nationalgrid

Minutes

Meeting name	GC0048: Joint GCRP/DCRP Workgroup on National Application of RfG
Meeting number	6
Date of meeting	17 December 2014
Time	10.00 – 14:40
Location	National Grid House, Warwick, CV34 6DA (Room E5)

Attendees

Name	Initials	Company
Rob Wilson	RW	National Grid (Chair)
Sara-Lee Kenney	SLK	National Grid (Technical Secretary)
Alastair Frew	AF	Scottish Power
Amir Dahresobh	AD	Nordex
Andy Vaudin	AV	EDF Energy
Antony Johnson	AJ	National Grid
Campbell McDonald	CMd	SSE
Celine Reddin (Prev. Green)	CR	National Grid
Chris Marsland	CM	(on behalf of) CHPA & AMPS
Chris Whitworth	CW	AMPS
Ian Taylor	IT	EDP Renewables
Joe Duddy	JD	RES
Julian Wayne	JW	Ofgem
Mick Barlow	MB	S&C Electric Europe
Mike Kay	MKa	Electricity North West
Peter Bolitho	PB	Waters Wye Associates
Richard Woodward	RJW	National Grid
Sarah Carter	SC	PPA Energy
Steven Mockford	SM	UK Power Networks

Apologies

Alan Creighton	AC	Northern Powergrid
Chris Allanson	CA	Northern Powergrid
David Spillett	DS	ENA
Gareth Parker	GP	DONG
Garth Graham	GG	SSE
Guy Phillips	GP	EON
Jawad Al-Tayie	JAT	Cummins Generator Technologies
John Norbury	JN	RWE
Julian Rudd	JR	DECC
Mick Chowns	MC	RWE
Mustafa Kayikci	MKy	TNEI
Peter Thomas	PT	Nordex
Philip Jenner	PJ	RWE
Richard Lowe	RL	SSE
Rupika Madhura	RM	Ofgem
Tony Headley	TH	BEAMA
Zoltan Zavody	ZZ	Renewable UK

1 Introductions/Apologies for Absence RW

1. The Chair welcomed everyone to the Workgroup and apologies were noted.

2. RJW provided the workgroup with the new feedback form which is being trialled across the Grid Code workgroups. RJW welcomed the workgroup's comments. MK asked for an electronic version which RJW provided. The workgroup asked if the new feedback form would be used across the other Codes groups to which RW advised this is currently a Grid Code pilot however should the pilot be successful, there could be a view to extend this to the other Code groups.

2 Stakeholder Representation RW

3. The Chair noted the Stakeholder Representation as a standing agenda item for this workgroup and noted the workgroup is open to all but may need to be limited to one representative from each organisation should the attendance numbers become too large to facilitate and manage room capacity.

3 Review of actions & approval of minutes SLK

4. SLK ran through the Action Log and progress made to date.

5. The following actions were closed as complete: Action 16 'Assumptions Log', Action 17 'Insights from NGET Gas ENC Approach', Action 20 'Three priority items for the workgroup', Action 28 and Action 33 'Presentation Corrections' and Action 34 'New Standing Agenda Item ' DECC/Ofgem Steering Group Reporting'.

6. The Action Log was approved by the workgroup and will be updated and circulated with the minutes of the meeting.

7. SLK highlighted the previous meeting minutes have been updated with the changes received from Julian Wayne and Rupika Madhura.

8. The minutes of the previous meeting were approved by the workgroup noting the above comments and will be published in the 'workgroup' section of the Grid Code website[1].

4 Progress Update JW (on behalf of RM)

9. JW provided the Progress Update in RM's absence. JW advised the workgroup that the CACM (Capacity Allocation and Congestion Management) ENC has now been adopted following voting at the Cross Border Committee at the beginning of December and is now available for public viewing. MK asked if CACM is now European Law to which RW advised no, CACM is currently with the European Parliament prior to final approval and Entry into Force. AF asked could CACM still be rejected, to which RW advised possibly but very unlikely.

10. JW added the Commission drafting team should therefore be able to progress with RfG which the Commission has stated is next in line through the Comitology process.

11. CMD asked AJ about the approach to communications for existing offers and contracts in place with customers. AJ advised as per his action on this (Action 13 'RfG timescales within connection offer documentation'). He advised that this issue has been raised with the NGET Electricity Customer Connections Team and NGET Legal. AJ added that while the final drafting of RfG with respect to timescales is still unknown it is more difficult to know how to approach this and NGET wants to work with customers to ensure it is clear what obligations they have to meet and that they have sufficient time to work with their suppliers to meet the required timescales. It was also noted that manufacturers will require sufficient time to ensure they can produce equipment which is compliant with the RfG requirements.. CMD agreed, adding that without this clarity it is difficult to understand how many offers/agreements are affected.

[1] http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/Modifications/GC0048/#

12. MB asked did we determine what happens if plant is upgraded? AJ advised this is complicated and depends on what item of plant has been changed. It was noted that irrespective of RfG, this issue exists under the current GB framework in which a plant may be upgraded but the materiality of this change needs to be understood as this would affect the applicable requirements, for example is the plant changed on a like for like basis (as of the date of original commissioning) or is a completely new Generator to be installed). MB queried the example of new turbines being added to an existing wind farm. AJ advised that the new turbines would need to be Grid Code compliant but the issue of the wider wind farm was more complex and this had previously been raised at the Grid Code Review Panel RW added that the drafting on this in RfG was not clear.

5 Banding Data Sources RJW

13. RJW ran through the Banding Analysis presentation, to cover updates on data gathering and examples of generator compliance. RJW advised this was in relation to the next steps and would be used to clarify holes in existing data and clarity on data sources.

14. **Data gathering:** RJW advised the Large (Type D) TEC register data is currently the best available and covers Transmission connected plant and other BM participants. CMD advised that ‘Large’ is misleading wording as ‘Large’ is GB Grid Code classification not recognised in RfG. RW added the NGET TEC Register is just in relation to what NGET has contracted with customers in terms of TEC, and would not exactly match with all Type D plant. CMD added that the TEC register should contain Type D including in Scotland. RJW added that the Embedded information needs more work and referred to the action on SM, AC and MK to assist on this. RJW and MK advised that the Embedded data received to date was that provided by Electricity North West. SM added he is working on this internally at the moment. AF asked is this existing or new, and RJW advised it was restricted to new data.

15. MK advised it was difficult for them to know what will come forward in future, but they have an idea of Active Power Generation volumes (MW) (from DECC’s forecast and ED1 submissions) but not generation types etc. RJM advised this data sourcing will never be perfect and we will need to acknowledge what exceptions and assumptions have been made. MK added he has written to SSE for assistance in providing data.

16. CM asked is it worth speaking to the Generator’s for their data? MK added we could also use the NGET Future Energy Scenarios (FES) information. RW advised it is a good approach to use data which has already been used for price controls as it is already in the public domain and ensures consistency with other work. JW suggested looking at other angles such as planning restrictions, government targets etc. as another source of information to build a view on what size future generation projects might be.

17. RJW acknowledged there is an effort by all to get this data as best as it can be. RJW advised he will also undertake a ‘cleanse’ of the data once returned, to check there is no missing information or duplicates. CR asked if there is a timescale to complete this work to which AJ advised, there was a need to obtain the data as soon as possible as the remainder of the work would be dependent upon this data.

18. RJW welcomed suggestions from the workgroup on the data sources and approach, advising work is ongoing with a further update to be provided at the next workgroup meeting in January 2015 following receipt of DNO data.

19. CMD and RJW discussed potential attrition rate, and the need to capture assumptions in the analysis. RW advised the need to obtain the data set first and then examine attrition and assumptions.

20. **Generator Compliance:** RJW discussed how the banding analysis to date has focused solely on the profile of generating stations as a single unit not the configuration of any modules. AJ added the current Grid Code requirements are based on power station size (Large, Medium and Small) and going forwards under RfG (Bands, A – D) are based on either the Synchronous Generating Module level or Power Park Module (PPM) level. The implication of this (particularly for Power Park Modules) being that a Generator could decide to configure his plant and connections to slip into a lower and artificial banding, depending on their connection agreements. For example, a 140MW wind farm which should be caught by the Type D requirements could be connected in

discrete sub blocks with each sub block being treated as one wind farm. In this way the Generator would only need to meet the Type B requirements rather than the Type D requirements.

21. MK advised he expected PPMs would be in the main wind farms. RJW talked through an example of a 140MW wind farm (x5PPMs and x3BMUs) which is currently classed as ‘Large’ in Scotland and England & Wales and would be bound by the requirements of the Grid Code, CUSC and BSC. However those 5 PPMs fall under different bands (PPM1+Band C or D, PPMs 3-4 Band C and PPMs 2, 5 Band B or C). CMD argued this isn’t a real scenario and we shouldn’t be using extreme scenarios to set the banding thresholds that will apply to all generators. RJW advised this was purely an example but something the workgroup would need to consider. AJ added the key message from this work is to prevent a Generator falling into a lower band through configuration, connection arrangements or segregation in ownership.

22. CMD also queried the ownership boundary detailed in this example to which MK questioned whether the ownership boundaries isn’t an issue as this should be based on connection point as per RfG.

6 Cost to Generators CW/RW

23. RW introduced this agenda item to the workgroup by advising that the work to set the banding thresholds would require a balance between the costs attributable to generators (of complying with more onerous requirements) against those to the System Operator (of allowing generation to connect with a lower specification). The workgroup would need to consider all of these costs as part of producing a defendable case for the setting of national parameters including the banding thresholds.

24. CW addressed the group on his findings from an AMPS Manufacturer’s perspective for ‘small’ (Grid Code Terminology) synchronous plant. CW talked through the challenges of obtaining a view on costing or figures from other manufacturers. CW added from his discussions and work done on the expected impacts of banding changes and possible cost figures involved. He advised a standard industrial generating set provides a benchmark; the next level of cost related to a higher specification which would be considered to be the marine market with the highest specification being the military market.

25. For reference: the UK’s leading manufacturers of Hire-Sets design and build equipment packages which fall somewhere between standard industrial and marine specifications.

26. AMPS on first involvement with embedded generation didn't think a markedly higher specification would be required for grid connection (to fulfil GB-GC requirements). However it soon became apparent some additional cost would be incurred to ensure the embedded generator did not lose synchronism during Grid disturbances (V or Hz related) plus provide a capability to operate over the network +/- voltage range, and the required power factor range, particularly a leading pf condition.

27. AMPS member companies cannot be expected to disclose detailed costs as each strives to retain a competitive advantage.

28. In general terms an educated guess from within AMPS suggests that to retain saliency, increase inertia, provide additional equipment control functionality, and attain a conformity document, all being required for RfG compliance could combine to result in additional costs of up to 40% over and above a conventional industrial generating-set equipment package.

29. The difference between compliance at types B and C comes down to the need for more inertia, added safeguards to retain rotor saliency and additional kW of engine power to enable quick response for Type C Generating Units to provide frequency control.

30. The general opinion is that Type C has an additional 10% cost for hardware, and then 2 – 5% control system upgrades. For modelling and documentation (CW - most experience in 2-5MW generators) 2-5% additional cost would be incurred. Totalling these up, this would result in a 14-20% cost increase for a 2MW genset for compliance against Type C rather than Type B.

31. CW recapped on his colleague JAT's point raised under A.O.B at the last workgroup meeting (meeting 5, item 10, paragraph 55):

> "The need for RfG requirements with respect to Stand-By and Temporary Power support (Hire G-sets) equipment to be qualified with regard to an allowable time for which such equipment can be connected to a Network (grid) which would be of short duration in order to facilitate a step-less handover for a consumers load on return of a healthy Network (grid) supply".

32. AV asked is there a view for non-synchronous plant. CW advised their focus is synchronous plant. RW added that he and RJW have been in contact with Renewable UK in relation to non-synchronous plant. RW added there was a need to obtain costs for non-synchronous (wind farms, PV) which are likely to make up the majority of the new connections in Bands A to C.

33. AD asked how we would capture changes in the future. The workgroup noted this as something to consider.

7 Cost to System Operator — RW/AJ

34. RW and AJ discussed the consideration of the banding thresholds in relation to System Operation costs and advised this to be a work in progress requiring further workgroup discussion.

35. RW recapped that subject to Article 4(3) TSOs are required to set the thresholds within the maximum bands allowed by each synchronous area. RW added that you can reset the banding thresholds every 3 years but only within the maximum limits allowed in the ENC and again this would apply to 'new' generators/connections. In summary he advised you can adjust the banding down and up from the previous threshold but must remain within the maximum envelope set out in the RFG.

36. RW discussed that the Band B to Band C threshold would be the most important for GB due to the requirement for Band C generators to provide frequency response capability. CMD added that the point made on slide 7 '*The following analysis assumes all generators with frequency response capability can access this market'* is very important. RW advised Frequency Response issues are also being addressed through an existing Grid Code Workgroup "*Frequency Response Workgroup (GC0087)"* and will be discussed as a part of that workgroup.

37. For Slide 9 *'Projection of Generation Types by 2020 (Slow progression Model')* CMD, JD and RW discussed the change needed for wording on conventional generation (too simplistic/non-technical) and the need to use the terms synchronous and non-synchronous for publications. CMD advised of the need to quantify what the impact "actually is", rather than summarise with loose terms like "very little". CMD also added costs need to be quantified for what RfG is imposed on generators for providing a frequency response capability. RW advised the need to balance the costs on Generators against the System Operator costs. CW mentioned the rapid industry change (forward view) and suggested the need to understand this and what has happened in other Countries (e.g. Denmark, Germany) that have seen swift changes to their generation portfolio.

38. The Workgroup discussed the requirement of plant having the capability to provide frequency response but without necessarily having access to the market. JD added the need ensure the SO has access to sufficient volumes of frequency response and the two ways this could be achieved e.g. - through codes / agreements or the market. JW clarified that there are two barriers, market barriers and technical capability, and that this workgroup can't resolve the market issues so we should focus on the technical capability. RW added we can highlight concerns but are not placed to resolve them. This would be likely to require action under the BSC or CUSC.

39. RW summarised the way that the proposals had been developed based on 1GW of system reserve holding.

40. RW advised that 3 proposals for B-C banding thresholds had been considered in the analysis based on the original Jan 2014 draft for GB (10MW), the Continental Europe level (50MW), or the mid-point proposal discussed previously (30MW B-C threshold). RW advised that taking the original GB threshold of 10MW as a baseline, to move to the Continental European threshold of 50MW

would mean that 3.7GW of future Generation would move from Bands C & D to Band B. For the midpoint proposal (30MW threshold) this would be 2.5GW of generation. AF asked if NGET were assuming all the Frequency Response to come from 'new' generators. AJ and RW advised that no this was not the case but that to allow any objective analysis it had been assumed that frequency response was provided absolutely evenly on a pro-rata basis across the whole of the generation portfolio. JD queried why slide 16 assumed a figure of 3% instead of 2% of capacity to be the quantity of reserve that needs to be replaced. RW advised that this was an average between the peak and summer minimum figures of 2 and 4% respectively but recognised that this was entirely arbitrary although the latter condition is the most onerous for the SO to manage.

41. The Workgroup discussed slide 17 noting it to be an estimated cost as opposed to actual as per the title.

42. JW suggested RW submitting a list of assumptions made to the workgroup, so that the workgroup could provide more quantitative feedback and with a view to forming an agreed list of assumptions and data against which the rest of the WG analysis can be undertaken. JD also suggested sharing the more detailed spreadsheet of the calculations that under laid the presentation. RW agreed.

43. AF asked what is the current amount of Frequency Response available. RW and AJ advised they will look into this to find out. RW suggested potentially adding this into the graph - slide 9 *Projection of Generation Types by 2020 (Slow Progression model).*

44. MB noted that work done so far hasn't considered the demand side response market.

45. CMD questioned the interaction between this work and the views contained in the System Operability Framework (SOF). RW replied that while the SOF was only intended to be advisory and to show a direction of thinking, he would talk to colleagues involved and look into whether they could attend a future workgroup meeting with a view to giving a presentation. JW also agreed to speak to SO Ofgem colleagues for their thoughts.

46. AF added that the existing GB 'bands' (Small, Medium, Large – including the Scottish complications) at the moment do not relate to frequency response, so are we approaching this in the correct way? AF asked why did we have the differences? AJ advised this was born out of BETTA (British Electricity Transmission and Trading Arrangements). RW advised this was a good question and we would need to look into what the rationale for this was. RW mentioned the Fault Ride Through requirements associated with Band B and Frequency Response requirements for Band C as being the main differentiators between the bands in RfG. AF asked should we actually look at why we have the current GB banding arrangements? RW/AJ and AF agreed to take away internally to look into the rationale behind the current GB banding but noted they may not be able to confirm an answer on this due to the historical nature of the issue.

8 Update of Project Plan — AJ/SC/RW

47. AJ discussed the Project Plan including the RfG one Year GB Implementation TimeLine including the time frame for the proposed 6 modifications. He also noted the 'National Parameter Identification' work. AJ discussed that the plan aimed to complete in 12 months with a likely RfG Entry into Force (EIF) date of Q1/Q2 of 2015.

48. JW advised the 12 month process from start to finish as detailed in this plan is tight. MK believes it can be done it will just require the resources to be applied to achieve this. SM questioned, are we still intending to phase this work, AJ advised yes as there were some contingencies.

49. CR and AJ discussed the Modification timescales and joined up approach with SC. MK and SC didn't see DCRP would be a blocker in this process and can expand the DCRP meetings if necessary. RW also supported this approach for the GCRP. MB asked what happens if the process takes longer than anticipated on the plan? CR believes that enough time needs to be allowed and worked into the process. AJ added this process needs to be strictly controlled in making sure that it is just for the needs of RfG and is not side tracked by existing Grid Code related issues. MK added to take a similar approach to that which DECC/Ofgem had taken on BETTA or Offshore in terms of project management was pragmatic and sticking to the timetable would be advantageous. JW agreed that there may be a need to undertake more panel meetings if needed to help support the

process, and that the 12 month process set out in the presentation was by no means unachievable providing the mod development process is done at a higher tempo than normal.

50. CMD highlighted the risk of new plant being caught by RfG before the GB Implementation process is carried out and therefore before parameters are determined so the timing of application will be critical. CMD and AJ added we have to work together as an industry to carry out the RfG implementation such that contract timescales are facilitated.

51. CMD asked once RfG Enters into Force when do the new requirements come in? JW clarified that RfG Enters into Force once it has passed through Comitology process and is approved by the European Council and Parliament, and published in the European Journal. JW added RfG would not apply to currently connected plant, or (Jan 2014 draft) for plant where contracts had been let by 2 years after Entry into Force. These are the only criteria e.g. the 'applicable from' timescale (Article 63 of the Jan 2014 draft) is essentially not relevant in terms of what plant will be caught by the RFG.

52. **Dependencies:** AJ talked through the RAID definition (Risks, Issues, Assumptions and Dependencies) that would be used in the Project Plan.

53. **National Parameters Selection:** AJ ran through the very draft national parameter selection asking the workgroup for comment. He advised that this was a very initial view and had not been subject to discussion, analysis or study work. AJ advised the red text in the table applies to areas of further work, the yellow text applies to areas requiring further clarification (suggested from ENTSO-E) and black text applies to areas that map straight across ie where the parameters already used in the Grid Code either already match or are within the allowable range of parameters that are required to be set on a national basis in RfG.

54. RW asked if all the National Parameter work was intended to be done in one modification? AJ advised no and that it would be addressed in each relevant/applicable modification.

55. CM asked if for each value, could AJ advise the reasoning behind each parameter selection? CMD also asked if any associated Grid Code modification names can be added? AJ advised he would do this and also confirm any associated impacts to the Project Plan timescale of 1 year and highlight areas of joint TSO/DSO responsibility.

56. AF asked is this just for the Grid Code, which AJ advised yes. MK added he thinks that there isn't any parameter that is specific to the D code other than by reference to the Grid Code.

9 Development of a Risk Register — RJW

57. RJW talked through the action from the last meeting to create a Risk and Issues Register. RJW advised the draft Risk and Issues Register has been created on the basis of it being 'workgroup wide' only so it would include all Risks/Issues for GB RfG Implementation overall rather than just being NGET based. RJW added that National Grid will manage the administration arrangements of the Register.

58. RJW welcomed input and feedback from the workgroup on the Risk and Issues Register. Any Risks discussed in this meeting to date will be added.

59. The workgroup agreed to add the 'Risks and Issues Register' as a standing agenda item.

10 DECC/Ofgem Steering Group Reporting — JW (on behalf of RM)

60. JW delivered this item on the DECC/Ofgem Steering Group Reporting in RM's absence. The workgroup asked for a copy of the Terms of Reference for this group. MK advised a paper copy was provided at the JESG. JW advised he will look into this and provide a copy to the workgroup if possible [action now complete].

61. SLK talked through the placement of the Steering Group in the European GB governance framework and took an action to look to circulate an organogram depicting this.

62. JW asked the workgroup which items they wished to progress to the Steering Group and RW suggested timescales. MK suggested endorsement of the Project Plan. JW and RW suggested that Risks/Issues identified by the workgroup for escalating should be on the basis of wanting the Steering Group to do something, or to raise awareness across other ENCs.

63. JW advised RM had requested a detailed project plan by February ahead of the March Steering Group meeting.

64. JW also confirmed RM would be the point of contact for progressing the issues to the Steering Group.

11 Agree Actions SLK

65. JW to send the DECC/Ofgem Steering Group Terms of Reference to the workgroup [action now complete].

66. RW to provide a list of assumptions and further details behind the SO Costs - Agenda Item 7 presentation 'RfG Banding Threshold Setting Considerations' and circulate these to the workgroup.

67. RW and AJ to look into AF's query on what is the current maximum amount available of Frequency Response and also where possible add this to the graph - slide 9 "Projection of Generation Types by 2020 (Slow Progression model)" with the Agenda Item 7 'RfG Banding Threshold Setting Considerations' presentation.

68. RW to liaise with NGET System Operability Framework representatives and the potential for them to give a presentation at a future RfG workgroup meeting. JW to speak to SO Ofgem colleagues for thoughts.

69. RW/AJ and AF agreed to look internally into the rationale behind the current GB banding but noted they may not be able to confirm an answer on this.

70. RW and RJW to further investigate non-synchronous banding data/costs from Renewable UK.

71. In relation to the National Parameters Selection Presentation - AJ to provide workgroup with reasoning/values behind each parameter, any associated Grid Code modification names, confirmation of any impacts to the Project Plan timescale of 1 year and to review the TSO/DNO interactions.

72. SLK to look into the possibility of circulating to the workgroup an organogram depicting the DECC/Ofgem Steering group placement in the ENC governance structure.

73. AJ/CR/All to work towards a detailed project plan by February 2015 ahead of the March Steering Group meeting.

74. SLK to look to plan in future workgroup meetings from June 2015 onwards to the end of 2015.

12 AOB / Next Meeting SLK

AOB:

75. JW put to the workgroup, for cross-ENC Issues, how will such issues be raised? The workgroup discussed would this be an ECCAF task or progression to the Steering Group? The workgroup was unsure of the conclusion of this item but it is to be considered going forward.

76. The workgroup also discussed if a generator wishes to provide extra requirements beyond those required in their banding, for example a Type B wanting to fulfil Type C requirements, how would this be approached? The general consensus of the workgroup was that this is user choice and down to the user to arrange.

Next Meeting:

The next RfG Workgroup meeting will take place on **Tuesday 20 January 2015 at National Grid House**. Please also find attached below all future dates, arranged for this workgroup until June 2015:

(calendar invites have been sent out for these dates, please contact Sara-Lee if you have not received them)

- 17 February 2015
- 17 March
- 21 April
- 19 May
- 16 June