nationalgrid

Stage 01: Workgroup Consultation

Grid Code

GC0048: Requirements for Generators – GB Banding Threshold Setting

What stage is this document at?

01	Workgroup Consultation
02	Industry Consultation
03	Report to the Authority

This proposal seeks to modify the Grid Code and Distribution Code to accommodate the European Network Code – 'Requirements for Generators'.

This document contains the specific discussions of the Workgroup which formed March 2014.

Published on: **TBC**
Deadline for Comments: **TBC**

The Workgroup recommends:
To be completed

High Impact:
Generators; DNOs; SO

Medium Impact:
None identified

Low Impact:
None identified

Contents

Any Questions?

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About this document

This version of the document summarises the SO position on the Requirements for Generators banding threshold levels for Great Britain. It attempts to focus the attention of the workgroup, and the wider industry, to reach conclusion on finding the optimal position which reflects the reasonable needs of all system users. Feedback and data from other stakeholders at the GC0048 will be incorporated in a subsequent version of this report. Once the workgroup are agreed, it will then be taken forward to GCRP for their consideration for industry consultation.

Document Control

Version	Date	Author	Change Reference
1.0	03 March 2015	Richard Woodward (NGET)	Workgroup Consultation

1 Executive Summary

The European Network Code 'Requirements for Generators' (RfG) levies technical requirements on new[1] generator connections, in four incrementally onerous banding Types ('A-D'). This sets a sliding scale of proportionate generator response to support System Operators.

Each RfG Type has a designated connection voltage and installed unit capacity range (MW). For each European synchronous area, the MW thresholds need to be agreed via cost benefit analysis and industry consultation between TSOs and generators. They are then ratified by the Member State National Regulatory Authority (NRA). Once set, the levels cannot be adjusted for three years and even then, the same process of industry consultation and NRA approval needs to be followed.

The current draft thresholds proposed by the European Commission (see Fig. 2) by default form the ceiling up to which future MW level changes can be made. Therefore subsequent adjustments can only be within this range. In the first instance, such a change will be downwards by default (i.e. more onerous).

The January 2015 draft of RfG aligned the banding thresholds for the Great Britain (GB) synchronous area to that of Continental Europe (CE). Previous versions of the code had the banding thresholds much lower, aligning closer with the Large determination in the SHET TO region in Scotland.

Fig.1 RfG code drafting for GB thresholds (January 2014 old draft):

	Type A	Type B	Type C	Type D
Connection Voltage	<110kV	<110kV	<110kV	>110kV
Unit Capacity	0.8KW-1MW	1MW-10MW	10-30MW	30MW+

Fig.2 RfG code drafting for GB thresholds (January 2015 current draft):

	Type A	Type B	Type C	Type D
Connection Voltage	<110kV	<110kV	<110kV	>110kV
Unit Capacity	0.8KW-1MW	1MW-50MW	50-75MW	75MW+

Whilst the code draft position forms the **highest possible levels** for the GB area, an industry consultation setting out sufficient justification is still required for the NRA to ratify them (see RfG Article 5). The intention therefore is that the final levels could sit somewhere below, providing sufficient a cost-benefit case can be agreed by industry.

The System Operator (SO), National Grid Energy Transmission (NGET), has therefore presented a proposal to adjust downwards the 'ceiling' draft levels. This is to address unintended negative consequences of having higher thresholds in GB. This particularly focuses on mitigating longer term system instability, and the increasing scarcity of available and economic reserves of balancing services.

Where can I find more information on Requirements for Generators?

Content presented and discussed at the joint Grid Code and Distribution Code working group can be found at: http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/Modifications/GC0048/

[1] *Existing* generators are those connected when RfG enters into force, or those not connected but have a binding contract (which can be evidenced) to procure major plant items within two years of code entry into force. See RfG Article 4 for more information.

As part of the national implementation of RfG, the SO has raised an alternative banding proposal which it believes better reflects the longer-term demands on the system:

Fig.3 SO proposal of generator banding thresholds:

	Type A	Type B	Type C	Type D
Connection Voltage	<110kV	<110kV	<110kV	>110kV
Module Capacity	0.8KW-1MW	1MW-30MW	30-50MW	50MW+

The remainder of the document outlines the SO justification for this alternate banding threshold proposal. It discusses the accepted trends of future generation technologies, the increased risk of system instability, and the estimated costs in mitigating this.

The paper will also outline how the SO believes the RfG banding thresholds could positively support system management through broader active response from generators.

This paper will then form the basis of a workgroup consultation for stakeholder feedback will be sought. This will help define an industry consultation by which consensus on the GB banding thresholds can be achieved before the NRA is asked to make a ruling.

2 Background on RfG and the European Network Codes

In 2009, three regulations and two directives (the “**Third Energy Package**”) came into force to liberalise gas and energy markets in Europe.

Regulation (EC) No 714/2009 set a requirement to form a European Network of Transmission System Operators for Electricity (ENTSO-E), which brought together the disparate interests of the 41 European TSOs.

The regulation also stipulated the outputs of ENTSO-E, which included the formation of European Network Codes to harmonise connection, balancing and market operations functions. The overall objective of these codes are:

- Promote a more interconnected EU
- Improve system security
- Better integrate renewable technologies
- Increase competition to benefit end-consumers

Ten network codes evolved, with 'Requirements for Generators' (RfG) sitting within the ‘connection’ codes package. RfG sets technical requirements for new generation connections to distribution and transmission systems. RfG will therefore greatly impact generators large and small, as well as system owners/operators.

For the most part, the parties most greatly affected by these requirements are the Smaller Generators (50MW or below) who have traditionally been caught my a more limited set of requirements. Notwithstanding this there will changes for both Transmission and Distribution System Operators both in terms of the interaction between them and the method in which they instruct Embedded Generation.

More information on the background to ENTSO-E and European Network Codes is available in this presentation: [ENTSO-E presentation - Introduction to Network Codes]

1. Summary of workgroup progress to date

A workgroup to consider the GB implementation of RfG meetings was formed in late 2013. Its meetings are held jointly under the umbrellas of Grid Code and Distribution Code governance. These commenced in January 2014 with an open invite to all industry parties.

As well as the Distribution Network Operators (DNO) and the System Operator (SO) NGET, large-medium scale generator developers and trade associations are also in attendance. The regulator Ofgem and representatives for the Department of Energy and Climate Change (DECC) are also present.

Discussions towards agreeing the generator banding thresholds levels for GB via cost-benefit analysis have stepped up since winter 2014. This is due to the code drafting slowly reaching a conclusion.

Broad consensus at workgroup level has not yet been achieved, though representatives have not yet been required to lodge a preferred opinion. Since November, the SO has attempted to explain the operational rationale for GB adopting its banding levels proposal (Fig.3).

To date, the SO has been the only workgroup member to attempt to evidence a stance on the level of the banding thresholds. Justification for any alternate position (e.g. the levels in Fig.2) has not been submitted to the workgroup to consider.

To do this, supporting data will need to be presented (e.g. a cost-benefit analysis), which will then be considered within a comprehensive workgroup consultation for GB as a whole. This will form the basis of a case to present to industry and eventually the NRA for approval.

It is expected that RfG will be adopted by EU member states during summer 2015, through voting at the cross-border committee meetings of the European Commission. Thereafter it will go through the process of being approved by the European Parliament before being published in the European Journal. At this point (expected to be in Q4 2015), it will enter into force as European Law.

Timeline

Workgroup Meeting Dates:

1 28/01/14
2 24/03/14
3 24/09/14
4 20/10/14
5 20/11/14
6 17/12/14
7 20/01/15
8 17/02/15
9 19/03/15
10 21/04/15
11 19/05/15
12 16/06/15
13 20/07/15

The current drafting of the code then requires member states to be able to demonstrate compliance after two years. To allow for adequate lead-time in adjusting equipment specification, it is proposed that national implementation should take place as quickly as possible; current GB plans set twelve months for this.

Given the rapid timescales involved, it is critical that any pre-work that can be achieved prior to this is done. Unfortunately the biggest obstacle to efficiently progressing RfG implementation in GB is unquestionably agreeing the banding thresholds. Without agreement on this, finalising the other provisions of the code will be impossible.

This paper, along with recent presentations made to the GC0048 workgroup, attempts to encourage representatives to move towards agreeing the GB banding levels in a timely manner. This will ensure the best opportunity for overall GB compliance to be achieved.

Other outputs of the workgroup to date

- An NGET proposal for future national parameters required through RfG
- A project plan for implementation of RfG in GB
- A workgroup risks register – cataloguing areas of concern requiring mitigation by GB stakeholders before/during code entry into force
- A proposal for Grid Code modification packages for setting RfG parameters and adjusted applicable legal text

3 SO banding proposal

The SO's banding threshold proposal was written considering four objectives:

1. Alignment with any similar generator compliance categorisations currently used in GB which are currently acceptable;
2. Ensure that generators ostensibly capable of supporting system operation are categorised in an appropriate banding;
3. Highlight the significant concern and predicted cost increases that future generation trends pose the SO in managing the system
4. Avoid placing unduly onerous costs of compliance on smaller generators

…and that the overall approach avoids unintended negative consequences.

1. Alignment with existing generator designations used in GB codes

The Grid Code currently groups generators to apply appropriate technical and commercial obligations. These have three tiers (Small, Medium and Large) and have regional variants depending on the host Transmission area (north or south Scotland; England and Wales).

For the determination of generator class under the Grid Code, the host Transmission Owner takes priority following by installed MW capacity. The voltage at the point of connection is not of explicit importance. Instead it is the nature and location of the connection which drives the resulting compliance requirements, i.e. whether the generator connects to distribution or transmission system equipment.

Fig.4 Grid Code Generator categories:

Generator Size	Direct Connection to:		
	SHET	SPT	NGET
Small	<10MW	<30MW	<50MW
Medium			50-100MW
Large	10MW+	30MW+	100MW+

Comitology

What is Comitology?
http://ec.europa.eu/transparency/regcomitology/index.cfm?do=implementing.home

Under RfG, four Type bands will set the technical requirements, which need to be adopted into the appropriate GB connection code. Types A and B set requirements which largely approximate to a manufacturer standard, and so are expected to be a passive operational responsibility.

More responsive engagement with the System Operator, along with broader stability requirements, is required in Type C-D.

Unlike the Grid Code equivalent generator levels, RfG explicitly states the connection voltage then with the installed capacity range. This means that any generator connection to voltages greater than 110kV[2] (the nearest approximate equivalent in GB is 132kV) will automatically be designated in the most onerous banding of D. For 110kV or less, the capacity will take priority for determining Type:

Fig.2 RfG code drafting for GB thresholds (January 2015 current draft):

	Type A	Type B	Type C	Type D
Connection Voltage	<110kV	<110kV	<110kV	>110kV
Unit Capacity	0.8KW-1MW	1MW-50MW	50-75MW	75MW+

Fig.3 SO proposal for generator banding thresholds:

	Type A	Type B	Type C	Type D
Connection Voltage	<110kV	<110kV	<110kV	>110kV
Module Capacity	0.8KW-1MW	1MW-30MW	30-50MW	50MW+

In regards to the methodology for the Types, it is a reasonable approximation to have Type C requirements upwards as representing the existing Large designation of generators in GB under Grid Code. This is primarily because Type C stipulates real-time monitoring and Frequency Response provisions. Type D applies no additional technical requirements; it instead sets the maximum capability for operational parameters.

Immediately noticeable in comparing the January 2015 draft banding levels for GB to Grid Code is the disparity to the existing Scottish regional designations, in both TO regions. The MW capacities for a ‘Large’ generator (to whom the most onerous Grid Code requirements are associated) are set at 10MW and 30MW respectively, purposefully lower than that of England and Wales (50MW).

[2] 110kV used as a thresholds as it is a common European distribution voltage

In fact previous iterations of the RfG draft bandings (Fig.1) reflected the lowest GB levels quoted in the Grid Code (10MW), but this was subsequently revised to be consistent with levels proposed for Continental Europe.

Fig.1 RfG code drafting for GB thresholds (January 2014 old draft):

	Type A	Type B	Type C	Type D
Connection Voltage	<110kV	<110kV	<110kV	>110kV
Unit Capacity	0.8KW-1MW	1MW-10MW	10-30MW	30MW+

There has been lengthy workgroup discussion on the Type C level; the category where Frequency Response obligation is set from. In relation to how the proposed banding levels fit with existing Grid Code requirements, section CC 6.3.7(e) sets this for:

(i) Each **Onshore Generating Unit** and/or **CCGT Module** which has a **Completion Date** after 1 January 2001 in England and Wales, and after 1 April 2005 in Scotland, must be capable of meeting the minimum **Frequency** response requirement profile subject to and in accordance with the provisions of Appendix 3.
(ii) Each **DC Converter** at a **DC Converter Station** which has a **Completion Date** on or after 1 April 2005 and each **Offshore DC Converter** at a **Large Power Station** must be capable of meeting the minimum **Frequency** response requirement profile subject to and in accordance with the provisions of Appendix 3.
(iii) Each **Onshore Power Park Module** in operation in England and Wales with a **Completion Date** on or after 1 January 2006 must be capable of meeting the minimum **Frequency** response requirement profile subject to and in accordance with the provisions of Appendix 3.
(iv) Each **Onshore Power Park Module** in operation on or after 1 January 2006 in Scotland (with a **Completion Date** on or after 1 April 2005 and a **Registered Capacity** of 50MW or more) must be capable of meeting the minimum **Frequency** response requirement profile subject to and in accordance with the provisions of Appendix 3.
(v) Each **Offshore Generating Unit** in a **Large Power Station** must be capable of meeting the minimum **Frequency** response requirement profile subject to and in accordance with the provisions of Appendix 3.
(vi) Each **Offshore Power Park Module** in a **Large Power Station** with a **Registered Capacity** of 50 MW or greater, must be capable of meeting the minimum **Frequency** response requirement profile subject to and in accordance with the provisions of Appendix 3.
(vii) Subject to the requirements of CC.6.3.7(e), **Offshore Generating Units** at a **Large Power Station**, **Offshore Power Park Modules** at a **Large Power Station** and **Offshore DC Converters** in a **Large Power Station** shall comply with the requirements of CC.6.3.7. **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.
(viii) Each **OTSDUW DC Converter** must be capable of providing a continuous signal indicating the real time frequency measured at the **Interface Point** to the **Offshore Grid Entry Point**.

This ambiguity increases when you consider that the ability to provide the necessary data and be instructed for mandatory Frequency Response is allied with a BSC accession requirement which can be waived via licence exemption. This means many generators in the 50-100MW (LEEMPS) bracket are required to satisfy the obligation but have no mechanism to be instructed to provide it, unless they pursue additional contractual mechanisms with National Grid.

This is an unforeseen consequence of the Grid Code drafting which RfG may not be able to remedy. However, as we will discuss in later sections of the report, placing the RfG banding thresholds to avoid a coding ambiguity would not be sensible.

Commercial frameworks and market access arrangements are not in the scope of the Grid Code/Distribution Code, nor RfG. These codes set the framework for technical competency, and should not be draft to attempt to avoid inefficiencies outside their control. This principle is discussed further when considering generator capability in the banding threshold setting.

Conclusions:

- The proposed RfG banding thresholds for larger-scale generators (Type C-D) erodes the existing levels set by the Grid Code for connections in all GB areas, not least the Scottish TO areas
  - Even the National Grid alternate proposal sets Type C higher than the lowest level currently set for the SHET TO region.
- Frequency Response capability is already mandated for units at 'Large' generating stations in the Grid Code. RfG should be no different and should not bias between technology and connection date in this regard
- The commercial framework to deliver mandatory Frequency Response capability should not be in the scope of the RfG code adoption exercise for GC0048, including banding threshold setting.

Next Steps:

- Generators support the cost-benefit analysis needed for full workgroup consultation (for presentation in April)

2. Ensuring proportionate generator response

A large contribution to the lengthy workgroup debate on banding thresholds is determining reasonable operator-to-generator response levels. There is particular concern on the increasing segment of non-synchronous renewable plant, and where their obligations should fall.

Due to the current GB drafting of the thresholds, these units would either fall in Type B (largely passive obligations) or Type C (responsive and more onerous).

Generators naturally would like to avoid these arduous requirements, as they generally carry a greater cost to comply with. However the SO would prefer generators capable of supporting system operation to do so, and feel setting a codified obligation to steer new equipment manufacturer specifications is the best means to do this.

The real-time granularity of generator requirements within Type C and D (e.g. monitoring and controlling of output) are a key concern for generator costs. However inevitably re-categorising units from Type B to Type C to avoid this shifts an operational burden (and cost) from the generators to the SO.

This debate however neglects the fact that a large proportion of the technical compliance requirements for plant, particularly wind, are existing manufacturing standards. In other words most equipment for generators determined to be in the Type B-D range would already confirm to RfG compliance levels.

Investment drivers for generators will dictate whether they procure/activate the necessary capability to respond to SO requests, especially if this is not a code obligation. While participation in ancillary service markets such as Frequency Response provide an alternate revenue stream, if a capability is not mandated and it costs more, why would a generator procure it?

A primary example of this is the capability to safely de-regulate or cap output for Balancing/Frequency Response for wind generators. Most Wind Turbine Generator (WTG) manufacturers configure the hardware for this capability when the turbine capacity reaches levels where 'larger' scale plant operation can be assumed. This does not preclude mid-level capacity WTGs (e.g. 2MW) being deployed in power park modules falling anywhere within Types B-D however.

Most multi-national manufacturers will build for the most onerous requirements in the regions they sell – meaning the most stringent obligation capability is accounted for. It is a moot point whether this is GB or elsewhere under RfG:

Fig.5 – January 2015 draft thresholds for other EU synchronous areas

Synchronous Area	Type B (<110kV)	Type C (<110kV)	Type D (>110kV)
Continental Europe	1 MW	50 MW	75 MW
Nordic	1.5 MW	10 MW	30 MW
Ireland	0.1 MW	5 MW	10 MW
Baltic	0.5 MW	10 MW	15 MW

The average WTG capacity for **operational** projects between 10MW-100MW is 2.2MW in England; 1.99MW in Scotland; and 1.7MW in Wales. Approximating therefore to a round 2MW, where basic products are considered to be inherently Grid Code compliant (according to manufacturers[3]), existing operational wind project capacities[4] where 2MW or greater WTGs are deployed are: 37.9MW in England; 33.5MW in Scotland; and 23.5MW in Wales.

Each of these falls well within the National Grid RfG banding proposal. However under the existing GB draft, plants with the inherent capability and capacity could be designated as Type B, where no active grid support obligations are set. This concerns the SO, and therefore generators should be encouraged to disclose whether there are any incremental costs for equipment to be compliant, before commercial participation costs are considered.

[3] http://www.energy.siemens.com/hq/en/renewable-energy/wind-power/platforms/g2-platform/wind-turbine-swt-2-3-93.htm; http://windpowerpioneers.vestas.com/capabilities/wind-project-planning/grid-integration
http://www.gepowerconversion.com/industries/renewables/wind-solutions
[4] Renewable UK UKWED Database - http://www.renewableuk.com/en/renewable-energy/wind-energy/uk-wind-energy-database/index.cfm

Conclusions:

- SO is concerned about reserves for response and reserve ancillary services
- RfG banding thresholds should reflect generator capability as well as the needs of SOs. Market arrangements (whilst important) are out of scope.
- Compliance of generator equipment built to a certain scale is likely to be inherent in the manufacturer's build standards
- It would not be unreasonable to assume that incremental costs for generator equipment of a 'reasonable' scale (capacity) to be RfG compliant, would be negligible to minimal. However the choice of which hardware generators purchase is driven by additional commercial factors.
- Implicit potential for existing generators to provide more support if they were motivated

Next Steps:

- Generator perspectives, reinforced with quantitive data for use in a workgroup consultation cost-benefit analysis.

SO management of future generation trends

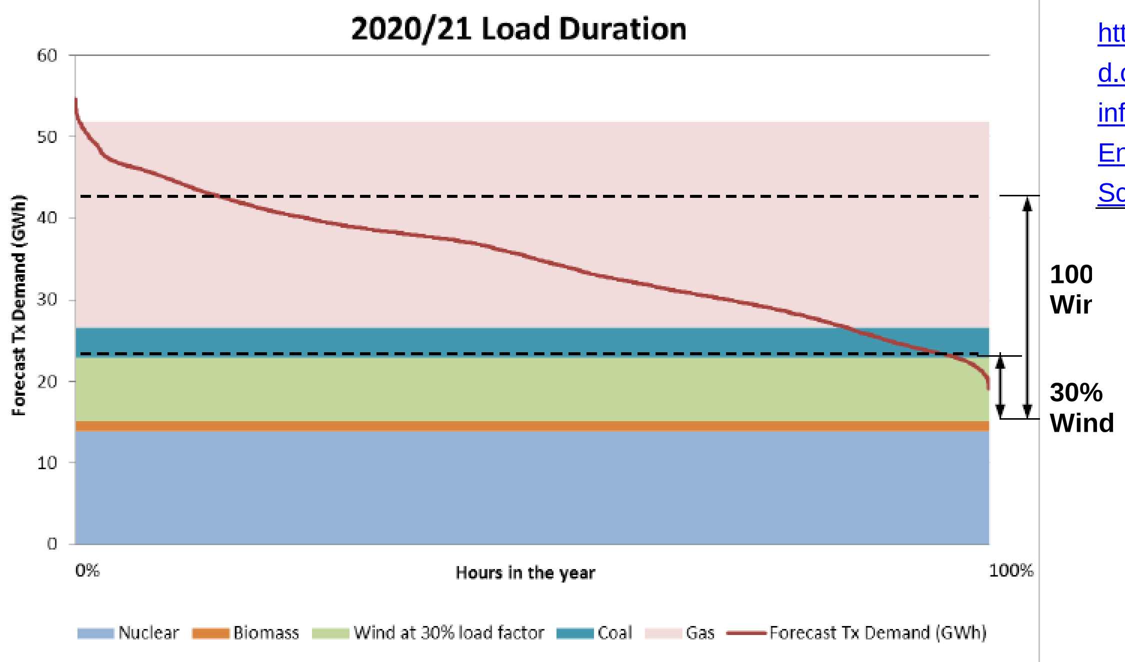
The key trends which the SO forecasts to negatively impact System operation in future years are increasing volumes of intermittent generation; and that a large portion of that is embedded on the distribution network. This means it is not commercially (or operationally) visible to the SO. These issues are discussed in greater detail, including contextual analysis, in the Future Energy Scenarios (FES).

FES

This annual publication describes NGET's analysis of credible future energy scenarios out to 2035 and 2050.

http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Future-Energy-Scenarios/

Fig 5. Projection of generator types (FES Slow Progression scenario)



In isolation, the increase in renewable generation sources on the system as part of a broad mix including an increasing thermal synchronous plant portfolio would not be an issue. However due to increasingly demanding emissions quotas and adverse commercial conditions, older Large plant will be decommissioned or mothballed during the next decade.

This decreases the amount of flexible generation on the system capable of providing full response capabilities, or to ensure minimum demand is satisfied when intermittent generation isn't able to provide output.

The GC0048 workgroup collected data to profile generation connections over the coming decade. This was mapped against each of the RfG banding proposals to project the likely volume of generation for each Type.

Fig.5 – GB draft of RfG band thresholds and predicted project volumes

GB (Jan '15)	Type A: 0.8kW-1MW		Type B: 1-49.9MW	
	Projects	MW	Projects	MW
DNO TOTAL	2,287,025	22,182.403	3,842	6,793.285
TEC Reg			51	1,577.450
Embedded Reg			87	646.360
TOTAL	**2,287,025**	**22,182.403**	**3,980**	**9,017.095**

GB (Jan '15)	Type C: 50-74.9MW		Type D: 75MW+	
	Projects	MW	Projects	MW
DNO TOTAL	0	0.000	14	750
TEC Reg	0	0.000	138	80,482
Embedded Reg	0	0.000	1	65
TOTAL	**0**	**0.000**	**153**	**81,297.300**

Fig.6 – NGET proposed RfG band thresholds and predicted project volumes

GB (NGET Proposal)	Type A: 0.8kW-1MW		Type B: 1-29.9MW	
	Projects	MW	Projects	MW
DNO TOTAL	2,287,025	22,182.403	3,842	6,793.285
TEC Reg			24	511.850
Embedded Reg			85	580.260
TOTAL	**2,287,025**	**22,182.403**	**3,951**	**7,885.395**

GB (NGET Proposal)	Type C: 30-49.9MW		Type D: 50MW+	
	Projects	MW	Projects	MW
DNO TOTAL	0	0.000	14	750
TEC Reg	27	1,065.600	138	80,482
Embedded Reg	2	66.100	1	65
TOTAL	**29**	**1,131.700**	**153**	**81,297.300**

Full presentation: http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=39433

Immediately noticeable is the significant volumes (22.2GW) predicted for Type A. As the banding threshold for this category of generator is not being debated in GB (so is the same under both banding proposals), this will be a volume position to reiterate which has no support obligations, or visibility, to the SO.

It is important to note that 92% of the Type A position represents Solar PV technology, containing a large proportion of domestic installations. This will be important for managing Type A unit compliance, but most important predicts a significant capacity trend which will need to be managed.

When factored with an additional 6.7GW in Type B capacity, where 74% constitutes onshore wind projects, suddenly a considerable block of primarily intermittent uncontrollable generation requires balancing and management by the SO. The reality is, with older thermal plant being decommissioned, there is a displacement effect from synchronous response plant, to non-synchronous embedded plant.

In regards to the project/capacities under the differing banding proposals for Types C-D, both proposals have the same amount of Type D generation due to schemes exceeding the higher capacity threshold, or they have a 132kV connection or greater. In regards to Type C however, the GB draft bandings forecast *no* Type C schemes, due to the higher threshold. Under the NGET proposal, there is a moderate position of residual Type C generation.

Regardless of the merits of either proposal, there should be concern over the lack of Type C. This is an issue firstly for generators avoid the most far-reaching requirements by being designated Type B. But on the other hand, generators with 132kV-connections are Type D by default; so capacity is not considered. Consequentially generators who could easily be considered Type C, or even B (GB draft band = 1MW – 49.9MW) would end up providing the most onerous requirements anyway.

Costs to the SO

NGET is the sole party in GB responsible for controlling system frequency. When there are constraints or issues with intermittency, the SO calls upon commercially viable responsive generation to support through mandatory and commercial ancillary services.

In general, the SO prefers traditional thermal plant for Frequency Response, as they are more flexible, predictable, and can price competitively. As this type of generation exits the system due to political and environmental reasons, the SO will be forced to rely on non-synchronous plant to play its part adding more criticality to agreeing a reasonable Type C band threshold.

The alternative in absence of more providers is to pursue more expensive options for managing system stability. This includes dispatching plant out of merit order and/or increasing reserve carrying requirements.

A constant 1GW of reserve held traditionally to cover Normal Infeed Loss Risk (infrequent infeed loss increased to 1.8GW from 1 April 2014). This was determined by the need to keep frequency within operational limits and this continues to be the case.

Reserve is expressed as a % of total generation, with 2% reserves held under peak conditions and rising volumes, increasing to about 4% at minimum. Depending on which banding thresholds are selected, generation shifts from Types C/D to Type B, and is no longer available for this.

In order to quantify the costs of procuring additional reserves needed where plant avoid being categorised into a higher RfG Type, the SO used existing prices in the context of the slow progression load model put forward in the FES. It weighed up the need to procure more synchronous plant (typical Combined Cycle Gas Turbine plant) over intermittent wind plant. A worked example is provided as an appendix.

A lot of the concern in the workgroup is that the SO has abundant resources at the moment and that if unchecked, surplus capacity for reserve and response will accumulate which may/may not been accessible to be dispatched resulting in the risk of stranded assets.

The overriding principle remains however, that technical capability and commercial capability are not the same thing. This is a combination of generator commercial inclination, or that the path to market is not accessible. However, as already discussed, the connection codes do not prescribe the arrangements by which generators discharge their obligation.

Anticipated costs to Generators

For operators of newer generators technologies, particularly wind, commercial behaviours are drastically different to traditional thermal plant. Subsidy regimes are in place to incentivise renewable technology investment (over and above sale of power output), and the greatest reward to applicable generators is if they can generate as many MWhs as possible. This principle promotes contradictory behaviour to being able to support the SO in providing Ancillary Services (e.g. output deregulation or capping).

This drives commercial behaviours for Large plant pricing into balancing service participation. The subsidy is typically the greatest element when prices are cost-reflective (e.g. not sleeper bids or exorbitant pricing now prohibited under the Transmission Constraint Licence Condition).

The level of subsidy typically raises these providers outside competitive/economic options for SO to dispatch, and make them typically a last resort option. When constraints give limited choice to the SO, an increased cost is incurred for calling these providers. This pattern will only continue as these system stability issues persist.

It is important to note that the opportunity cost for renewable plant pricing in for balancing services under the Renewables Obligation (RO) or the new Contracts for Difference (CfD) regimes will largely be the same. Under CfD (which will largely be the subsidy route of choice for generators post-RfG) the price of lost revenue will be from a power price top-up. As this top-up is based largely on the current RO buyout, prices for new renewable providers for ancillary services will inevitably stay the same as current levels.

In regards to the ability for intermittent generators to accurately provide forecast data for the SO, recent Grid Code developments should assist with this deficiency. A mandatory power available signal for new intermittent wind units from 2016 onwards will give the SO direct visibility of potential headroom for response provisions. This will allow generators to be instructed to cap output to provide upwards response rather than simply be an option for downward regulation, dependant on if their pricing for this is economically viable.

Removing barriers to entry for ancillary services markets allows the debate on RfG band thresholds to focus on what is reasonable to expect from generators. NGET is working on several initiatives to improve the access to Frequency Response and Reserve bilateral markets, particularly for smaller generator entities. But as already discussed, the market facilitation is not for discussion.

Conclusions

- Increases in intermittent generation on the system, most of which will be embedded, creates an incremental system balancing burden for the SO to manage
- Categorising scalable generation as Type C reduces this burden by contributing response requirements
- Categorising scalable generation within a broad Type B ('passive') RfG band exacerbates the problem of 22GW of Type A generation which will be 'invisible' to the SO.
- High probability that reserve and out of merit costs increase within years of RfG entering into force; banding thresholds can either assist with this, or exacerbate the situation by 'unburdening' capable generators
- Commercial frameworks and market enablers (out of scope of RfG) need to better encourage generators to participate. However the obligation should be in place regardless. Traditional contractual methods coupled with new ways of discharging obligations could be viable for smaller players (i.e. third party Control/Trading Points)

Next steps

- Generator perspectives, reinforced with quantitive data for use in a workgroup consultation cost-benefit analysis.

4 Retrospective Application to existing generators

The SO does not anticipate using the provisions (RfG Article 4) for retrospective application to existing generators during RfG code implementation. Therefore the proposed generator banding thresholds would apply to only new connections from entry into force, excluding those able to declare and evidence 'existing' status.

However, if circumstances for the SO deteriorate after the code enters into force, possibly due to unforeseen consequences from the banding threshold setting, this stance may be revisited if acceptable to the GB national regulatory authority (Article 4 – Clause 3).

5 Next steps

This paper will be presented at the March GC0048 workgroup meeting. It will be circulated for comment in attempt to agree final positions in April. The workgroup are also encouraged to present alternative cost-benefit analysis to justify the existing draft band levels, which should also be presented in April. We will then attempt to reach consensus on where the banding thresholds should be to take to industry consultation.

Indicative Timeline

Date	**Activity**
Thurs 12 Mar	Circulate this paper to the GC0048 workgroup
Thurs 19 Mar	Present high level concepts to workgroup review any comments
Tues 21 Apr	Present final view of paper; review any GC0048 cost benefit analysis for draft RfG banding position
Wed 6 May	Redraft paper as Workgroup Consultation; submit to GCRP
Wed 20 May	Present Workgroup Consultation to GCRP for consideration – seek approval to consult with industry on the proposal banding levels
Mon 1 June	Draft Industry Consultation paper and commence industry consultation (20 WKDs)
Fri 26 June	Consultation concludes
Fri 3rd July	Redraft paper to incorporate industry responses
Fri 10th July	Draft industry paper and submit to NRA
Mon 20th July	Present industry consultation responses to GC0048. IF acceptable, prepare report to authority
Monday 3rd August	Submit report to authority to Ofgem
Friday 4th September [or soon after code enters into force]	Authority decision

Appendix 1 – Worked example for SO costs for procuring reserve

Grain out of merit running - 01/12/12
Grain unit was run overnight to provide reserves, at an actual additional cost of £120k. Assuming 10 hours running with standard part-loading leaving about 200MW possible reserve during this period the cost (per MWh of reserve) = £60

How much reserve is required?

Fig.5 – GB draft of RfG band thresholds and predicted project volumes

GB (Jan '15)	Type A: 0.8kW-1MW		Type B: 1-49.9MW	
	Projects	MW	Projects	MW
DNO TOTAL	2,287,025	22,182.403	3,842	6,793.285
TEC Reg			51	1,577.450
Embedded Reg			87	646.360
TOTAL	**2,287,025**	**22,182.403**	**3,980**	**9,017.095**

GB (Jan '15)	Type C: 50-74.9MW		Type D: 75MW+	
	Projects	MW	Projects	MW
DNO TOTAL	0	0.000	14	750
TEC Reg	0	0.000	138	80,482
Embedded Reg	0	0.000	1	65
TOTAL	**0**	**0.000**	**153**	**81,297.300**

Fig.6 – NGET proposed RfG band thresholds and predicted project volumes

GB (NGET Proposal)	Type A: 0.8kW-1MW		Type B: 1-29.9MW	
	Projects	MW	Projects	MW
DNO TOTAL	2,287,025	22,182.403	3,842	6,793.285
TEC Reg			24	511.850
Embedded Reg			85	580.260
TOTAL	**2,287,025**	**22,182.403**	**3,951**	**7,885.395**

GB (NGET Proposal)	Type C: 30-49.9MW		Type D: 50MW+	
	Projects	MW	Projects	MW
DNO TOTAL	0	0.000	14	750
TEC Reg	27	1,065.600	138	80,482
Embedded Reg	2	66.100	1	65
TOTAL	**29**	**1,131.700**	**153**	**81,297.300**

Comparing January 2015 RfG draft to NGET proposal, there is a 1.1 GW swing from Type C to Type B. If plant is not available to provide reserves (because it is now Type B) it has to be replaced from alternate sources.

Assuming a figure of 3% (between maximum and minimum demand levels of 2 and 4% respectively) of capacity to be the quantity of reserve that needs to be replaced – then a 1.1GW swing away from Type C/D to B requires **33MW** more reserve

33MW * £60/MWh * 8,568 = **£16,964,640/year**