Frequency Changes during Large System Disturbances Workgroup Meeting 12
25 November 2013 at Midland Hotel, Manchester

Attendees

Name	Initials	Company
Graham Stein	GS	National Grid (Alternate Chair)
Robyn Jenkins	RJ	Technical Secretary
Mick Walbank	MW	Northern Powergrid
Julian Wayne	JW	Ofgem
Jane McArdle	JM	SSE Renewables
Martin Lee	ML	SSEPD
Joe Duddy	JD	RES
Andy Hood	AH	Western Power Distribution
John Ruddock	JR	Deep Sea Electronics
Greg Middleton	GM	Deep Sea Electronics

Apologies

Name	Initials	Company
Mike Kay	MK	Chairman
Paul Newton	PN	EON
Gareth Evans	GE	Ofgem
John Turnbull	JT	EDF Energy
Campbell McDonald	CM	SSE Generation
Mick Chowns	MC	RWE
John Knott	JK	SP Energy Networks
Brian Roberts	BR	National Grid
Alan Mason	AMas	Repower
Alastair Martin	Amar	Flexitricity
Adam Dyśko	AD	Strathclyde University

Minutes of the last meeting

The Workgroup approved the September meeting minutes. RJ noted that these would be published on the National Grid website following the meeting.

Review of assessment

GS presented the slides which were circulated with the meeting papers. The slides contained information on the background to the consultation.

JW noted that the implementation costs identified were against an assumed background because National Grid did not know the real numbers of generators affected. GS suggested that would be covered later in the slides, but using the actual numbers, the figures are largely unchanged.

GS noted that there were 5 main questions highlighted in the responses

1. Do the benefits of a change for >=5MW plant alone outweigh the costs?
2. Do the benefits outweigh the costs of implementing a setting change for all distributed generators (ie including plant <5MW)?
3. What's the impact of adopting a different setting (eg 0.5Hzs-1)?
4. What are the additional costs for new generators?

5. What is the cost of damage to generators due to an increase in risk under new settings?

GS added that the revised Cost Benefit Analysis (CBA) attempts to address the comments. The revised CBA is made up of the following;

- An updated projection of Balancing Services costs
- An updated view of implementation costs for plant at stations of >=5MW
- An estimate of implementation costs for plant at stations of <5MW

GS stated that the CBA does as presented does not incorporate the cost of damage to generators because successful completion of the recommended site specific risk assessment and any appropriate mitigation will minimise this risk of damage occurring. JR suggested that it would be correct to look at increased risk of damage to generators. MW suggested that acknowledging the risk does not change the conclusion as presented. AH noted that any costs from this should occur in the mitigation

ML noted that the Workgroup have not discussed the cost of mitigation or alternative solutions, adding that there is potential for checks using satellites, alternatively systems to check whether islands busbars are live. JD suggested that, unless the CBA includes, some estimates of the costs to mitigation, we are open to criticism that those costs have not been considered.

MW noted that the DNOs have accepted the increase in risk of damage to their equipment. JR questioned whether purposely running an island illegal. ML stated that running an island that is not earthed is illegal, running an earthed one is not. JD suggested that if such an event occurred, the DNOs would have to show that appropriate measures of mitigation happened. GS suggested that the logic was if there was a site where the risk was unacceptable then you would spend the money mitigating against it. GM suggested that, even if the DNO accepts the risk, the generator might not actually agree that the risk is acceptable.

ML suggested that the issue the Workgroup is trying to address is how to best estimate the mitigation costs for generators, and the way it has done this is by taking a number of generators, assuming a certain percentage of generators with RoCoF would need to have mitigation. ML added that, from a generators point of view, there could be two identical generators in different network situations and they have no control over who has to spend money. ML also suggested it could be cheaper to have check-sync or a system to block/delay auto-reclose, or similar instead of intertripping. MW suggested that, if you were to start with intertrip in the CBA at a certain cost, and the CBA is still positive then the process works.

GS suggested that, at this stage the Workgroup need to look at the evidence it has got and determine whether there is a case to propose the changes or not. To ensure a robust CBA it is necessary to look at highest estimate for costs and the lowest estimate for savings. ML noted that he does not think the approach is wrong but one of the questions from the consultation was about the level of cost, and the costs for this phase are low, because the number of generators affected is low.

JD suggested that this could be turned around, a different approach would be to take the cost of the saving then divide per generator and if the cost of mitigation is higher than that then there is no benefit. JD added that this could also work for the smaller end of the market RJ question whether that approach considered generators where the settings are already high and no change is necessary.

GM queried how mitigation for smaller generators would actually work, added that intertrip is not feasible for some of the smaller generators. JD suggested that the mitigation could be carried out a number of ways providing the legal drafting allows for flexibility in approach. GM noted that low-voltage generators have no knowledge of the network, it is the DNO who does. GM suggested there will be a feeling amongst generators that these settings will increase the likelihood of them staying online during a fault and they will have to pay for a intertrip or have a high risk of damage.

GS noted that he sees why it might help to incorporate the cost of damage into the CBA, but is still unsure if it is the right thing to do that as the Workgroup's recommendation is that actions are taken to minimise this risk appropriately, albeit at a cost to the affected generators. GS added that if damage costs are added, then indication of the potential number of incidents is also necessary and there is some feedback on this in the consultation responses. MW suggested that, although it may not make a huge difference to the CBA, it will make it more complete.

ML suggested that if a system which blocks auto-reclose is installed as mitigation it will only have to be paid for once, and even if it is expensive individually, it will allow for the connection of other generators without incurring further costs. GM suggested that it would be useful to have some numbers to support this. JR noted concerns over how long such as system would block the auto-reclose. ML suggested that it would block the auto-reclose until the busbar is dead. JD noted that the statement infers that you could, potentially, sustain an island for a very long time. ML suggested that, in theory, a sustained island could happen, but only if local generation matched local demand.

GS surmised that, in the revised CBA, the potential cost of damage to generators needs articulating without suggesting that the Workgroup believes that an inappropriate level of risk of damage is acceptable.

The Workgroup queried what the additional costs to new connectees could be as there have been none identified. ML suggested that it could be the difference between the cost of standard equipment, and the cost of equipment to meet these settings. GM suggested that it could be where new connectees have to pay for an intertrip or pay the DNO for extra protection.

ML noted concerns that these proposals may push generators towards installing Vector Shift on synchronous generators as an alternative to RoCoF. In Ireland the studies have shown that Vector shift does not operate because the synchronous generator stops it from working. GM noted that both RoCoF and Vector Shift are widely acceptable across Europe. JR added that, over last 15 years, he has seen the smaller generator market moving from RoCoF towards Vector Shift. ML added in Ireland studies have suggested Vector Shift is not appropriate because it can fail to trip in certain circumstances. JD suggested that is outside of the current scope and is for the DCRP to consider if changes are necessary.

MW suggested that DNOs could insist on installing intertrips. GM noted that he would expect the DNOs to pass the costs of those to generators if it is something they need to achieve connection. ML noted that where there are multiple generators, it makes sense to put an intertrip on the DNO side rather than having individual intertrips. ML noted that much of the discussion is moving into the sub 5MW and multiple generator category adding that, for the current phase, he is happy with the proposal and CBA.

GS reiterated the assessment aims to ensure the savings outweigh costs with enough certainty to proceed and it generally considers the high end of costs and low end of savings.

GS stated the assumptions the costs of implmentation were originally based on, noting that of the total synchronous generator population, around 20% would need mitigation. GS added that the DNO data gathering has provided some actual numbers but they do not increase the total number of sites affected. The latest view of generator data is consistent with the assumption of £10million implementation costs, although within that number it is acknowledged there are some significant costs for individual parties. For smaller than 5MW sites, it is more difficult to estimate costs as there is less information on them available. There is deemed to be up 6GW of plant connected which includes around 1.5GW of Domestic PV. GS noted that Domestic PV is assumed to use proprietary techniques. ML suggested that the effect of that technique during a fault is unknown. JR queried whether SMA is included in the Workgroup. RJ added that a member of SMA is a Workgroup member by circulation as they did not have the resource to commit to attending meetings. GM suggested that SMA could provide information on whether they will be affected or whether they have tested any PV during RoCoF events.

JW questioned why the phase two implementation costs are being included in the phase 1 CBA. GS added that to determine the full benefits the full extent of the costs needs to be considered. JW suggested that the question of how far the benefit of phase 1 goes, is a different question to understanding the full extent of the benefits.

GS suggested that lower voltage generators are expected, when take 'on average', to be a simpler implementation, because they are a standard piece of equipment connected in a standard way. JR suggested that it would still depend on the site specifics. GS added that it is difficult to be specific on costs; a generator owner would not spend more changing a setting that the total cost of the installation. GM noted that the cost of the protection unit is fairly minor compared to the cost of the set. JD countered that the smaller a generator gets, the less likely that assumption becomes.

GS highlighted the scenarios, which can be found on slide 11, and suggested that £30m should be adopted as the plausible worst case for he purposes of this assessment.

JR queried whether the DNO will also want to check the setting changes. MW suggested that it could depend on who the generators consultant is, if it is one the DNO know and are confident in then they may not witness the change. AH added that there is no requirement to witness the test, only a requirement to carry out the test.

GS suggested that, of the two scenarios presented, the hybrid approach may be the best way of coming up with an estimate, as there will be variation across different installations. JR suggested that across low voltage sites, it is what happens to the voltage that could give everyone problems. AH stated that this proposal is to mitigate against a national event where a large genset comes off the system and causes a national frequency event.

GM noted that the £30million figure is conservative as it is dependant on whether the generator needs to install intertrip. ML added that he is content with the number but is concerned that we are putting numbers to things where information is incomplete. MW agreed that we do not know what the details are, but suggested that we can be comfortable because this cost is at the high end of the market.

GS noted that National Grid have a projection of balancing services costs, calculated up to 2025/26. GS added that the calculation model uses 2012/13 generation data, with the wind generation and interconnectors scaled up as the years progress, the scaling in line with the "Slow Progression" UK Future Energy Scenario. GS noted that this does not include solar PV due to uncertainty over future volumes and load factores. The costs indicated are for managing existing infeed loss risks, new infeed loss risks and are split for a change to 1.0Hzs^{-1} and 0.5 Hzs^{-1}. As there are always uncertainties in any modelling GS explained that he had created 3 estimates;

- Best view assumes good trading capability, increasing synchronous plant flexibility and reduced wind generation output
- Central view assumes average trading capability and increasing synchronous plant flexibility
- Worst view assumes average trading capability, no development in plant flexibility, windier conditions and earlier connection of new infeed losses

GS noted that the cost of carbon has not been included but could be worked out. JM queried what no development in plant flexibility means. GS suggested that the presumption is that over time, if the System Operator needed to keep buying extra plant then it is likely there would be a market response to the need for flexibility. ML questioned what the extra risk in 2017 is. GS noted that there are conneciton agreements for new gas fired stations which are bigger than 1320MW there are also areas where a combination of gas fired and wind farms lead to a larger infeed loss.

GS explained, based on the central case, break-even is achieved in the first year if all generator's RoCoF settings are raised to 1.0Hzs^{-1} and break even is achieved in 2 years if only the greater than 5MW plant is modified. GS asked the Workgroup whether there is different way of presenting this information.

MW questioned the total cost of balancing services. GM suggested that if generators see these numbers they may insist National Grid pay a share of the costs due to the size of the savings they will make. GS explained that the balancing services costs are borne by generators and suppliers. JM noted that it would be interesting to see what proportion of the costs goes to what type of generator. JD noted that his understanding was that this was linked to constraining large generators to minimise the infeed loss. GS indicated that there is a difference in the types of actions taken, if trading occurs then the overall number of actions are lower. GS added that, this year, National Grid have taken actions on around 130 nights.

GM questioned whether there would be benefit in specifying a setting of 0.5 Hzs^{-1} now and then move to 1.0Hzs^{-1} at the end of the decade. GS suggested it is worth considering but we would need to consider new generators. JD indicated that there are two issues, protection settings and withstand requirements. Two protection setting changes mean potentially double the cost, but for most large generators their withstand capability is unknown and will need to be calculated, and in those circumstances it would be sensible to only do that once.

JW queried whether there are any figures for changing only the greater than 5MW plant to 0.5Hzs^{-1} as the benefits of moving to 1.0 Hzs^{-1} rather than 0.5Hzs^{-1} are only realised in 2022. ML questioned whether, in moving to 0.5Hzs^{-1} when there could be a lower volume of generation on the system, the system operator would be able to bring the system back into control, whilst remaining within the frequency limits. GS suggested that National Grid would have to have around 1.8GW of fast acting frequency response around at any time to control frequency.

ML suggested that 0.75 Hzs^{-1} may be a compromise which will give generators more comfort.

GM asked whether new generators design their power station design to a ride through rate.

GS asked whether there are additional elements which need to be incorporated into the CBA. GM suggested that there is still a question mark over the implementation costs but even if it doubles the benefit is clear. JR asked whether the CBA should show where the money is going to go. GS noted that it will be passed back to the industry and ultimately consumers.

JD suggested that GS might want to look at the reduction in inertia and the costs of additional frequency response.

GM asked why the cost of carbon has been dismissed. GS noted that it was because simply because he didn't have the information available at that point.

JD suggested adding a row detailing the total balancing costs for each of these years to put the potential costs and savings into context. GS noted that he can include this year's projected total but adding a year on year total is unlikely to be possible. JR questioned who the audience for this work it. RJ stated that all Workgroup material is made public. JD suggested that some of the trade associations would be interested.

JM suggested that as the benefit is so high, and the cost difference between the two is settings is not a lot different then 1.0 Hzs^{-1} looks sensible. ML noted that there has been no analysis done on smaller plant so it is unknown whether the DNOs will find that risk acceptable. GM suggested that clarification is needed it looks as though 0.5Hzs^{-1} is almost as good as 1.0 Hzs^{-1}.

AH questioned whether the smaller than 5MW generation is cut off at 1MW. GS noted that the only information National Grid have access to is down to 1MW. ML noted that AD has done a lot of work on protection settings and, as such, ML feels confident that changing smaller machines to 0. 5Hzs^{-1} would be safe. ML added that he would be comfortable for inverter and induction machines to go to 1.0Hzs^{-1} and for synchronous to move to 0.5 Hzs^{-1}even if it has to be changed again in the future. GS questioned whether that proposal would be for new and existing generators. ML suggested it would be and in the future generators may be using voltage control.

GS suggested that there is a risk is that you then connect this plant, but have to run the system at a RoCoF limit consistent with the new plant. ML suggested that as wind and PV are the dominant generation on the system, then a two level RoCoF limit may still yield many of the benefits. ML added that the Workgroup still need to assess multi-machines islands before determining whether the benefits of 1.0Hzs^{-1} can be fully realised.

JW queried whether there is any indication of how many greater than 5MW generators are synchronous and non-synchronous, adding that there is a possibility of someone asking why there is a blanket approach with regards to settings when only one category of generator is likely to incur any damage. GS noted that it may not make sense for some large synchronous generators to make changes if, for example, they plan to decommission their plant soon. JM noted that, in Ireland, the generators are promoting the concept of a sub group of generators who should not have to meet higher RoCoF withstand requirements because of their running regime; they may be peaking plants who are unlikely to run in high wind conditions.

ML noted that in the consultation responses, generators inferred they were more comfortable if the move is to $0.5Hzs^{-1}$, as they have experience or knowledge of this without going into the detailed engineering assessments, whereas a move to $1Hzs^{-1}$ would mean more work. ML suggested that the proposal should be that if it is an induction machine or inverter generator then change to $1Hzs^{-1}$ and change synchronous generators to $0.5Hzs^{-1}$ with a statement that in 2022 we are moving to $1Hzs^{-1}$. GS suggested that the proposal should say change generators to $1Hzs^{-1}$, with a minimum of $0.5Hzs^{-1}$ for synchronous generators by exception. ML reminded the Workgroup that we do not want to push people towards vector shift. JD suggested that if G59 protection settings have to be agreed with the DNO then, you could say sorry we are not accepting this anymore, particularly if there is evidence that Vector Shift is not acceptable.

GS noted that there is a DCRP meeting on 5 December at which a proposal needs to be presented. GS surmised the Workgroup discussions to three potential options;

- For all plant at 5MW or above RoCoF should be $1Hzs^{-1}$
- RoCoF should be changed to $1Hzs^{-1}$ for non-synchronous generation and $0.5Hzs^{-1}$ for synchronous plant
- RoCoF settings should be $1Hzs^{-1}$ for non-synchronous generators and something different for synchronous which may use derogations. MW added that the DNO would have to apply for any derogation, so the generator has to convince the DNO if they would like a derogation. JW suggested caution over a proposal which suggests using derogations.

JR noted that, if the generator is not exporting power and you lose that connection, then their settings do not matter to National Grid.

GS noted that one option could be to specify the exception process to plant, e.g. to explain what a plant has to do to demonstrate they cannot meet the requirement. AH noted that in the current Distribution Code there is an exception for where a situation may cause damage. GS queried whether that would suffice for this proposal.

JM noted that the CBA has shown some interesting figures. AH queried whether, if different settings for synchronous and non synchronous are specified, then would there be a single setting for all new plant.

GS summarised that a potential Workgroup proposal is to change RoCoF to $0.5Hzs^{-1}$ for existing synchronous generators and $1Hzs^{-1}$ for all other plant. ML suggested adding a requirement that from 1 April 2016 all new technology is set at $1Hzs^{-1}$.

JM asked whether cost recovery will be discussed anywhere? GS noted that it is out of scope of this group, but could be discussed in other forum.

Notes from the previous meeting

GS suggested that the comments should be discussed by exception and if there is anything needing to be flagged, particularly which affects the DCRP, then Workgroup members should notify GS or RJ as soon as possible, whereas if there are other points the let National Grid know within a couple of weeks.

Phase 2 update

GS noted that the ENA have drafted a timetable for the work packages. The headlines are a procurement exercise which runs through to 2014, meaning work on this phase will start in earnest in spring 2014 at which point input from Workgroup members will be needed, there are likely to be some outputs in summer 2014.

Actions

The Workgroup discussed the ongoing actions, details of these discussions are captured in the action log.

AOB

JR noted that he will arrange for alternator manufacturer to present at a Workgroup meeting.

Date of next meeting

RJ noted that the next Workgroup meeting will be the 16 December; GS added it will likely be by teleconference.