Frequency Changes during Large System Disturbances Workgroup Meeting 10
29 September 2013 at Midland Hotel, Manchester

Attendees

Name	Initials	Company
Mike Kay	MK	Chairman
Robyn Jenkins	RJ	Technical Secretary
Graham Stein	GS	National Grid
Julian Wayne	JW	Ofgem
Jane McArdle	JM	SSE Renewables
Adam Dyśko	AD	Strathclyde University
Joe Duddy	JD	RES
Andy Hood	AH	Western Power Distribution
John Ruddock	JR	Deep Sea Electronics

Apologies

Name	Initials	Company
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
Martin Lee	ML	SSEPD
Brian Roberts	BR	National Grid
Alan Mason	AMas	Repower
Joe Helm	JH	Northern Powergrid
Alastair Martin	Amar	Flexitricity
Greg Middleton	GM	Deep Sea Electronics

Minutes of the last meeting

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

Actions

The Workgroup discussed the ongoing actions; details of these discussions are captured in the action log or on the meeting agenda.

Review of Workshops

Feedback from Workshops

RJ noted that notes from the two Workshops were circulated with the Workgroup meeting papers.

MK summarised for the Workgroup that in London there were notable questions on who would bear costs, with the remainder concentrating on a the process which the Workgroup and AD followed. MK noted that there was a question on the reduction of risk if auto-reclose dead times were extended. The workgroup agreed to revisit this later in the meeting.

GS suggested that, overall, the attendees went away with a far better understanding of AD's work and clearer picture of who is and is not affected.

GS explained that, at the workshop in Glasgow, there were questions on how the Workgroup determined the size bands, along with questions on costs and the effects on the machines due fatigue.

JR queried what is meant by the question who bears what costs. MK explained that this question is asked to determine who has to pay for making the protection setting changes, and the Workgroup's working assumption is that whoever has to make the changes and owns the equipment would have to pay.

MK queried whether the Workgroup think the workshop reached all necessary parties. GS suggested that they may have to be repeated once the implementation method has been developed and to discuss phase 2. MK proposed that some smaller parties may only be interested in what the Workgroup are definitely proposing rather than "what ifs" so they may only engage once there is a decision on the setting.

JR stated that there are still questions over the measurement of RoCoF. AD noted that some relays, including the DSE relays, can have measuring period as a setting, whereas some other relays cannot. MK added that there was some work done by the ENA on this. ETR 139 highlights some of the technical requirements for RoCoF. MK suggested this discussion continues offline and RJ agreed to arrange a teleconference. JR noted that a separate conversation would be needed as there are times where neither RoCoF nor Vector Shift can work. GS queried whether there are examples of when that has happened? JR suggested that there may be examples. MK noted that this Workgroup has not spent much time actually discussing that but there was evidence from the G59 Workgroup where there was an MOD site which did not have G59 and there was some evidence of damage. JR suggested that this could happen where a generator is running in parallel as a standby with approximately zero exchange of active and reactive power. AD indicated that the generator should start to slow down if there is no power going in. MK questioned how a generator would get islanded with no load and why would a generator on a DNO network be running with no load? MK noted that the Workgroup has been looking for examples of this and asked JR to see if he can find any.

Change of auto-reclose settings

MK stated that most of the auto-reclose equipment being installed on the Distribution Networks have programmable dead times and most DNOs have programmed them to 3 second dead time. JR suggested that if the ride through requirements become more stringent then the short dead times may not help. MK explained that, at the London Workshop, the idea was raised that the DNOs could look at lengthening auto-reclose time to reduce the risk of non-detection of islanding and subsequent out of phase reclosure. MK suggested that most of this plant in the 5-50MW category is connected at 33kV where much of the auto-reclose equipment is easily programmable. MK questioned whether it is worth thinking again about the risk assessment to see if increasing autoreclose reduces the risks identified.

AD noted that when the model was re-run with a 10s dead time rather than 3s it appears to reduce the risk by half but that is only half the story. The model used an NDZ detection time of 3s, this would also need to be re-run with the longer period factored in, but it would probably reduce the risk further. GS agreed to consider appropriate further work.

MK suggested this could become part of the discussion at those sites where generators have to do further mitigating studies because it could be a cost effective mitigation measure. JD questioned how the generators and DNOs who are discussing the risk of out of phase re-closure come up with the calculation? He suggested that if we want to say this is a mitigating tool, we should probably support that with some discussion/evidence. AD agreed that guidelines could be helpful. JD asked whether a risk assessment tool could be provided which would use some general rules to determine whether dead time has an impact on the above risks. AD noted that he would have to take it away for consideration.

JW asked whether the risk decreases as re close times increase because a generator is more likely to trip on under or over voltage. GS noted that it would be because the generator is more likely to move out of voltage limits, AD added that the longer the period, the more likely the generator protection is to detect the fault. MK added that the longer the detection window, the more chance a change in demand is likely to cause the generator to trip off. JW suggested that other lengths of times could be considered, for example it may be that 5s could deliver 90% of the benefits of 10s.

GS noted that the Workgroup has highlighted that auto-reclose has an effect and so it can be taken into account during site specific risk assessments, in addition we could make a general statement that the risk reduces by “x amount”, but as there is no national average setting a site specific assessment is required. MK stated that without a tool or method the DNO will not know how much effect lengthening the auto-reclose setting will have on the risk. GS suggested that with such information and anymore received in the consultation responses we can make a statement which says “in your site specific risk assessment these are the things you can look at ” and include intertrips, change in timing. GS added that the next step is to review the responses and think about what the risk assessment needs to factor in, he suggested that this is a discussion for next time following the consultation closure. RJ agreed to ensure the consultation responses are grouped and circulated ahead of the next workgroup meeting.

AD explained that he recently had been involved in discussions on using a voltage level indicator as a blocking signal on the auto-reclose. MK suggested that this is an easily understandable idea but it may not be easily implemented as there is not always a VT on the 11kV network. MK added that this is proposed because the quality of the voltage measurements required was not as high as required for the synchroscope as it could be for this. JR suggested that this could be a development for the future when the DNOs are replacing switchgear.

GS noted that RfG article 12.2b requires all type B generators to have voltage control, Article 10.2 and Article 16.2 require Type C asynchronous generators to have frequency control and a different control method which could include voltage control. If frequency and voltage control is to be deployed as a matter of routine on distributed generation, then RoCoF may no longer be a viable method of detecting an island situation. MK added that there is a point where the DNOs will have to start thinking about this, it could form phase 3, of this work. MK noted that he took an action from ENFG (Electricity Network Futures Group) to start teasing out what needs to be done in this area. MK added that control range will probably not change for existing plant. GS noted that in the consultation we have been quite clear of the interaction between control philosophy and RoCoF, so not considering all options does not seem quite right, it is probably a case of being aware of what is going on and bearing it in mind when looking at the next steps. MK queried whether this comes back to why we insist on not having islands, adding that there could be something in the way we design in future which, going forward, means we could allow islands to persist. However, at present, once there is a public network involved it is breaking the law every time there is an unearthed bit of network. MK acknowledged that there are lots of reasons why islands are undesirable and it was easier to make the generation disconnect but that is a more difficult position to sustain moving forward with all the other things involved and there may be a need to reconsider DNO design philosophy.

JR queried whether there would be any adverse effects or unnecessary risk on automatic mains failure equipment, which starts in 5 to 15 seconds if there is a mains failure (e.g. generators in hospitals). As mains failure starts the timer, this equipment could see a lot more starts if they have a start time which is shorter than auto reclose. AD suggested that the majority of plant has 10s start times.
GS stated that the answer to a lot of these questions are down to what the network look like in specific areas. JR agreed to discuss with AMPS and seek further information.

MK noted that despite DNO design philosophy not forming part of the terms of reference there is still a need to articulate the RfG requirements for LOM and the possibility of changing the DNO design philosophy to include islands.

Update on work packages

GS explained that at the September ENFG, he presented a single paper which defines two projects, the two proposals which were discussed at the previous [ENFG?] meeting. The first work package is to conduct a survey of what generation is installed, its general characteristics and how it would behave in an island. The second work package is similar to the UoS study in phase 1 however it is dependant on the completion of the first phase. GS stated that the paper asks the ENA to seek proposals for organisations to do the work. The paper also highlights that the network licensee Workgroup members will have to contribute expertise. The ENFG agreed that the ENA move forward with seeking proposals.

MK stated that further discussion between the DNOs and NGET are needed to work out the sharing factor for funding.

GS stated that the paper will be published as a Workgroup paper on the National Grid website meaning anyone who is interested will be able to view it.

JD asked what is the ENFG and its purpose? MK explained that anything distribution related is done through the ENA as they are service providers to the DNO for the Distribution Code, and they are the legal entity and trade body for the network licensees. The ENFG is the meeting of engineering directors to govern the ENA activities, the group is used a lot, particularly when initiating new work.

MK asked how the Workgroup can assist with the work packages? GS noted that assessing multi-machine islands is planned as part of phase 2 and it would be useful to discuss this with some of the Workgroup members to check the scope of the two work packages is achievable before work is started.

AD suggested that modelling multi-machine islands is much more involved, the number of possibilities is high and it requires the first phase of this Workgroup's work to conclude to provide a much better picture of what scenarios can be expected. GS added that there is also thinking required on what types of the network configurations should be used. GS requested Workgroup members think about how they could contribute.

AD suggested that the most reliable way of modelling the smaller generators may be lab testing of the units. MK noted that, in Germany, the least cost option seems to be swapping the whole inverter, he added that it has been agreed that the costs of that project will be socialised but the program has not started yet.

JR noted that in the inverters he is familiar with, ROCOF or vector shift are currently single events and there is no time delay. MK suggested the Workgroup need to capture these things in the work package specification, and suggested those who have any thoughts send them to RJ for inclusion.

JR queried whether the Workgroup knows which relays are commonly used. MK stated that the Workgroup has a list which was circulated with the first letter to generators. RJ agreed to send to JR.

Development of withstand.

GS presented the slides which were circulated in advance of the meeting. He explained that they illustrate what National Grid can model using the information and plant models available to it. He added that we can also do a comparator with Fault Ride Through requirement. GS noted that these figures should be taken as illustrative rather than definitive.

AD questioned why there is an increase after a longer time? JR suggested it depends on the generator controller. JD queried if the increase in torque is a feature of the DG in droop.

Comment [J1]: Increase of what?

MK queried whether these studies are steady state? GS responded that they are dynamic studies . AD suggested that the results were linked to the generators' H parameter quite directly.

JM explained that DNV KEMA did some work in Ireland and suggested that during RocoF the torque it is a lot less than it is during Fault Ride Through but they based that study on the typical generators in Ireland and on assumed parameters so it may not be directly relevant. GS suggested that the Workgroup could follow the same evaluation framework as DNV KEMA.

JM explained the situation in Ireland, with regards to SSE's plant and the next steps there, noting that desktop studies may not be enough; and in some circumstances they may have to consider live testing.

MK asked Workgroup members whether they know how machine designers cope with fault ride through historically. JR suggested most of the alternator manufacturers are only designing for a 3 times overload event but they are investing heavily doing tests for fault ride through.

JW queried whether manufacturers set Fault Ride Through limits, where if the generator exceeds the limit it voids the warranty for instance? JM – stated that she is not aware of this happening.

MK suggested that there appears to be a need for a metastudy looking at all the relevant work from around the world and conducting a gap analysis done to see if there are any gaps for GB systems or generators. MK added that this work should be led by National Grid with help from the workgroup.

JD noted that one of the problems in Ireland has been trying to contact the manufacturers of plant which has been connected to the system for a long time.

JR suggested the when there is a rapid change in frequency, there is a consequential increase of current (inertial response), and if the current goes too high then circuit breakers would trip. It was noted that Large transmission connected generators probably already take account of inertial response when proposing protection settings, but this may not be the case for embedded generators.

GS noted that ride through requirements will have be retrospective, and we need to be clear that all plant will have to withstand a specified rate.

JM advised the workgroup to monitor the work in Ireland, noting that the real tests are expected to commence in 2014 and Irish Regulators are expected to make a decision in October or November at which point they will publish all of the consultation responses.

AOB

JR suggested that RoCoF is not the full extent of the problem; the electrical effects are also a problem. JR added that to date, the Workgroup has not discussed methods of detection. AH noted that phase 2 contains a review of vector shift. AD added that Vector Shift is believed to be less sensitive. JD suggested JR review the Terms of Reference to ensure there are no gaps in the work program.

MK noted that the effects of 400kV faults can be seen at lower voltage levels and this Workgroup is focussing on the issues on the Transmission network which can cause a ripple effect across the whole system and the purpose is to prevent DG tripping and worsening the situation. MK queried whether there are any other effects at lower voltage levels.

JR suggested that there is an effect on current, a Transmission fault means the generator could convert kW to VArs which could cause an increase in current.

Next Meeting

RJ stated that the next Workgroup meeting is scheduled for 21 October. MK added it will be at the Midland Hotel again.