purposes are correctly installed and operated.

9.7

Fault Ride through

9.7.1 Paragraphs 9.7.1 to 9.7.8 inclusive set out the fault ride through, principles and concepts applicable to Type B **Synchronous Power Generating Modules** and **Power Park Modules**, subject to disturbances from faults on the transmission system of up to 140ms in duration.

9.7.2 Each **Synchronous Power Generating Module** and **Power Park Module** is required to remain connected and stable for any balanced and unbalanced fault where the voltage at the **Connection Point** remains on or above the heavy black line shown in Figures 9.3 and 9.4 below.

9.7.3 The voltage against time curves defined in 9.7.4 – 9.7.7 expresses the lower limit (expressed as the ratio of its actual value and its reference 1pu) of the actual course of the phase to phase voltages (or phase to earth voltage in the case of asymmetrical/unbalanced faults) on the network voltage level at the **Connection Point** during a symmetrical or asymmetrical/unbalanced fault, as a function of time before, during and after the fault.

9.7.4

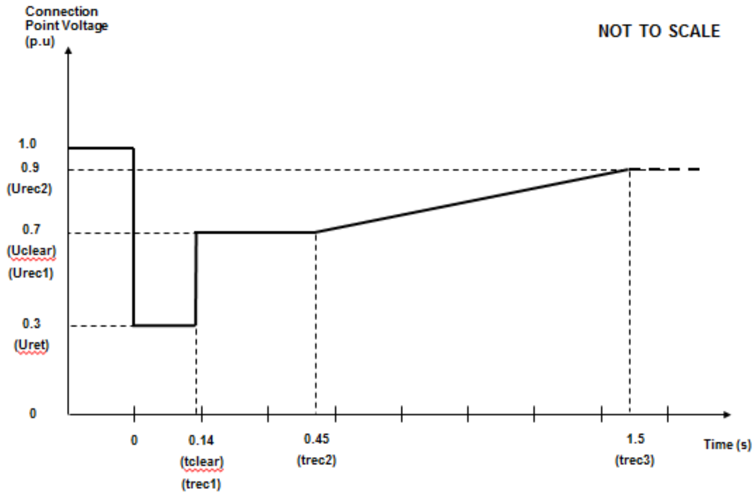

Figure 9.3 - Voltage against time curve applicable to Type B **Synchronous Power Generating Modules**

9.7.5 Voltage against time parameters applicable to Type B **Synchronous Power Generating Modules**

Voltage parameters (pu)		**Time parameters (seconds)**	
Uret	0.3	tclear	0.14
Uclear	0.7	trec1	0.14
Urec1	0.7	trec2	0.45
Urec2	0.9	trec3	1.5

9.7.6

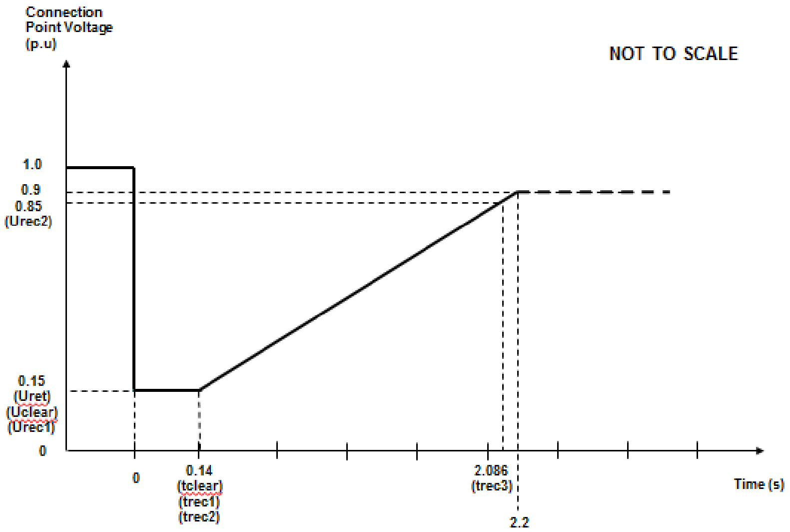

Figure 9.4 - Voltage against time curve applicable to Type B **Power Park Modules**

9.7.7 Voltage against time parameters applicable to Type B **Power Park Modules**

Voltage parameters (pu)		**Time parameters (seconds)**	
Uret	0.15	tclear	0.14
Uclear	0.7	trec1	0.14
Urec1	0.7	trec2	0.45
Urec2	0.9	trec3	1.5

9.7.8 In addition to the requirements in 9.7.4 to 9.7.7:

(a) Each Type B **Power Generating Module** shall be capable of satisfying the above requirements when operating at **Rated MW** output and maximum leading **Power Factor**.

(b) The pre-fault voltage shall be taken to be 1.0pu and the post fault voltage shall be 0.9pu unless a higher value is specified in the Connection Agreement.

(c) **The DNO** will publish fault level data under maximum and minimum demand conditions in the Long Term Development Statements. To allow a **User** to model the fault ride through performance of its Type B **Power Generating Modules**, **the DNO** will provide generic fault level values derived from typical cases. Where necessary, on reasonable request the DNO will specify the pre-fault and post fault short circuit capacity (in MVA) at the **Connection Point** and will provide additional network data as may reasonably be required for the **User** to undertake such study work.

(d) Each **Generator** shall satisfy the requirements in 9.7.4 – 9.7.7 unless the protection schemes and settings for internal electrical faults requires disconnection of the Type B **Power Generating Module** from the network. The protection schemes and settings should not jeopardise fault ride through performance as specified in 9.7.4 – 9.7.7. The undervoltage protection at the **Connection Point** shall be set by the **Power Generating Facility Owner** according to the widest possible range unless **the DNO** has agreed to narrower settings which shall be pursuant to the terms of the **Connection Agreement**. All protection settings associated with undervoltage protection shall be agreed between the DNO and the Power Generating Facility Owner.

(e) In addition to the requirements of 9.7.4 – 9.7.8 each Type B **Power Generating Module** shall be designed such within 0.5 seconds of restoration of the voltage at the **Connection Point** to 90% of nominal voltage or greater, **Active Power** output shall be restored to at least 90% of the level immediately before the fault. Once **Active Power** output has been restored to the required level, **Active Power** oscillations shall be acceptable provided that:

- 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
- The oscillations are adequately damped.

(f) For Type B **Power Park Modules**, comprising switched reactive compensation equipment (such as mechanically switched capacitors and reactors), such switched reactive compensation equipment shall be controlled such that it is not switched in or out of service during the fault but may act to assist in post fault voltage recovery.

9.7.9 In addition to paragraphs 9.7.1 – 9.7.8 any **Power Generating Module** or **Power Generating Facility** connected to the **DNO's Distribution Network**, where it has been agreed between the **DNO** and the **Power Generating Facility Owner** that the **Power Generating Facility** will contribute to the **DNO**'s **Distribution Network** security, may be required to withstand, without tripping, the effects of a close up three phase fault and the Phase (Voltage) Unbalance imposed during the clearance of a close-up phase-to-phase fault , in both cases cleared by the **DNO**'s main protection. The **DNO** will advise the **Embedded Power Generating Facility** in each case of the likely tripping time of the **DNO**'s protection, and for phase-phase faults, the likely value of Phase (Voltage) Unbalance during the fault clearance time.

In the case of phase to phase faults on the **DNO**'s system that are cleared by **System** back-up **Protection** which will be within the **Plant** short time rating on the **DNO**'s **Distribution Network** the **DNO**, on request during the Connection Agreement process, will advise the Embedded Power Generating Facility Owner of the expected Phase Voltage Unbalance.

9.8 Voltage Limits and Control

9.8.1 Where **a Power Generating Module** is remote from a network voltage control point it may be required to withstand voltages outside the normal statutory limits. In these circumstances, the **DNO** should agree with the **Power Generating Facility Owner** the declared voltage and voltage range at the **Connection Point**. Immunity of the **Power Generating Module** to voltage changes of ± 10% of the declared voltage is recommended, subject to design appraisal of individual installations.

9.8.2 The connection of a **Power Generating Module** to the **Distribution Network** shall be designed in such a way that operation of the **Power Generating Module** does not adversely affect the voltage profile of and voltage control employed on the **Distribution Network**. ETR 126 provides **DNO**s with guidance on active management solutions to overcome voltage control limitations. Information on the voltage regulation and control arrangements will be made available by the **DNO** if requested by the **User.**

9.8.3 When supplying **Rated MW** all Type B **Power Generating Modules** must be capable of continuous operation at any points between the limits of 0.95 Power Factor lagging and 0.95 Power Factor leading at the **Connection Point** unless otherwise specified by the **DNO** in the **Connection Agreement.**

9.8.4 At Active Power output levels other than **Rated MW**, all alternators within a Type B **Synchronous Power Generating Modules** must be capable of continuous operation at any point between the Reactive Power capability limits identified on the **Generator Performance Chart** unless otherwise agreed with the **DNO**.

9.8.5 At Active Power output levels other than **Rated MW**, all Type B **Power Park Modules** must be capable of continuous operation at any point between the **Reactive Power** capability limits identified on the P-Q operating chart unless otherwise agreed with the **DNO**.

9.8.6 Each Type B **Synchronous Power Generating Module** shall be equipped with a permanent automatic excitation system that can provide constant alternator terminal voltage at a selectable setpoint without instability over the entire operating range of the Type B Synchronous **Power Generating Module**.

9.8.7 The **DNO** will specify in the **Connection Agreement** if the control system of the Type B **Synchronous Power Generating Module** or **Power Park Module** shall contribute to voltage control or Reactive Power control or Power Factor control at the **Connection Point** (or other defined busbar). The performance requirements of the control system including droop (where applicable) shall be specified in the **Connection Agreement**.

9.8.8 The final responsibility for control of **Distribution Network** voltage does however remain with the **DNO**.

9.8.9 Automatic Voltage Control (AVC) schemes employed by the **DNO** assume that power flows from parts of the **Distribution Network** operating at a higher voltage to parts of the **Distribution Network** operating at lower voltages. Export from **Power Generating Modules** in excess of the local loads may result in power flows in the reverse direction. In this case AVC referenced to the low voltage side will not operate correctly without an import of reactive power and relay settings appropriate to this operating condition. When load current compounding is used with the AVC and the penetration level of **Power Generating Modules** becomes significant compared to normal loads, it may be necessary to switch any compounding out of service.

9.8.10 **Power Generating Modules** can cause problems if connected to networks employing AVC schemes which use negative reactance compounding and line drop compensation due to changes in active and reactive power flows. ETR 126 provides guidance on connecting generation to such networks using techniques such as removing the generation circuit from the AVC scheme using cancellation CTs.

9.8.11 An agreement between the **DNO** and the **Power Generating Facility Owner** may allow the use of voltage control techniques other than those previously mentioned. Such an agreement would normally be reached during the negotiating stage of the connection.

9.8.12 The **Step Voltage Change** caused by the connection and disconnection of **Power Generating Modules** from the **Distribution Network** must be considered and be subject to limits to avoid unacceptable voltage changes being experienced by other **Customers** connected to the **Distribution Network**. The magnitude of a **Step Voltage Change** depends on the method of voltage control, types of load connected and the presence of local generation.

Typical limits for **Step Voltage Change** caused by the connection and disconnection of any **Customers** equipment to the **Distribution Network** should be ± 3% for infrequent planned switching events or outages in accordance with EREC P28. For unplanned outages such faults it will generally be acceptable to design to a **Step Voltage Change** of ±10%.

A voltage step change should be considered to be the change from the initial voltage level to the resulting voltage level after all the **Power Generating Module automatic voltage regulator** and static VAR compensator actions, and transient decay (typically 5 seconds after the fault clearance or system switching) have taken place, but before any other automatic or manual tap-changing and switching actions have commenced

9.8.13 The voltage depression arising from transformer magnetising inrush current is a short-time phenomenon not generally easily captured by the definition of **Step Voltage Change** used in this document. In addition the size of the depression is dependent on the point on wave of switching and the duration of the depression is relatively short in that the voltage recovers substantially in less than one second.

9.8.14 **Customer Installation**s should be designed such that transformer magnetising inrush current associated with normal routine switching operations does not cause voltage fluctuations outside those in EREC P28 (i.e. a maximum of ±3%). To achieve this it may be necessary to install switchgear so that sites containing multiple transformers can be energised in stages.

9.8.15 Situations will arise from time to time when complete sites including a significant presence of transformers are energised as a result of post fault switching, post fault maintenance switching, carrying out commissioning tests on **Distribution Network** or on the **Customer**'s **Installation**. In these situations it will generally be acceptable to design to an expected depression of around 10% recognising that a worst case energisation might be a larger depression, on the basis that such events are considered to be rare and it is difficult to predict the exact depression because of the point on wave switching uncertainty. Should these switching events become more frequent than once per year then the design should revert to aiming to limit depressions to less than 3%.

9.8.16 These threshold limits should be complied with at the **Point of Common Coupling** as required by EREC P28.

9.9 Voltage Disturbances

Under fault and circuit switching conditions the rated **Frequency** component of voltage may fall or rise transiently. The fall or rise in voltage will be affected by the method of earthing of the neutral point of the **DNO's Distribution Network** and voltage may fall transiently to zero at the point of fault. BS EN 50160:2010 'Voltage Characteristics of Electricity Supplied by Public Distribution Systems', as amended from time to time, contains additional details of the variations and disturbances to the voltage which shall be taken into account in selecting **Equipment** from an appropriate specification for installation on or connected to the **System**.

9.10 **Voltage Stability**

9.10.1 The **DNO** in coordination with **NGET** shall have the right to specify that a Type B **Power Park Module** that is connected to the **DNO's Distribution Network** be capable of providing **fast fault current** at the **connection point** in case of symmetrical (3-phase) faults, under the following conditions:

9.10.2 (i) the **Power Park Module** shall be capable of activating the supply of **fast fault current** either by:

- ensuring the supply of the **fast fault current** at the connection point; or
- measuring voltage deviations at the terminals of the individual units of the power park module and providing a **fast fault current** at the terminals of these units;

9.10.3 (ii) the **DNO** in coordination with **NGET** shall specify:

- how and when a voltage deviation is to be determined as well as the end of the voltage deviation;
- the characteristics of the **fast fault current**, including the time domain for measuring the voltage deviation and fast fault current, for which current and voltage may be measured differently from the following methods;
  - voltage measured as the root-mean-square value of the positive sequence phase-to-phase voltages at fundamental frequency;
  - current measured by the root-mean-square value of the positive sequence of the phase current at fundamental frequency.

– the timing and accuracy of the **fast fault current**, which may include several stages during a fault and after its clearance;

9.10.4 With regard to the supply of fast fault current in case of asymmetrical (1-phase or 2-phase) faults, the **DNO** in coordination with **NETSO** shall have the right to specify a requirement for asymmetrical current injection.

9.11 **Additional Requirements**

9.11.1 **Type B Power Park Modules** shall fulfil the following additional requirements in relation to robustness:

(a) providing post-fault **active power** recovery to meet **the TSO's** specification including:

(i) when the post-fault **active power** recovery begins, based on a voltage criterion;

(ii) a maximum allowed time for **active power** recovery; and

(iii) a maximum allowed time for **active power** recovery.

9.11.2 (b) the specifications shall be in accordance with the following principles:

- (i) interdependency between **fast fault current** requirements according to Paragraphs 9.10.3 to 9.10.5 and active power recovery;
- (ii) dependence between **active power** recovery times and duration of voltage deviations;
- (iii) a specified limit of the maximum allowed time for **active power** recovery;
- (iv) adequacy between the level of voltage recovery and the minimum magnitude for **active power** recovery; and
- (v) adequate damping of active power oscillations.

9.12 Power Quality

9. 12.1 Introduction

The connection and operation of **Power Generating Modules** may cause a distortion of the **Distribution Network** voltage waveform resulting in voltage fluctuations, harmonics or phase voltage unbalance.

9. 12.2 Flicker

Where the input motive power of the **Power Generating Module** may vary rapidly, causing corresponding changes in the output power, flicker may result. The operation of a **Power Generating Module** including synchronisation, run-up and desynchronisation shall not result in flicker that breaches the limits for flicker in EREC P28.

The fault level of the **Distribution Network** needs to be considered to ensure that the emissions produced by the **Power Generating Module** do not cause a problem on the **Distribution Network**.

The **DNO** will use these declared figures to calculate the required maximum supply impedance required for the connection to comply with EREC P28. This calculation may show that the voltage fluctuations will be greater than those permitted and hence reinforcement of the **Distribution Network** may be required before the **Power Generating Module** can be connected.

9. 12.2.1 For wind turbines, flicker testing should be carried out during the performance tests specified in BS EN 61400-12. Flicker data should be recorded from wind speeds of $1ms^{-1}$ below cut-in to 1.5 times 85% of the rated power. The wind speed range should be divided into contiguous bins of $1ms^{-1}$ centred on multiples of $1ms^{-1}$. The dataset shall be considered complete when each bin includes a minimum of 10 minutes of sampled data.

The highest recorded values across the whole range of measurements should be used as inputs to the calculations described in BS EN 61000-3-11 to remove back ground flicker values. Then the required maximum supply impedance values can be calculated as described in 13.1. Note that occasional very high values may be due to faults on the associated HV network and may be discounted, though care should be taken to avoid discounting values which appear regularly.

9. 12.2 For technologies other than wind, the controls or automatic programs used shall produce the most unfavourable sequence of voltage changes for the purposes of the test.

9. 12.3 Harmonic Emissions

Harmonic voltages and currents produced within the **Power Generating Facility Owner**'s system may cause excessive harmonic voltage distortion in the **Distribution Network**. The **Power Generating Facility Owner**'s installation must be designed and operated to comply with the planning criteria for harmonic voltage distortion as specified in EREC G5. EREC G5, like all planning standards referenced in this recommendation, is applicable at the time of connection of additional equipment to a **Customer**'s **Installation**.

The **DNO** will use these declared figures to calculate the required maximum supply impedance required for the connection to comply with BS EN 61000-3-12 and will use this data in their design of the connection for the **Power Generating**

Module. This standard requires a minimum ratio between source fault level and the size of the **Power Generating Module**, and connections in some cases may require the installation of a transformer between 2 and 4 times the rating of the **Power Generating Module** in order to accept the connection to a **DNO's Distribution Network.**

Alternatively, if the harmonic emissions are low and they are shown to meet the requirements of BS EN 61000-3-2 then there will be no need to carry out the fault level to **Power Generating Module** size ratio check. **Power Generating Module**s meeting the requirements of BS EN 61000-3-2 will need no further assessment with regards to harmonics.

9. 12.4 Where the **Power Generating Module** is connected via a long cable circuit the likelihood of a resonant condition is greatly increased, especially at 132kV. This arises from the reaction of the transformer inductance with the cable capacitance. Resonance is likely in the low multiples of the fundamental frequency (8th-11th harmonic). The resonant frequency is also a function of the **Total System** fault level. If there is the possibility that this can change significantly eg by the connection of another **Power Generating Module** then a full harmonic study should be carried out.

9. 12.5 Voltage imbalance

EREC P29 is a planning standard which sets the **Distribution Network** compatibility levels for voltage unbalance caused by uneven loading of three phase supply systems. **Power Generating Module**s should be capable of performing satisfactorily under the conditions it defines. The existing voltage unbalance on an urban **Distribution Network** rarely exceeds 0.5% but higher levels, in excess of 1%, may be experienced at times of high load and when outages occur at voltage levels above 11kV. 1% may exist continuously due to unbalance of the system impedance (common on remote rural networks). In addition account can be taken of the neutralising effect of rotating plant, particularly at 11 kV and below.

9. 12.6 The level of voltage unbalance at the **Point of Common Coupling** should be no greater than 1.3% for systems with a nominal voltage below 33kV, or 1% for other systems with a nominal voltage no greater than 132kV. Overall, voltage unbalance should not exceed 2% when assessed over any one minute period. EREC P29, like all planning standards, is applicable at the time of connection.

9. 12.6.1 For **Power Generating Facilities** of 50kW or less section 7.5 of this document specifies maximum unbalance of **Power Generating Modules**. Where these requirements are met then no further action is required by the **Power Generating Facility Owner**.

9. 12.7 Power factor correction equipment is sometimes used with asynchronous **Power Generating Module**s to decrease reactive power flows on the **Distribution Network**. Where the power factor correction equipment is of a fixed output, stable operating conditions in the event of loss of the **DNO** supply are extremely unlikely to be maintained, and therefore no special protective actions are required in addition to the standard protection specified in this document.

9. 12.8 DC Injection

The effects of, and therefore limits for, DC currents injected into the **Distribution Network** is an area currently under investigation by **DNO**s. Until these investigations are concluded the limit for DC injection is less than 0.25% of the AC rating per **Power Generating Module**.

The main source of these emissions are from transformer-less **Inverters**. Where necessary DC emission requirements can be satisfied by installing a transformer on the AC side of an **Inverter**.

9.13 System Stability

9.13.1 Instability in **Distribution Networks** may result in unacceptable quality of supply and tripping of **Customer**'s plant. In severe cases, instability may cascade across the **Distribution Network**, resulting in widespread tripping and loss of demand and generation. There is also a risk of damage to plant.

9. 13.2 In general, **System Stability** is an important consideration in the design of **Power Generating Module** connections to the **Distribution Network** at 33kV and above. Stability considerations may also be appropriate for some **Power Generating Module** connections at lower voltages. The risks of instability generally increase as **Power Generating Module** capacity increases relative to the fault level infeed from the **Distribution Network** at the **Connection Point**.

9. 13.3 **System Stability** may be classified into several forms, according firstly to the main system variable in which instability can be observed, and secondly to the size of the system disturbance. In **Distribution Networks**, the forms of stability of interest are rotor angle stability and voltage stability.

Rotor angle stability refers to the ability of synchronous machines in an interconnected system to remain in **Synchronism** after the system is subjected to a disturbance.

Voltage stability refers to the ability of a system to maintain acceptable voltages throughout the system after being subjected to a disturbance.

9. 13.4 Both rotor angle stability and voltage stability can be further classified according to the size of the disturbance.

Small-disturbance stability refers to the ability of a system to maintain stability after being subjected to small disturbances such as small changes in load, operating points of **Power Generating Module**s, transformer tap-changing or other normal switching events.

Large-disturbance stability refers to the ability of a system to maintain stability after being subjected to large disturbances such as short-circuit faults or sudden loss of circuits or **Power Generating Module**s.

9. 13.5 Traditionally, large-disturbance rotor angle stability (also referred to as transient stability) has been the form of stability predominantly of interest in **Distribution Network**s with synchronous machines. However, it should be noted that the other forms of stability may also be important and may require consideration in some cases.

9. 13.6 It is recommended that **a Power Generating Module** and its connection to the **Distribution Network** be designed to maintain stability of the **Distribution Network** for a defined range of initial operating conditions and a defined set of system disturbances.

The range of initial operating conditions should be based on those which are reasonably likely to occur over a year of operation. Variables to consider include system loads, system voltages, system outages and configurations, and **Power Generating Module** operating conditions.

The system disturbances for which stability should be maintained should be selected on the basis that they have a reasonably high probability of occurrence. It is recommended that these include short-circuit faults on single **Distribution Network** circuits (such as transformers, overhead lines and cables) and busbars, that are quickly cleared by main protection.

With the **System** in its normal operating state, it is desirable that all **Power**

Generation Modules remain connected and stable for any of the following credible fault outages,

(a) any one single circuit overhead line, transformer feeder or cable circuit, independent of length,

(b) any one transformer or reactor,

(c) any single section of busbar at or nearest the point of connection where busbar protection with a total clearance time of less than 200ms is installed,

(d) if demand is to be secured under a second circuit outage as required by ER P2/6, fault outages (a) or (b), overlapping with any pre-existing first circuit outage, usually for maintenance purposes. In this case the combination of circuit outages considered should be that causing the most onerous conditions for **System Stability**, taking account of the slowest combination of main protection, circuit breaker operating times and strength of the connections to the system remaining after the faulty circuit or circuits have been disconnected

It should be noted that it is impractical and uneconomical to design for stability in all circumstances. This may include double circuit fault outages and faults that are cleared by slow protection. **Power Generating Module**s that become unstable following system disturbances should be disconnected as soon as possible.

9. 13.7 Any **Generation Set** that causes the **System** to become unstable under fault conditions must be rapidly disconnected to reduce the risk of **Plant** damage and disturbance to the **System**.

9. 13.8 Various measures may be used, where reasonably practicable, to prevent or mitigate system instability. These may include **Distribution Network** and **Power Generating Module** solutions, such as:

- improved fault clearance times by means of faster protection;
- improved performance of **Power Generating Module** control systems (excitation and governor/prime mover control systems; **Power System Stabilisers** to improve damping);
- improved system voltage support (provision from either **Power Generating Module** or **Distribution Network** plant);
- reduced plant reactance's (if possible);
- Protection to identify pole-slipping;
- increased fault level infeed from the **Distribution Network** at the **Connection Point**.

In determining mitigation measures which are reasonably practicable, due consideration should be given to the cost of implementing the measures and the benefits to the **Distribution Network** and **Customers** in terms of reduced risk of system instability.

9.14 Island Mode

9. 14.1 A fault or planned outage, which results in the disconnection of a **Power Generating Module**, together with an associated section of **Distribution Network**, from the remainder of the **Total System**, creates the potential for island mode operation. It will be necessary for the **DNO** to decide, dependent on local network conditions, if it is desirable for the **Users** to continue to generate onto the islanded **DNO's Distribution Network**. The key potential advantage of operating in Island Mode is to maintain continuity of supply to the portion of the **Distribution Network** containing the **Power Generating Module**. The principles discussed in this section generally also apply where **Generation Plant** on a **Customer**'s site is designed to maintain supplies to that site in the event of a failure of the **DNO** supply.

9. 14.2 When considering whether **Power Generating Modules** can be permitted to operate in island mode, detailed studies need to be undertaken to ensure that the islanded system will remain stable and comply with all statutory obligations and relevant planning standards when separated from the remainder of the **Total System**. Before operation in island mode can be allowed, a contractual agreement between the **DNO** and **Power Generating Facility Owner** must be in place and the legal liabilities associated with such operation must be carefully considered by the **DNO** and the **Power Generating Facility Owner**. Consideration should be given to the following areas:

(e) load flows, voltage regulation, frequency regulation, voltage unbalance, voltage flicker and harmonic voltage distortion;

(f) earthing arrangements;

(g) short circuit currents and the adequacy of protection arrangements;

(h) **System Stability**;

(i) resynchronisation to the **Total System**;

(j) safety of personnel.

9. 14.3 Suitable equipment will need to be installed to detect that an island situation has occurred and an intertripping scheme is preferred to provide absolute discrimination at the time of the event. Confirmation that a section of **Distribution Network** is operating in island mode, and has been disconnected from the **Total System**, will need to be transmitted to the **Power Generating Module(s)** protection and control schemes.

9. 14.4 The **ESQCR** requires that supplies to **Customers** are maintained within statutory limits at all times ie when they are supplied normally and when operating in island mode. Detailed system studies including the capability of the **Power Generating Module** and its control / protections systems will be required to determine the capability of the **Power Generating Module** to meet these requirements immediately as the island is created and for the duration of the island mode operation.

9. 14.5 The ESQCR also require that **Distribution Networks** are earthed at all times. **Power Generating Facility Owner**s, who are not permitted to operate their installations and plant with an earthed star-point when in parallel with the **Distribution Network**, must provide an earthing transformer or switched star-point earth for the purpose of maintaining an earth on the system when islanding occurs. The design of the earthing system that will exist during island mode operation should be carefully considered to ensure statutory obligations are met and that safety of the **Distribution Network** to all users is maintained. Further details are provided in Section 8.

9. 14.6 Detailed consideration must be given to ensure that protection arrangements are adequate to satisfactorily clear the full range of potential faults within the islanded system taking into account the reduced fault currents and potential longer clearance times that are likely to be associated with an islanded system.

9. 14.7 Switchgear shall be rated to withstand the voltages which may exist across open contacts under islanded conditions. The **DNO** may require interlocking and isolation of its circuit breaker(s) to prevent out of phase voltages occurring across the open contacts of its switchgear. Intertripping or interlocking should be agreed between the **DNO** and the **Power Generating Facility Owner** where appropriate.

9. 14.8 It will generally not be permissible to interrupt supplies to **DNO Customers** for the purposes of resynchronisation. The design of the islanded system must ensure that synchronising facilities are provided at the point of isolation between the islanded network and the **DNO** supply. Specific arrangements for this should be agreed and recorded in the **Connection Agreement** with the **DNO**. If no facilities exist for the subsequent resynchronisation with the rest of the **DNO's Distribution Network** then the **User** will under **DNO instruction**, ensure that the **Power Generating Module** is disconnected for re-synchronisation.

9.16 Technical Requirements for Type C Power Generating Modules

Where a **Power Generating Facility Owner** in respect of a **Power Generating Module** connected to the DNO network is a party to the **CUSC** this section 9.16 will not apply.

9.15 **Black Start Capability**

The **National Electricity Transmission System** will be equipped with **Black Start Stations** (in accordance with the **Distribution Operating Code** DOC 9). It will be necessary for each User to notify the DNO if its **Power Generating Module** has a restart capability without connection to an external power supply, unless the **User** shall have previously notified the **TSO** accordingly under the **Grid Code**. Such generation may be registered by the **TSO** as a **Black Start Station**.

9.16.1.1 In addition to the requirements in this document, the **DNO** has an obligation under CC 3.3 of the **Grid Code** to ensure that all relevant **Grid Code** Connection Condition requirements are met by Embedded **Type CPower Generating Modules**. These requirements are summarised in ECC 3.3 of the **Grid Code**. It is incumbent on Embedded **Type C Power Generating Modules** to comply with the relevant **Grid Code** requirements listed in CC3.4 of the **Grid Code** as part of compliance with this **Distribution Code**.

9.16.1.2 Where data is required by **NETSO** from Embedded **Type C Power Generating** Modules, nothing in the **Grid Code** or **Distribution Code** precludes the **Power Generating Facility Owner** from providing the information directly to **NETSO** in accordance with **Grid Code** requirements. However, a copy of the information should always be provided in parallel to the **DNO**.

9.16.2 **Grid Code Connection Conditions Compliance**

The technical designs and parameters of the Embedded **Type C Power Generating Modules** will comply with the relevant Connection Conditions of the **Grid**. A statement to this effect, stating compliance with OC5.8 of the **Grid Code** is required to be presented to the **DNO** for onward transmission to **NETSO**, before commissioning of the **Power Station**. Note that the statement might need to be resubmitted post commissioning when assumed values etc have been confirmed.

9.16.2.1 Should the **Power Generating Facility Owner** make any material change to such designs or parameters as will have any effect on the statement of compliance referred to in 9.16.2 the **Power Generating Facility Owner** must notify the change to the **DNO**, as soon as reasonably practicable, who will in turn notify **NETSO**.

9.16.2.2 Tests to ensure **Grid Code** compliance may be specified by **NETSO** in accordance with the **Grid Code**. It is the **Power Generating Facility Owner's** responsibility to carry out these tests.

9.16.2.3 Where **the TSO** can reasonably demonstrate that for **Total System** stability issues the Embedded **Type C Power Generating** Modules should be fitted with a **Power System Stabiliser**, **NETSO** will notify the **DNO** who will then require it to be fitted for compliance with this section 9.16.2.3

GENERATOR PERFORMANCE CHART

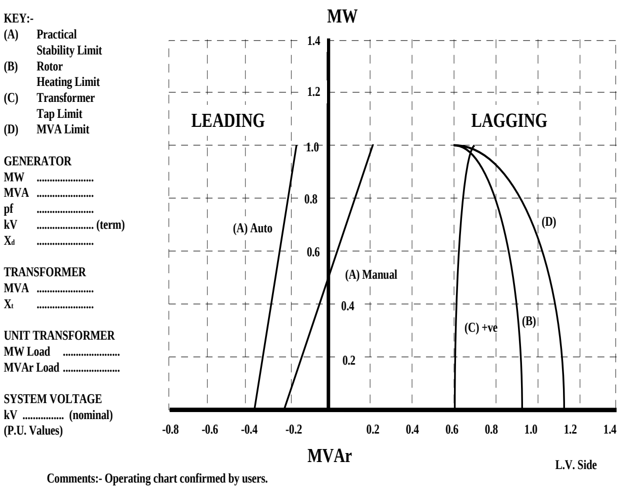

FIGURE 1

9.17 **Specification of Equipment, Overhead Lines and Underground Cables**

(a) The principles of design, manufacture, testing and installation of distribution **Equipment**, overhead lines and underground cables, including quality requirements, shall conform to applicable statutory obligations and shall comply with relevant **CENELEC** standards, **IEC** publications, European and British Standards. Further advice will be made available upon request to the **DNO**.

(b) The documents specified in paragraph (a) contain options for purchaser selection which together with other requirements that are necessary to meet **System** design needs, shall be specified so as to provide performances and ratings in line with **Electricity Supply Industry (ESI)** Technical Specifications (some of which are published as **Electricity Supply Industry (ESI)** Standards), British Electricity Board Specifications, Engineering Recommendations and Area Chief Engineers (ACE) Reports and Engineering Technical Reports and **Electricity Supply Industry (ESI)** documents as listed in Annex 1 of the **Distribution Code** or such other specifications as the **DNO** may adopt from time to time by agreement with the **Authority**.

(c) The specifications of **Equipment**, overhead lines and cables shall be such as to permit **Operation** of the **DNO's Distribution Network** within the **Safety Management System** of the **DNO**, details of which will be made available by the **DNO** upon request.

(d) **Equipment** shall be suitable for use at the operating **Frequency**, within the intended operating voltage range and at the design short-circuit rating of the **DNO's Distribution Network** to which it is connected having due regard to fault carrying capabilities and making and breaking duties. In appropriate circumstances, details of the **System** to which connection is to be made will be provided by the **DNO**. Guidance on the short circuit characteristics of the three phase **Low Voltage** system and associated supplies is provided in **Electricity Supply Industry** engineering publications, including Item 8 in DGD Annex 1 Engineering Recommendation P26/1, "The estimation of the maximum prospective short circuit current for three phase 415V supplies".

(e) Cables**,** overhead lines transformers and other **Equipment** shall be operated within the thermal rating conditions contained in the appropriate standards, specifications, and other relevant publications, taking into account the intended use. Such information will be made available by the **DNO** upon request.

(f) The standards, publications and specifications referred to in paragraphs (a) to (f) above are such standards, publications and specifications current at the time that the **Plant** and/or **Apparatus** was manufactured (and not commissioned) in the case of **Plant** and/or **Apparatus** on the **Total System**, or awaiting use or re-use. If any such **Plant/Apparatus** is subsequently moved to a new location or used in a different way, or for a different purpose, or is otherwise modified then such standards, publications and specifications current at the time that the **Plant** and/or **Apparatus** was manufactured (and not commissioned) will apply provided that in applying such standards, publications and specifications the **Plant** and/or **Apparatus** is reasonably fit for its intended purpose having due regard to the obligations of the **DNO** and the **User** under their respective licences.

(g) All **Equipment** at the **Ownership Boundary** shall meet the design principles contained above. Connections for entry to and exit from the **DNO's Distribution Network** shall incorporate a means of disconnection of the **User's** installation by the **DNO**.

9.18 **Communications and Telemetry Equipment**

Where required by the **DNO** in order to ensure control of the **DNO's Distribution Network,** communications between **Users** and the **DNO** shall be established in accordance with the following. **Users** shall provide and maintain those parts of the communications equipment within their location. Provision of any necessary communications requirements shall be in accordance with the **Connection Agreement** for a specific connection.

9.18.1 **Primary Speech Facility**

Users at their own cost shall provide and maintain equipment approved by the **DNO** by means of which routine and emergency communications may be established between the **User** and the **DNO**.

Connection to the **DNO's** corporate telephone network and any circuit or circuits required to connect the **Users** with the point of connections shall be provided in accordance with the **Connection Agreement.**

The facilities to be provided by the connection and the signalling and logical requirements for the interface between the **Users** equipment and the connection to the **DNO's** corporate telephone network will be specified in the **Connection Agreement.**

9.18.2 **Telemetry**

The **User** shall provide such voltage, current, frequency, **Active Power** and **Reactive Power** pulses and outputs and status points from his **System** as are considered reasonable by the **DNO** to ensure adequate **System** monitoring. The telemetry outstation in such a situation will be provided, installed and maintained by the **DNO**.

9.18.3 **Telecontrol Outstation**

If it is agreed between the parties that the **DNO** shall control the switchgear on the **User's System**, the **DNO** shall install the necessary telecontrol outstation. Notwithstanding the above, it shall be the responsibility of the **User** to provide the necessary control interface for the switchgear of the **User** which is to be controlled.

9.18.4 **Instructor Facilities**

Where required by the **DNO**, the **User** shall provide accommodation for special instructor facilities specified by **DNO** for the receipt of operational messages.

9.18.5 **Data Entry Terminals**

The **User** shall accommodate the **DNO's** data entry terminals for the purpose of information exchange.

9.18.6 **System Monitoring**

Monitoring equipment is provided on the **DNO's Distribution Network** to enable the **DNO** to monitor dynamic performance conditions. Under the requirements of the **Grid Code**, **Generation Sets** and **Power Stations** will need to provide signals for monitoring purposes. Where this monitoring equipment requires input signals from the

User's side of the **DNO/User Ownership Boundary**, the **User** shall be responsible for the provision of suitable signals in accordance with the **Connection Agreement].**