Minutes

Meeting name	GC0079: Frequency changes during large system disturbances - Phase 2
Meeting number	36
Date	23/11/2015
Time	10.30 – 15.00
Location	Energy Networks Association (ENA), Dean Bradley House, London

Future meeting dates

Meeting Number	Date
~~37~~	~~Mon 21st December 2015~~
38	Mon 25th January 2016
39	Wed 24th February 2016
40	Wed 23rd March 2016

1) Introduction & apologies

MK welcomed everyone to the meeting, including Frank Parker (FP) of General Electric who has joined the workgroup

2) Review of minutes/actions

Last meeting minutes

NVD comments from GM were accepted, so the approved minutes will be uploaded to the website by RJW.

Actions

GC0079 distribution list action [138]; It was agreed that RJW should issue an email stating that member's names will be included in the report. It would assume therefore that they are aware of workgroup proceedings and agree with the outcomes. Otherwise they would have the option to opt out and respond during an industry consultation.

FR data [148] – GS and RJW need to confirm what data is being used to illustrate the balancing services cost saving for the workgroup report. GS thought this may be difficult. RJW will re-word the action accordingly.

GS paper on RfG withstand requirement [139]; A document capturing the assessments required to develop a withstand requirement in tabular form was circulated. The table will be incorporated in to a paper for the Panels. Also need to plan for this to go to DCRP (March?). RJW needs to confirm the coordination back to GC0048 (RfG).

Over frequency [156] – ML explained that this stems from when G59/1 changed over-frequency to 51.5hz. This may have an impact on the retrospective application of any agreed settings change.

3) Workgroup report

MK discussed the strategy for drafting the workgroup report

- Risk of islanding (from University of Strathclyde report)
- Generation volume – from FES, Week 24 or similar source.
- Costs of managing the system - GS
- Extend the thinking applied to the Phase 1 estimate of implementing change – although MK will suggest a revision of Phase 1 costs more appropriate for <5MW generators
- CBA on changing to existing protection setting - break point of how far to go down to

JD suggested that the report could be structured to address or reflect the TOR. ML added that behaviour of vector shift was still important.

GS went through the standard structure of workgroup report template. He also suggested sections on:

- How the system operated now
    - How it will change
- Any NGET statutory requirements for operating the system
- Adam's work on risk assessments
- The cost-benefit analysis

MK recommended revisited the Phase 1 report structure.

CMD queried whether there would be one proposal on the settings change for the context of any CBA, which GS confirmed. MK explained that the CBA should be structured to see where 'sweet spot' is in comparison with alternative of doing nothing. ML one positive of our work so far is that mass market inverters are insensitive to ROCOF up to 0.7Hzs^{-1}, as this is arguably the biggest growth area for new generation this is important work already complete.

MK mentioned that the University of Strathclyde report perhaps presented an onerous view of islanding risk as it assumes synchronous generation would be in voltage control mode. This is perhaps contrary to initial workgroup opinion which assumed most generation would be in Power Factor Control mode. Clark and Bosch discussion suggested that wasn't the case for smaller machines. GM had previously brought up droop CT which feeds into AVR. This led to the paper which has been circulated for workgroup consideration.

The WG agreed that on the basis of the evidence to hand it appears that within the 3s of the NDZ used in the UoS modelling synchronous machines should be considered voltage responsive, as even if in PF mode, the PF control loop would be unresponsive in this short time period. However the effect needs to be quantified.

Reiterate action on MK to schedule meeting with small gen re voltage control and PF control modes

FP also suggested speaking to Aggreko, FG Wilson, and Cummins. He would find a contact from Aggreko and FG Wilson.

MK stated that Power Factor vs Voltage Control can be discussed with manufacturers, but CBA will help give a focus for savings vs cost of making change. The analysis would need BSUoS savings, as well as commercial considerations, and any need for generator risk assessments.

4) Operational Forecast and DG Data

GS confirmed that existing data sources underestimate PV proliferation (particularly FES), so he will try quantify the PV sensitivity. This will inevitably lead to the cost (and therefor potential savings) increasing for all scenarios **[ACTION GS]**.

For the largest infeed loss, JD asked about interconnector curtailment as an alternative.

GS mentioned the infeed loss figures all exclude Hinckley C (which would contribute a far larger loss). CMD requested an outline for the balancing services procurement process; he also thought it might be possible to get inertia without MW. GS suggested this may be possible further into the analysis period; battery/storage response solutions are geared towards the next 5 years.

JD discussed ROCOF limits for new plant - how far would/could you go? CMD asked that data reflects market signals for new plant being needed to support/gen mix/connection mix, rather than allowing the status quo to persist. Workgroup consensus was that a $1Hzs^{-1}$ capability for all new generation would be unlikely to create problems for manufacturers of either synchronous or asynchronous plant.

DG data sources

Feedback from DNOs has been received. NPG suggested data might be out of date so an update may be needed. However it was agreed that most of the changes since the WS24 submission were asynchronous plants, so less problematic for analysis purposes. GS was keen to avoid continually updating data in advance of the next formal submission in 2016. It was recognized that to assess the benefit, and costs, a view of the total number of synchronous and asynchronous machines, and associated MW, would be helpful.

Action - DNOs to provide numbers and aggregate MW of <1MW sites, split by synchronous/asynchronous.

Costs of making a change

	Protection Setting Change	Site Specific Risk Assessment	Mitigation	Total Cost
Max Number of Sites	178	132	53	
Cost Per Site	.010	.025	.100	
Sum (£m)	**1.78**	**3.30**	**5.28**	**10.36**

Table 9: Implementation Costs

GS recommended using the £10k per site estimate to develop an initial view of implementation costs. There was a query on the need for risk assessments; the workgroup generally believe this is not needed for non-synchronous plant.

ML suggested that mitigation actions might be not nearly as costly as a change of setting. MK would address this in a paper. **[ACTION MK]**

CMD suggested profiling costs for a sample site. Is a site outage needed? Will there be loss of revenue? MK's assumption was that any change would happen during a scheduled shut down, so no loss of revenue. He also felt the two year window to make change gives sufficient flexibility.

Regarding IK's question about what we can live with on machines with 0.125 Hzs^{-1} ROCOF (of any scale), GS believed an average pf 500MW of extra response would be needed 40% of the time according to the table. AH queried how much uncertainty there was with this estimate.

Action - GS to check assumptions driving change costs (links to DNO data gathering above) to give value of chasing last few MW

The group agreed engagement with the customer was critical. Contractors can't necessarily just turn up and change settings (risk assessment/health and safety consideration etc.). Ownership transfers also an issue

5) Costs of Compliance

GS presented the slides which expand MK's earlier paper. It considers two scenarios for managing the change.

For scenario 1, the generators make the change at their own cost. DNOs have a compliance/notification cost in chasing affected users. The up side for users is improved grid stability. BSUoS payers will see a saving in reduced SO actions. RJW explained the classification of BSUoS payers and will update both scenarios following the discussion. **[ACTION RJW]**

For scenario 2 – a fully funded administration and incentive activity – there was concern over the lack of cost control for generation making the change and expensing cost. ML also raised political issues for low income or old people's homes etc. making the changes at their own costs.

The slides suggest that the supplier could be run this activity given their access to site information. However the workgroup believed that as this was a technical change that they would not be well placed to lead the work.

The workgroup requested that interconnectors were added into the consideration.

As the workgroup were advancing on the consideration of costing and incentives, it was agreed that early engagement with Ofgem should be sought (following dialogue with Ofgem on the recommendations for Phase 1).

ACTION MK to write to Ofgem outlining workgroup progress and emerging thinking.

The workgroup queried consequential changes needed for any funding (especially if from BSUoS). It was felt the CUSC and BSC would be directly affected, GS felt NGET licence changes may be needed and this would not particularly straight forward to achieve.

ACTION Workgroup to review RJW's updated slides/Review feasibility of scheme within own organisations (DNOs suggested to consider alongside their COG rep)

6) System Inertia Limits Paper

GS presented his draft paper and asked for workgroup feedback.

CMD queried "user equipment" – is this *new* user equipment? MK felt it was actually both. CMD also queried the withstand capability of existing generation, and that a minimum inertia requirement should be an input into the level setting diagram. ML added that generation curtailment might need to be factored in too.

There was extensive discussion of the SOGL, and its possible requirements on TSOs to set frequency levels. GS confirmed his understanding of the approach today, and whether SOGL reflected this or not. It was hoped that any ambiguity could be covered off in the relevant EU work streams, especially the Ofgem/DECC stakeholder forums.

CMD mentioned another inertia workgroup possible being convened under another code (SQSS?). Their work (if it is happening) would clearly be important.

ACTION RJW to check on inertia work in other network codes

ACTION RJW to circulate SOGL and details of next DECC/Ofgem stakeholder meeting

ML reiterated the need to consider vector shift in ROCOF setting methodology (regional proximity and oscillation risks). He explained that if in the future it may also be necessary to set regional inertia limits as the real and reactive power swings during a disturbance will be greater if the system inertia is not reasonably uniformly dispersed. Such swings and their transient effects can destabilize RoCoF or vector shift protection. He suggested the 'developing requirement' section include a regional consideration.

8) AOB

9) Next meeting details

The workgroup reiterated a preference to have meetings in London for the foreseeable. The next meeting therefore will be on Monday 25th January at the ENA. RJW would also propose meeting dates further into 2016, avoiding clashes with EU meetings etc.

Attendees		
Name	**Initials**	**Company**
Mike Kay [Chair]	MK	ENA
Graham Stein	GS	NGET
Richard Woodward [Technical Sec.]	RJW	NGET
Andy Hood	AH	WPD
Joe Duddy	JD	RES
Campbell McDonald	CMD	SSE Generation
Sam Turner	ST	NPG
Ioannis Koutsokeras (by phone)	IK	SP Energy Networks
Martin Lee	ML	SSE Distribution
Miguel Bernardo	MB	UKPN
Frank Parker	FP	GE
Apologies		
Paul Newton	PN	E.ON
Greg Middleton	GM	Deepsea Electronics PLC