RfG Banding Threshold Setting Considerations

GC0048 RfG Workgroup meeting 17th December 2014

(updated and extended for Workgroup meeting 20th January 2015)

Caveat

Please take this as a work in progress to stimulate discussion and highlight where further analysis needs to take place!

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RfG Banding Proposals - recap

- Requirements upon generators in RfG are grouped into bandings based on size and connection voltage
- Will need to consider how this works with current GB Small/Medium/Large classifications with type A-D bandings
- Broadly type A-B requirements are more ‘passive’ while C-D are closer to existing GB Grid Code
- TSOs need to define thresholds – but may not be above levels set out in code

Current Grid Code banding:

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

RfG banding – Jan 2014 draft:

RfG Type	Generator Capacity	Connection Voltage
A	800W-1MW	<110kV
B	1-10MW	<110kV
C	10-30MW	<110kV
D	≥30MW	>110kV

RfG Threshold Setting Process

TSOs are required to set the thresholds within the maximum bandings allowed by synchronous area. This work is required to:

a) be based on accurate data, and in this context Power Generating Facility Owners shall assist and contribute to this the determination of the threshold and provide the relevant data as requested by the Relevant TSO.

b) be coordinated with adjacent TSOs and DSOs

c) follow public consultation by the Relevant TSO

d) be subject to the approval of the National Regulatory Authority respecting the provisions of Article 4(3).

Synchronous Area	RfG Jan 2014 Thresholds			
	A	B	C	D
Continental Europe	800W-1MW	1MW-50MW	50MW-75MW	75MW+
Nordic	800W-1.5MW	1MW-10MW	10MW-30MW	30MW+
Great Britain	800W-1MW	1MW-10MW	10MW-30MW	30MW+
Ireland	800W-0.1MW	1MW-5MW	5MW-10MW	10MW+
Baltic	800W-0.5MW	1MW-10MW	10MW-15MW	15MW+
Possible GB alternative (NGET proposal)	800W-1MW	1MW-30MW	30MW-50MW	50MW+

Process to Set Banding Thresholds

Code Text – Jan 2014 draft: Article 3b

3. When TSOs define the thresholds pursuant to Paragraph 2 subparagraphs b, c and d, they shall:

4. Be based on accurate data, in this context Power Generating Facility Owners shall assist and contribute to the determination of the threshold and provide relevant data as requested by the Relevant TSO.

i. be coordinated with adjacent TSOs and DSOs

ii. follow public consultation by the Relevant TSO

iii. be subject to the approval of the National Regulatory Authority respecting the provisions of Article 4(3).

5. The Relevant TSO shall have the right to re-assess the determination of the thresholds referred to in Paragraph 2 subparagraphs b, c and d if relevant circumstances have changed materially, but not more often than every three years and respecting the provisions of Article 4(3).

What is the most important GB threshold?

Band B – Band C Threshold

- Main consideration:
  - Band B generators do not have to provide frequency response
  - Band C do
- Both band B and C are for connection at <110kV
- Starting point for GB threshold between B and C was 10MW (14 Jan 2014 draft) but could increase
- TSO can adjust thresholds down (ie making the code more onerous) if a case for this can be made
- The following analysis assumes all generators with frequency response capability can access this market

Frequency Response – GB background

Mandatory existing GB Grid Code requirement for:

- England & Wales: 50MW+

…but 50-100MW plant without a MSA can't be instructed (and also needs to accede to the BSC and have dispatch comms)

- Scotland:
  - 10MW+ SHET area
  - 30MW+ SPT area
  - 50MW+ (non-synchronous)
- Frequency response instructions are generally made through the BM (although there are some separate mutually agreed commercial arrangements)
- Generally no access to smaller providers
- RfG requires frequency response from band C which will include

Grid Code CC.A.3.1 – application of frequency response requirements

The frequency response capability is defined in terms of Primary Response, Secondary Response and High Frequency Response. This appendix defines the minimum frequency response requirement profile for:

(a) each Onshore Generating Unit and/or CCGT Module which has a Completion Date after 1 January 2001 in England and Wales and 1 April 2005 in Scotland and Offshore Generating Unit in a Large Power Station,

(b) each DC Converter at a DC Converter Station which has a Completion Date on or after 1 April 2005 or each Offshore DC Converter which is part of a Large Power Station.

(c) each Onshore Power Park Module in England and Wales with a Completion Date on or after 1 January 2006.

(d) each Onshore Power Park Module in operation in Scotland after 1 January 2006 with a Completion Date after 1 April 2005 and in Power Stations with a Registered Capacity of 50MW or more.

(e) each Offshore Power Park Module in a Large Power Station with a Registered Capacity of 50MW or more.

For the avoidance of doubt, this appendix does not apply to:

(i) Generating Units and/or CCGT Modules which have a Completion Date before 1 January 2001 in England and Wales and before 1 April 2005 in Scotland,

(ii) DC Converters at a DC Converter Station which have a Completion Date before 1 April 2005.

(iii) Power Park Modules in England and Wales with a Completion Date before 1 January 2006.

(iv) Power Park Modules in operation in Scotland before 1 January 2006.

(v) Power Park Modules in Scotland with a Completion Date before 1 April 2005.

(vi) Power Park Modules in Power Stations with a Registered Capacity less than 50MW.

(vii) Small Power Stations or individually to Power Park Units; or.

(viii) an OTSDUW DC Converter where the Interface Point Capacity is less than 50MW.

Frequency Response Issues

- Growing volume of embedded generation displacing traditional providers of frequency response (large synchronous plant)
- Growing volume of demand management
- RfG mandates frequency response from type C generators
- No clear route to market for non-BM participants/those without a MSA other than by separate commercial arrangements
- Issues will also need to be addressed in GB Grid Code Frequency Response Workgroup (GC0087)

Projection of Generation Types by 2020 (Slow Progression model)

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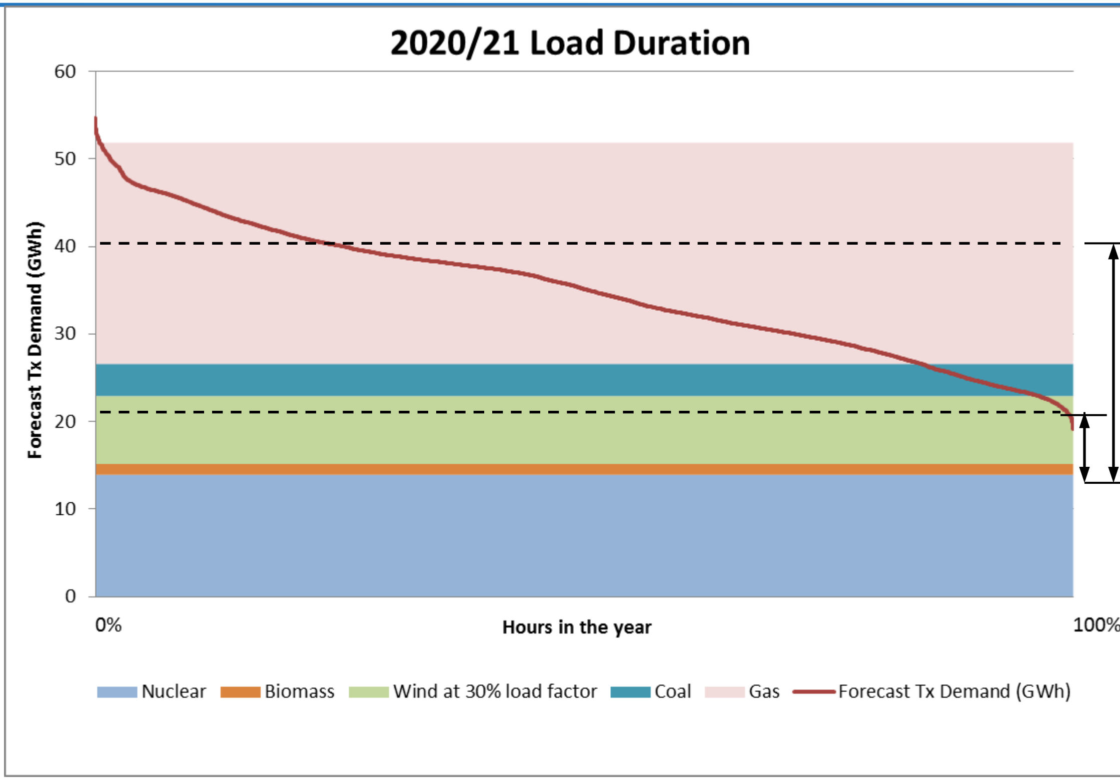

100% wind

30% wind

Key message:
As wind capacity increases it will more frequently be the marginal plant and therefore the most economic provider of balancing services

- By 2020 for significant periods of time very little conventional flexible generation may be running.
- Alternative sources of ancillary services must be secured
- Faster adoption of renewables will bring these timescales forwards

Note:

- The data for this graph is based on the 'slow progression' model from the 2014 Future Energy Scenarios document: http://www2.nationalgrid.com/uk/industry-information/future-of-energy/future-energy-scenarios/
- Load factors are assumed based on DECC's information.
- Windfarm load factor is assumed to be 30%. This may be debatable but is presented for illustrative purposes
- Demand is based on 2015 predictions - so genuine projection for 2020 may be slightly higher (or indeed lower)
- No assumptions on curtailment of generation to provide head room for reserve, downward regulation, response or inertia are included

Considerations for Setting of B-C Banding Threshold

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Balance required between:

- Costs incurred by generators in complying with more onerous banding
- Costs incurred by System Operator in allowing greater volumes of generation to connect without specific capabilities
- …and the need to consider generator compliance aspects

ie Possible configurations – so for example, a 300MW windfarm made up of 10MW sub-blocks and connected at <110kV could be type B but is more appropriately type D

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Impact on System Operation

Significant volumes of generation connecting to the system without frequency response capability *could* lead to:

- Reduced competition & hence increased prices in ancillary services market
- Reduced overall frequency response resilience
- Increased reserve carrying requirements
- Out of merit running to ensure adequate reserves/ancillary services available
- Increased operating costs

Quantifying System Operator Costs

To quantify costs to the SO need to consider:

- Cost of holding reserves
- The volume of reserves displaced by plant without frequency response that therefore needs to be procured
- NGET is the sole party in GB responsible for controlling system frequency

Costing – method #1

Place your chosen image here. The four corners must just cover the arrow tips. For covers, the three pictures should be the same size and in a straight line.

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Cost of Reserves

- Assume cost is £50/MWh (covers out of merit running or curtailment)
- Equates to an annual cost of £450k/MW (x8760 hours)

Is this a reasonable estimate?

Actual example – Grain out of merit running, 1/12/12:

- 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
- Cost (per MWh of reserve) = £60

How much reserve is required?

- Reserve carrying requirements:
  - Constant 1GW of reserve held traditionally to cover Normal Infeed Loss Risk
  - Infrequent infeed loss increased to 1800MW from 1 April 2014
  - Determined by need to keep frequency within operational limits
  - This continues to be the case – see SQSS modification GSR015 Normal Infeed Loss Risk http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/SQSS/Modifications/GSR015/
  - Expressed as a % of total generation (supplying peak demand of 50GW), 2% reserves are held rising to about 4% at minimum
- Depending on which banding thresholds are selected, generation will shift from bands C/D to band B
- Generation moving into band B will not provide frequency response & will therefore require additional/replacement reserve to be procured

Analysis of banding proposals – combined view of future generator data

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Future Schemes (2015-)

	Type A Projects	Type A MW	Type B Projects	Type B MW	Type C Projects	Type C MW	Type D Projects	Type D MW
GB (Jan 14)	**0.8KW-1MW**	**0.8KW-1MW**	**1MW-10MW**	**1MW-10MW**	**10-30MW**	**10-30MW**	**30MW+**	**30MW+**
TEC / Emb Reg	0	0.000	58	237.810	52	1,052.720	86	5,025.600
DNO	1,146,932	5,869.923	1,595	3,676.567	88	1,352.696	9	450.000
TOTAL	1,146,932	5,869.923	1,653	3,914.377	140	2,405.416	95	5,475.600
CE (Jan 14)	**0.8KW-1MW**	**0.8KW-1MW**	**1MW-50MW**	**1MW-50MW**	**50-75MW**	**50-75MW**	**75MW+**	**75MW+**
TEC / Emb Reg	0	0.000	146	2,696.230	31	1,913.600	19	1,706.300
DNO	1,146,932	5,869.923	1,683	5,029.263	9	450.000	0	0.000
TOTAL	1,146,932	5,869.923	1,829	7,725.493	40	2,363.600	19	1,706.300
GB (NGET Proposal)	**0.8KW-1MW**	**0.8KW-1MW**	**1MW-30MW**	**1MW-30MW**	**30-50MW**	**30-50MW**	**50MW+**	**50MW+**
TEC / Emb Reg	0	0.000	110	1,290.530	36	1,405.700	50	3,619.900
DNO	1,146,932	5,869.923	1,683	5,029.263	0	0.000	9	450.000
TOTAL	1,146,932	5,869.923	1,793	6,319.793	36	1,405.700	59	4,069.900

Green denotes decrease in generator capacity by comparison with Jan 2014 draft thresholds; **Red** denotes increase

- 3 views of data given here looking at what band future generator connections will sit in:
  - Jan 2014 draft (GB thresholds)
  - Jan 2014 draft (Continental Europe thresholds)
  - Median position between GB & CE bandings (NGET proposal)
- Bands C-D decrease by 3800MW with CE threshold levels, 2400MW with NGET proposed thresholds compared to the Jan 2014 draft GB threshold figures
- Band B increases by the same amounts

How much reserve is required?

- Taking Jan 2014 draft GB thresholds as base case:
  - Moving to CE thresholds causes a swing to band B of 3.8GW
  - Moving to NGET proposed levels causes a swing of 2.4GW
- Assume plant not available to provide reserves (ie because it is now band B) has to be replaced somehow
- Assume a figure of 3% of capacity to be the quantity of reserve that needs to be replaced – then a 1GW swing away from band C/D requires 30MW more reserve

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Actual Cost

(applying estimated cost of £50/MWh to additional reserves)

- For a shift of 2.4GW to band B (as NG banding proposals) need to provide 70MW more reserve:

  Additional annual cost = £32m

- For a shift of 3.8GB to band B (CE thresholds) need to provide 110MW more reserve:

  Additional annual cost = £50m

Further Work & Questions

- Is the data for future generator connections correct?
- How can the SO use frequency response services from non-BM participants?
- Can we cost the baseline RfG position (Jan 2014 GB thresholds) against the existing GB Grid Code provisions?
- What are the costs to generators of complying with RfG in each band?
- Note that increased volumes of embedded generation mean this question would have to be addressed regardless of RfG

Costing – method #2

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Cost of Reserves

Start by using current day prices to produce an estimate of future costs

- For conventional gas units, average offer prices are £70/MWh in 2014
- When costing reserve we currently use an out of money costing which is an aggregated £8.30/MW/h across the day; this is the net Offer-Bid cost of bringing a unit on SEL to provide MEL-SEL reserve, then netting off the bid income of balancing the system to accommodate the additional SEL
- For footroom (balancing down) it aggregates at £4.00/MW/h for overnight periods.
- By 20/21, some of the time in order to balance energy after bringing on a unit to SEL for headroom at £70/MWh, control room will have to bid off wind units. Current average bid price is -£80/MWh
- Based on the load duration curve for 2020/21 presented estimate this to be ~15% of the time

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Volume of Reserves

- Operating reserve requirements in 2020/21 will be partially met by non-synchronous generation (and by ancillary services such as STOR and interconnector/pump storage response).
- There will also be a minimum requirement from synchronous generation
- Assumed 15GW wind capacity by 2020/21 (based on ~ 1GW pa growth that we are seeing at present). NB The load duration curve presented (slow progression scenario) estimates transmission connected wind at 13GW by 2020/21.

Reserve components: (assumptions/estimates)

- At 30% load factor the average wind reserve requirement will be 450 MW (10% of output as standard)
- 600MW LF & HF dynamic response is required on average which will need 1000 MW of headroom and footroom (based on 0.6 efficiency)
- Synchronised reserve for short term demand error and plant losses is estimated at 500MW (positive) and 1300MW (negative) – further assume that the negative reserve could all be met by bidding off wind.
- Total system reserve requirements are then approximately 3GW (which is roughly 10% of demand based on a 25-50GW range).

Total Costs

- 85% of the time enough synchronous generation is available to meet reserve using current ‘Out of Merit Costing Strategy’
- 15% of the time have to bid off wind and buy on additional synchronous generation (at £80/MWh and £50/MWh respectively) to balance energy and meet reserve requirements

Changing the amount of reserve available from wind generation (which then needs to be replaced in the calculations):

- For a shift of 2.4GW to band B (as NG banding proposals) need to provide 240MW more reserve:

  Additional annual cost = £52m

- For a shift of 3.8GB to band B (CE thresholds) need to provide 380MW more reserve:

  Additional annual cost = £82m