Summary of Meeting and Actions

Meeting Name	Frequency Response Working Group
Meeting No.	12
Date of Meeting	Friday, 13th August 2010
Time	10:00am – 3:00pm
Venue	Room C3-1, National Grid House, Warwick

This note outlines the key action points from the twelfth meeting of the Frequency Response Working Group.

1) Introduction/apologies for Absence

Apologies were received from Richard Coates (Ofgem) Mick Chowns (RWE), Mark Baker (Scottish Power), Raoul Thulin (RWE), John Welsh (Scottish Power Systems) and John Morris EDF Energy.

2) Minutes from Previous Meeting/Outstanding actions

The draft minutes of the Grid Code/BSSG Frequency Response Working Group meeting held on 8th July 2010 were approved and will be accessible from the National Grid Code Website.

The group were informed Richard Coates from Ofgem will not be attending any further meetings. Dan Jerwood from GDF Suez had also informed National Grid he will not be attending this Working Group any longer and plans to provide a replacement.

An outstanding action from the previous meeting was to consider how payment mechanism for system inertia could be enforced. AJ advised until further information is obtained on wind generation providing inertia, this action should not be closed.

Action: All

The question was raised whether Balancing Mechanism action had been issued to wind generation. AJ advised wind had been tested but had not been used in a live situation. MA identified a number of points in terms of payment mechanism which he thought were unclear, ie What the payment scheme is trying to achieve and how would it be paid for. Furthermore how would National Grid determine the volume in relation to the payment scheme?

It was stated providing inertia would be a mandatory requirement with machines being able to be selected and deselected required. The group discussed whether this requirement should be paid for; several members had identified other mandatory requirements within the Grid Code that were not paid for, such as power systems stabilisers and fault ride through.

TI updated the group on the SQSS review and informed there were two consultations due to close shortly; one on the fundamental review of SQSS looking at the implications of wind generation and the other on charging mechanisms for the increased reserve holdind cost resulting from large nuclear plants. In addition National Grid had sent a report to Ofgem on increased largest loss of 1800MW machines and was expecting a decision towards the end of the year. The group discussed whether Ofgem would adopt a more targeted cost approach or a socialised costs approach for these new types of generators.

3) System Inertia

AJ provided a presentation on system inertia and some background to why it is necessary in the management of frequency. It was advised that the background to the issues of system inertia had been described in earlier presentations which are available on the National Grid website. KA to upload the latest presentation on the National Grid website.

Action: KA

AJ presented a number of slides showing how a synchronous generator contributed additional short term power to the system immediately following the loss of a generating unit, through the energy stored in the rotating mass of the turbine and generator. He went on to say that renewable generation technologies which are decoupled from the prime mover (e.g. via a Power Electronic Converter) are insensitive to changes in system frequency. This prevents the short term injection of active power to the network; as a consequence the increased rate of change of system frequency/minimum frequency would be reached before recovery by the action of primary response. AJ advised that based on the volumes of renewable generation and HVDC connections expected over the next 10 years, this will be a major problem unless corrective measures are put in place.

AJ discussed the high level proposals for the provision of synthetic inertia to be provided by Generators which do not naturally provide this capability. It was advised that such a high level requirement would be similar to that of a synchronous machine but would be activated by a control system based on a change in frequency. This was on the basis that for small changes in frequency (e.g. for a generation loss of say 300MW) then the short term injection of active power would be less than that required for a large change in frequency such as an 1800MW loss. AJ confirmed that the short term injection in active power would be required in 200ms followed by an exponential decay which would be longer than about 10 seconds. This being aligned to the delivery of Primary Response.

Further study work had been completed using two tools, these being a spread sheet and full dynamic model in Digsilent Power Factory. AJ advised that good agreement had been obtained between the two tools which where shown during the presentation and also showed the effect of on rate of change of system frequency for generation losses of a different size. AJ advised that the control system was likely to rely on a df/dt function some form of filtering would be required within the proposals, as df/dt by its very nature is a noise amplifying process. AJ also thanked SW for his help in running some of the studies.

It was noted that there was ongoing dialogue with wind turbine manufacturers with regard to these proposals. Based on the current feedback received to date, the ability for a wind farm to provide a inertial capability was not a major issue. However AJ advised that when the wind turbines operate below rated output, they require a recovery period, which is dependant upon wind speed. AJ advised that there can be cases, particularly when the wind turbine is operating just below rated power output causing the recovery period to be quite large. In addition the post fault power output can drop as low as 80% of the prefault power, with the recovery period taking up to 40 seconds after the additional power injection has been provided.

The effect of this recovery period can result in a double dip, under worst case conditions the frequency could drop below 48Hz. One solution to this problem was thought to be that the wind speed across the country at any one time would be variable, such that each wind farm would see different wind speeds. Therefore minimising the effect of the recovery period. AJ advised that unfortunately this was not the case and showed some results which demonstrated critial parts of the day, where wind speeds could be fairly constant. AJ advised that at lower wind speeds the recovery period is not so severe and could be managed more easily. AJ went on to explain why he believed this issue was arising but advised further understanding and dialogue would be required with the manufacturers. SC questioned why the recovery period was larger than the period of over production. AJ advised that he would confirm.

Action: AJ

AJ advised that all studies and results rely on the fact that no prefault curtailment is required and that when the wind turbines operate at or above rated wind speed no recovery period is required. AJ advised that further dialogue and discussions would be held with the manufacturers to see what mitigation measures could be introduced to minimise the impact of the large recovery period. At the present time the thinking is that the facility is only likely to be required for plant operating in limited frequency sensitive mode of operation. AJ advised that there maybe a need to move away from this but this would depend upon further study work and discussions with manufacturers.

The summary of the high level proposals was then discussed. FL advised that plants which currently have to meet the requirement should not be restricted to Figure 1. AJ advised that he would amend the drafting. AJ to amend drafting for Synchronous machines.

Action: AJ

A general action was issued to all members to comment on the high level proposals.

Action: All

AJ advised that it may be difficult to develop firm proposals for the September GCRP as further input was required from the manufacturers. In response GP stated that a lot of good work had been completed but the GCRP would want to know what additional time was required. AJ advised this would be difficult as National Grid would be dependant upon third pary information but stated that he would issue a report to the September GCRP stating the work that had been completed and the outstanding issues. AJ to provide report to the GCRP advising of current progress and outstanding issues.

Action: AJ

4) Frequency Response Option Development

MA discussed with the group that he believed that two options may need to be presented at the next GCRP panel meeting, one option would be National Grid's preferred approach (A), with mandatory frequency obligations and the other (B) would be up to the industry reps to develop and may not include mandatory frequency provisions.

Option A would include a Grid Code Obligation based on National Grids requirement to maintain system frequency as captured in the transmission licence. As previously mentioned National Grid does not have a method itself in maintaining system frequency without the assistance from third parties. Therefore it could not ensure volume availability at any given time. To overcome the issue National Grid stated that obligations must be placed on generators within the Grid Code to ensure frequency response capability and availability. In this way National Grid would meet its obligations without the risk of uncertainty through the generators.

The counter view to option B as RT previously mentioned: if there was no obligation on the generators consequently the market would provide as long as there were market signals and the market price was there to do so. This characteristic is inherent in the current energy market. MA concurred with this and highlighted that National Grid does not have obligations in the energy market to provide energy as opposed to providing frequency response. There was a possibility that National Grid could lose its license if this was not provided. It was noted this option did not eliminate the risk of uncertainty and as consequence National Grid could not meet its security of supply standards.

As an alternative approach the members could opt to relax the Licence obligation. In this way National Grid would do all reasonable endeavours to ensure sufficient volumes of frequency response availability on the day. However during certain periods it will lead to high frequency deviation and offset demand. MA conveyed for these reasons Option A would include a Grid Code obligation.

CP stated even if there is a defined term requirement of (10,10,10) generators with capability could put in less such as (9,9,9) or more (12,12,12). MA stated within Option A there were further options which took account whether generators could self provide or the possibility of frequency response being met through contracts with other generators. The group identified if contracts were to be used they would have to include capability and delivery of response. A member recommended that contracts would also have to incorporate generators maintenance cost for providing the required response; without it some may not be willing to participate.

The benefit of this method will allow the generators the ability to carry out a cost benefit analysis and determine whether the contracting out the frequency response would be more desirable than providing the response yourself, ultimately this would be up to the generator. SC insisted there needs to be more detail within this option; to stop all generators being contracted out reducing risk of over exposure. He also stated that some technology type may find this option more desirable than others especially if they are not able to deliver frequency response from there own unit.

It became apparent that some generators may not be running on the day therefore this option would need to include provisions to ensure availability/delivery as well as capability. WH suggested that for those generators who could not meet the standard obligations, that an alternative obligation should be defined. A member responded that providers that cannot supply the full required response levels could nominate plant that could over provide response i.e (15,15,15) to compensate. Consequently, at the time of connection the provider would have state which plant had to run simultaneously to ensure sufficient availability. MA believed this method would benefit portfolio players as opposed to single units.

CH believed for investment purposes it was important to understand what the costs involved in not meeting requirement would be and whether the associated risks were limited or unlimited. MA suggested that if a FR market was established, the market would determine the value of Frequency Response, depending on availability. CH insisted that as long as there were appropriate market signals and sufficient information from National Grid to say what is required on the day for system needs, he would be happy to bid into the market.

The group agreed with a tradable option there were efficiency issues, the idea of shutting plants down to put on responsive plants could be questioned. CP supported this and recognised that having plants on at times where it was not required was ineffective and would inherently increase costs.

An approach was discussed that is similar to how black start provision is contracted. Generators will not be obligated to provide freq response but contractual arrangements will be developed on a bilateral basis. GP agreed to develop a paper to communicate how such a model may operate.

Action: GP

A member wanted to understand what should happen if the contracted response arrangement fails to deliver? SC believed that responsive units should be made to run, but CP insisted from an environmental perspective and cost benefit, thermal plant should not be forced to run superseding low carbon technology. SC stated having the capability and not running was inefficient as a provider would have incurred all the capital costs to ensure his plant was capable. It was debated whether day ahead reporting by National Grid could make things easier when coordinating plants onto the system. MA stated National Grid could only advise what plants would be available on the system until an hour ahead of real time. Therefore this was not possible.

It was considered whether there needs to be a defined minimum requirement. With this approach, units will only be paid for what they supply. The minimum requirement would be worked out by National Grids needs divided by the number of units available at the time. AJ advised the group, future studies revealed a significant increase in units on the system which is expected to increase by 2030. Therefore it was important to understand what percentage of plants needs to be responsive going forward. SC pointed out his minimum requirement would be based on the worst case scenario. A member stated if National Grid decides to adopt a socialised cost through minimum requirements this would favour larger plants, allowing them to pick and choose. Furthermore new players will be able to enter the market increasing competition and as such some players will opt out.

The Group discussed whilst demand side capability has a large potential to provide response, there are issues associated with testing and ensuring such provision.

MA to write up pros and cons for Option A and its sub option and circulate to the group.

Action: MA

MA then presented Option B to include onsite capability supported by other technologies of choice for discussion. He stated that option will be easy to test, providers will be able to meet requirements without difficulty however they may not be able to take full advantage of a full market. This option would remove some the issues discussed in option A i.e socialised costs. MA invited comments from the group and FL responded that this option was too restricted. A member pointed out the option was really a sub option of option A.

TI to speak to RT to suggest that an auctions model is developed.

Action: TI

The auction process would include National Grid publishing requirements a day ahead and providers would then have to bid in National Grid would then arrange generators in price order, finally choosing the generators that are to provide the response the next day. In this way National Grid will have the ability to choose as much response is needed on the day. MA stated these contracts will have similar characteristics to the FFR contracts. Providers will have the choice of trading with no capability with a market base approach or with capability were you would have an obligation to bid onto the market.

5) AOB

MA presented the group with table of future response requirements for primary secondary and high response levels expected for 2009/10 to 2025/26. He explained that he had completed a cost benefit analysis and noticed that there were significant changes of increase in primary, secondary response requirement apart from High when the 1800mw machines become live. FL questioned why the high frequency requirement had not changed. MA explained that high frequencies were covering largest demand loss therefore it did not change.

[Malcolm please add more]

The question was raised whether suppliers should provide Primary/Secondary and High response requirements separately in the future. This is to be discussed further at the next meeting? WH requested all members to speak to their manufactures to see if this was possible.

Action: All

TI informed the group that the CUSC Panel had stated that DEC's recent consultation on smart metering could have impact on the group's work, in particular to some of the models that were being discussed. He also informed that therefore the CUSC Panel had requested for the groups TOR to incorporate smart meters and future technology. Several members agreed that having this change would have significant increases on the groups work and may risk delivery timescales. TI to circulate the smart metering consultation around the group so a work forward could be determined.

Action: TI

6) Next Meeting

The next working group is scheduled for the 10th September at Warwick House starting 10am.

Appendix 1 – Working Group Attendance

Members Present:

Tom Ireland	TI	Working Group Chairperson
Kabir Ali	KA	Technical Secretary
Antony Johnson	AJ	National Grid
Malcolm Arthur	MA	National Grid
William Hung	WH	National Grid
Stephen Curtis	SC	National Grid
Stewart Whyte	WH	National Grid
Chris Hastings	CH	Scottish-Southern
Francois Luciani	FL	EDF Energy
Bob Nicholls	BN	E.ON UK
Guy Phillips	GP	E.ON UK
Chris Proudfoot	CP	Centrica

Apologies:

Richard Coates	RC	Ofgem
Mike Chowns	MC	RWE
Mark Baker	MB	Scottish Power
Raoul Thulin	RT	RWE
John Welsh	JW	Scottish Power (DNO Representative)
Dan Jerwood	DJ	GDF SUEZ Energy UK
John Morris	JM	EDF Energy