Frequency Changes during Large System Disturbances Workgroup Meeting 7 20 May 2013 at Electricity North West Offices, Manchester

Attendees

Name	Initials	Company
Mike Kay	MK	Chairman
Robyn Jenkins	RJ	Technical Secretary
Martin Lee	ML	SSEPD
Graham Stein	GS	National Grid
Brian Roberts	BR	National Grid
Jane McArdle	JM	SSE Renewables
Adam Dysko	AD	Strathclyde University
Julian Wayne	JW	Ofgem
Joe Duddy	JD	RES
Joe Helm	JH	Northern Powergrid
William Hung	WH	National Grid
John Knott	JK	SP Energy Networks
Andy Hood	AH	Western Power Distribution
Alan Mason	AM	REpower

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

Minutes of last meeting

The workgroup approved the minutes for publication.

Risk assessment

AD thanked the DNO representatives on the workgroup for their load data noting that where there were uncertainties in the data the worst case scenario was chosen.

AD explained how he had treated the Electricity North West data, which consisted of 4 days of measured data combined as a week from one urban and one suburban primary. These were used to create a dataset for weekdays and weekends. Reactive power changes were observed from plots of the data, but the workgroup suggested that these may not be as a result of a real load reactive change, but that a transformer has tap changed and the adjacent one has not meaning there may be some circulated current. AD agreed to see if this can be investigated any further in the final report.

AD noted that for the NDZ assessment the simulation took place in a real-time simulater with the relay set at 11 different setting options. The real-time model is a 30MVA machine connected to 33kV and a 3MVA machine was used for spot checks. Balanced conditions were simulated then generation or load was increased or decreased until the relay operated.

AD provided an overview of the initial results noting that on the real power NDZ results summary, a negative result means the relay tripped under acceleration, power being exported, whilst a positive result indicates a trip under deceleration. The zero results demonstrate where is was not possible to set up a sustained island with LOM, the relay would trip within 3 seconds, which was the specified time limit to detect the islanded condition. AD noted that the application of PV control provides very good stability for a power island.

AD noted that the risk had been calculated, using the assessment probability tree and a list of assumptions;

- Generation range considered 5MW –50MW
- Existing Synchronous DG Generation included only
- 8 different load profiles included
- Generator output is 100% its rating at *pf*=0.99 (lagging) –based on SPM generation record
- Max. permissible length of undetected island is *TNDZmax*=3s.
- Loss of supply occurrence –96 times in 7 years a population of 440 substations.
- P and Q NDZ assumed from the WP1 results
- All SM generators have ROCOF

AD noted that for each of the 8 load cases there are results for the 11 setting options and the 4 parameters for fixed power factor and 4 for fixed impedance load. AD suggested the load cases can be categorised into two groups, around 10^{-5} or 10^{-3}. To confirm, AD carried out further load tests using spot measurements. The results demonstrated a difference of 2 orders of magnitude between the 1second and 30minute data, so for the final results all of the low resolution data has been discarded. AD noted that on the graphs 10^{-11} represents zero.

AD noted that the results are based on worst case scenario and have been derived to two characteristics, the individual risk, which indicated the probability of a person in close proximity to an undetected island being killed and risk of out of phase reclosing, the probability of out of phase auto reclosing action following a disconnection of a circuit. MK noted that, as these are based on the worst case scenario, the individual risk is likely to be pessimistic. JD suggested that these characteristics should be renamed as probabilities rather than risks.

AD noted that the worst case results are based on load cases 2, 7 and 8 adding that probabilities in the region on 10^{-6} is the broadly acceptable region according to the Health and Safety at Work Act 1974. AD noted that his initial conclusion is that any of the settings would probably be ok, but there is a significant difference, 2 to 3 orders of magnitude, between the current and proposed settings.

JD asked who needs to be assured that it is acceptable for any changes to be made. MK noted that it is DNOs who need to understand ESQCR, EaWR[1] and HaSaWA[2] compliance.

AD suggested that, to minimise increase and maximise stability, option 2 would be his recommendation. ML noted that individual risk falls on the DNOs whereas the auto reclose risk falls on the plant owner. AD noted that these results are based on PV control; plant with PF control can have any setting because they will not remain stable. ML noted that in Scotland, pretty much all of SSE's new connections have voltage control capability and that there is a general trend towards wider deployment of PV control to maximise the capacity of the networks.

WH asked whether the tests take into account the different relay types and any internal settings. AD noted that there may be an internal time delay but this was not altered.

AD noted that these figures relate directly to the number of generators connected, if more generators connect then these numbers will increase proportionally as such the risk is proportional to number of connections. MK noted that there are a number of qualifications needed to say how this is overstating the effects.

ML asked how many generators National Grid are contracting with for Frequency Response, querying whether this has an impact. GS noted that National Grid can always specify that the providers have no adverse interaction with RoCoF.

AD noted that, in his experience, vector shift is quite insensitive and could change the results but there are no statistics on non-detected island conditions relating to Vector Shift techniques.

JD suggested it may be useful to have 1 setting option saying vector shift with 6 and 10 options, to establish the size of the NDZ to act as a comparison. AH noted that the relevance depends on the proposal, as if generators are required to change RoCoF settings now, then they would not revisiting a year later asking for Vector shift changes. GS noted that it is unlikely the same customers would be visited twice, as generators should have RoCoF or Vector Shift.

GS noted that the workgroup have committed to make a recommendation for 5-50MW, but questions on overall stability of system given the generation mix, is part of the next phase.

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[1] Electricity at Work Regulations
[2] Health and Safety at Work Act

The workgroup discussed the RfG requirements for users to be able to withstand frequency changes. ML noted that the decision for RfG is not part of this workgroup; it is on National Grid as System Operator. GS agreed in theory, but noted that part of the decision will be subject to National Regulator Approval and will take place in forums such as this.

MK suggested that as the absolute risk presented by either $0.5Hzs^{-1}$ and $1Hzs^{-1}$ is very small, ie the effective difference is marginal, there could be strong support for a setting of 1Hzs

JH suggested that to make a decision it is necessary to compare the cost of human life and the level of risk against the costs of National Grid mitigating the risk or the national cost of black outs. GS suggested that the system costs start at £30million but there is also a national reputational and inward investment risk to be considered.

Feedback from workshop.

RJ noted that the questions and comments from the workshop were captured in the feedback document that was circulated in advance of the meeting.

ML noted that in London one attendee had suggested producing a pamphlet highlighting the bigger picture and reasons why these changes are necessary. The workgroup thought that were merits of this. RJ added that Zoltan Zavody from RenewableUK had also suggested speaking at their annual conference.

MK suggested turning the feedback document into a publishable Q&A for circulation to all the attendees. This was added to the action log.

Workgroup Report

ML noted that there is a meeting about G59 on 30 May and it would be useful to have a view from National Grid on their recommendations by that time. MK noted that he is inclined to hold back on submitting G59 for decision to avoid having too many changes for customers.

The workgroup discussed the document and text changes required, questioned whether it was appropriate to delay G59 or whether these changes can be done removing protection settings from G59 and rely on the fact that the settings are duplicated in the D Code. This would then mean G59 could be published independent of the Frequency Resilience work, and the outcome of RoCoF deliberations could be updated in the D Code. ML noted that he is happy to wait a couple of months on G59 if it means all changes, including stability tests, will be done at the same time. ML added that if changes to stability test are not made then there could be manufacturers making plant with withstand at that level and not actually reaching the 1Hz/s GS suggested this may be acceptable if it is going to be revisited later

Feedback from EirGrid and SONI GCRP.

JM explained that in Ireland the Connection Conditions are automatically applied retrospectively, but there has been a modification proposed so that in NI the RoCoF changes do not apply retrospectively. The ROI regulator , CER, has brought in a consultant, to help look at the impacts of retrospectivity on Generators.

JM noted that there was a need to mobilise a technical assessment of generators in Ireland now have to see whether each generator is able to withstand a rate of change of $1Hzs^{-1}$at a cost of around €250,000 per plant assessment. JM noted that they are expecting to see a consultation from CER around the end of May.

JM noted that, in parallel, Eirgrid and SONI have published papers to look at $1Hzs^{-1}$ and loss of largest infeed adding that the key issue is if the East West Interconnector trips when importing 500MW. If this occurs there is a high risk of cascade tripping on high wind, low demand days. In ROI the system is restricted to operate with no more than 50% asynchronous plant, but that a RoCoF protection change is one of the measures required to increase this to 75% if these technical issues are solved adding that the rules for new plant are still being discussed.

JM suggested that in ROI it is unnecessary for all generators to meet a $1Hzs^{-1}$ withstand requirement and that peaking plant should be excluded as this will not be running in the middle of the night in high wind conditions. JD suggested that in a different operating environment, the System Operator could constrain off low RoCoF withstand plant, and keep on plant that will withstand high RoCoF.

JM agreed to circulate the Irish consultation when it is published.

Information Gathering

GS highlighted that, so far, most of the useful information has come from WPD. This information suggested that fewer generators had RoCoF protection than had been presumed in AD's assessment, and that it may be possible to discount RoCoF risks in some circumstances prior to any protection changes.