Summary of Meeting and Actions

Meeting Name	Frequency Response Working Group
Meeting No.	13
Date of Meeting	Friday, 10th September 2010
Time	10:00am – 3:00pm
Venue	Room C3.8, National Grid House, Warwick

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

1) Introductions, Minutes and Apologies

Apologies were received from Francois Luciani (EDF Energy), John Welsh (Scottish Power Systems), Raoul Thulin (RWE), Guy Phillips (E.ON UK) and John Morris (EDF Energy).

2) Actions from Meeting 12

The draft minutes of the Grid Code/BSSG Frequency Response Working Group meeting 12 held on 13th August 2010 were approved and will be accessible from the National Grid Codes Website.

Action: TD

The group noted a few of the outstanding actions from meeting 12.

Contact RT and GP to request that the market models they are developing are drafted prior to the next meeting to allow them to be discussed.

Action: MA

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

Action: All

3) System Inertia

AJ commented on the System Inertia actions raised in meeting 12 and updated the group on their progress. AJ also informed the group that he had submitted a paper to the September GCRP, titled '*Future Frequency Response Services*' which covers the technical issues raised in this working group, an overview of the work completed to date and future issues that need to be resolved going forward. This paper is now available on the National Grid website which will be submitted to the September GCRP.

AJ updated the group on System Inertia as well as providing the background of the work completed to date. It was noted that all the previous presentations from AJ are available on the National Grid website and this presentation will be uploaded following the meeting.

Action: TD

AJ summarised the most recent work completed on various Control Schemes which could be developed to implement a synthetic inertia capability (Control 1 & Control 2). Both of which would be based on a df/dt requirements. These two schemes are detailed below.

Control 1 - Power injection based on initial df/dt only (slide 5)
It was explained that for a specific change in df/dt there is a specific increase in active power required. Once the initial active power has been injected over and above the pre

disturbance level, the active power will decay linearly to the pre disturbance level over a 10 second period. . The graph showed indicative numbers for different rates of change of system frequency, however the key point is that this control system is not continually acting ie once the initial rate of Change of System has been detected, the increase in active power above the pre-disturbed level will ramp down linearly to the pre-disturbed level some 10 seconds later, irrespective of any other system change. AJ noted that as the system was not continually acting over the 10 second recovery period, (following the initial injection of active power in response to a change in df/dt) there were some concerns of over the ability of the control system to react to subsequent changes in system frequency should another event occur.

Control 2 - Power injection based on full df/dt control pre/post fault (slide 9)

In contrast to the one-shot approach above, this system is continually acting. This is a fully acting control system in which the additional active power supplied by the Wind Turbine over and above pre-disturbance level is continually controlled being dependant upon the rate of change of frequency. In this case, the initial rate of change of frequency will be high, resulting in a high injection of active power, and as time progresses, governor action together with other control measures will slow the rate of change of system frequency resulting in a reduction in the injection of active power.

Confusion arose around the term ‘pnom’ on the control scheme graphs, AJ clarified that it was relating to the prevailing power level (based on the wind speed) prior to the disturbance in frequency and agreed to change the term ‘pnom’ to clarify.

Action: AJ

AJ presented his key conclusion from recent study work which demonstrated that there is an inherent link between the volumes and more importantly the speed of delivery of the primary response required, against the requirement for the volume of synthetic inertia. AJ advised that for a 1320MW loss, a requirement and settings for a synthetic inertia capability could be developed. This was on the basis of a minimum system load of 25GW, no contracted demand tripping, frequency response delivery in 10 seconds and a typical overall system inertia constant of 6.18MWs/MVA.

AJ advised however, that due to the inherent link between the speed of delivery of primary response and synthetic inertia, it was more difficult to establish the levels of synthetic inertia for an 1800MW loss.

AJ advised that under an 1800MW loss scenario, the same principles to determine the volume of synthetic inertia was used as in the 1320MW case. In this scenario, a minimum system demand of 25GW is considered, with an 1800MW loss, no contracted demand tripping, frequency response being delivered within 10 seconds as per the current Grid Code requirement and an overall system inertia constant of 6.18MWs/MVA. It is first necessary to assume there is no wind generation on the system (ie light wind conditions) with all plant being synchronous. The same study is repeated, but in this case based solely on wind generation (allowing for a minor volume of synchronous plant to cater for the largest loss and some additional synchronous plant to provide primary response). In this latter wind case, the volume of synthetic inertia is increased to obtain the same results as for a purely synchronous case. However as part of this work, it was identified that under the conditions described above, with purely synchronous plant, the system could not be secured unless the speed of delivery of primary response was increased, or alternative methods such as contracted demand tripping are introduced. It was however noted that under a full wind scenario, the system could be secured but large volumes of synthetic inertia would be required, in this case however, the synthetic inertia contribution required would need to be far higher than that provided by the synchronous generation equivalent.

Thus, AJ advised that until the minimum requirements in terms of volume and delivery of primary response have been defined for an 1800MW loss, using synchronous generation only, it is not possible to finalise the inertia requirements for wind generation. The final element of this work would then be to review the rate of change of frequency protection settings for Embedded Generation.

It was asked how far from reality is this most recent study and it was explained that it is based on the current Grid Code requirements and does not take into account any non-technical aspects such as contractual demand tripping . In response to one question, AJ advised that he would re-run the studies to establish the variability in results if changes were introduced to the volume of deload or contracted demand tripping was used.

Action AJ

One working group member noted that it appeared we have not established the most basic technical requirements that the Grid Code would have to provide under a scenario where the largest loss is 1800MW. This technical basis needs to be devoid of any economic or market aspects so that it is known at the most basic technical level that the system is securable.

AJ also pointed out that under an 1800MW loss scenario, the rate of change of system frequency will increase substantially beyond current levels. This will have an impact on the protection settings for Embedded Generation. In response, SC questioned whether there where any other system issues which could be affected by Rate of Change of System Frequency. AJ had a vague recollection that there may be an issue with valves on the Gas Transmission System supplying gas fired power stations but advised he would confirm and find out.

Action AJ

Following discussion from the group it was concluded the group will aim to give an update to the September GCRP of progress to date and write a paper for submission to the November GCRP with next steps and issues to go forward with such as system needs, Grid Code obligations, other parties that need to be involved and what the market could look like.

4) Separation of Frequency Response Products

BS presented a Cost Benefit Analysis of National Grid being able to select the different response products, primary (P), secondary (S) and high (H) separately. He described that National Grid currently is only able to procure mandatory response services as a block e.g. can only procure P and H response, or P, S and H together. This leads to an excess of certain products being procured.

It was noted by the working group that it may be possible to split positive and negative frequency response, but splitting out P and S would be very difficult (the group also noted complexity in splitting out the timescales of delivery of P and S), although splitting the low response products (P & S) from H was not perceived as being overly complex. Due to the cost of separating the products, separate P and S services that are split from H may be priced to account for the extra cost of splitting the products.

MC described the use of an Integrated Load Controller (ILC) which provides the capability of submitting a defined response matrix; it was thought that something similar would be required to separate H from P & S. ILC maybe able to split out the various response products, but it was also noted that it is already a fairly complex control.

The group discussed that it could be possible to develop a product that would split out the response products and provide each separately as an ancillary service however, the R&D cost is a barrier to entry. There is also some concern that the initial investment cost to develop such a system may be difficult to recover. It was asked of the group if they believed it was possible, at some point in the future, to place an obligation on generation to provide P, S and H as separate products.

The group noted that in the future, separate products may become a requirement however, a User should be able to submit any mixture of services from all individual products to a complete combination. Most current generators do not have controllers capable of providing these response products separately and until there is an incentive to invest in the technology, most Users would not be able to meet a requirement to provide all products separately.

It was noted that if every generator provided the individual products and responded as required under the Grid Code, it is possible to assume that it would change the system dynamics. Frequency could fluctuate more, steady state control could be affected and any benefits of delivering the products alongside each other could be lost.

A change to the Grid Code to allow a mixture of products (e.g. PSH, PS, H) to be supplied was discussed which would leave it to the User to decide the commercial choice. The group seemed supportive of this idea following further work and also noted that it might be most logical to start with splitting the positive and negative frequencies.

5) Frequency Response Option Development

a. National Grid Option

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 primary option is offsite capability transfer of the obligations that a generator has to provide frequency response. Generators will be able to transfer their obligation to other users (generation or demand) that provide frequency response. The question was raised that it needs to be determined whether or not an obligation can be placed on a user that cannot meet that obligation without trading it away.

A subset option, would be onsite capability transfer only, in which a generator does not need to self provide but can use additional on site equipment to meet the obligation, e.g. batteries.

The issue of cost was discussed. Whether the cost is targeted or socialised is probably not within the remit of this group, however it was noted that it is important to discuss cost generally rather than how it is covered. It was argued that there is an aspect of targeted costs within the proposal as otherwise everyone would offload their responsibilities because any cost of doing so would be socialised.

It was also noted that it is possible that the market may sort the prices out themselves. If a User participates, they may have a chance to make some profit whereas if they are able to participate and choose not to they will miss out on any potential profit in the market and pay increased BSUoS costs.

One member commented that frequency based metering is going to be required to show what has been traded and received by the different parties. The group noted that there would likely be an additional cost as a result of this.

National Grid will write up a proposal for this option, taking the above points into account, to be submitted to the GCRP.

Action: MA

b. Industry Options

The industry options are being progressed by RT and GP. RT is to develop a strawman based on an auction approach and GP is to develop a market based strawman on similar principals to the current black start service. These papers will be put together for submission to the GCRP to describe each option.

Action: RT & GP

6) AOB

No other business was discussed by the working group members.

7) Date of Next Meeting

Update to the Working Group following the GCRP along with a holding date for next meeting.

Appendix 1 – Working Group Attendance

Members Present:

Chris Shanley	CS	Working Group Chair
Thomas Derry	TD	Technical Secretary
Antony Johnson	AJ	National Grid
Malcolm Arthur	MA	National Grid
William Hung	WH	National Grid
Stephen Curtis	SC	National Grid
Ben Smith	BS	National Grid
Chris Hastings	CH	Scottish-Southern
Mick Chowns	MC	RWE
Bob Nicholls	BN	E.ON UK
Chris Proudfoot	CP	Centrica
Chris Harrison	CHn	EDF Energy

Apologies:

Raoul Thulin	RT	RWE
John Welsh	JW	Scottish Power (DNO Representative)
Francois Luciani	FL	EDF Energy
John Morris	JM	EDF Energy
Guy Phillips	GP	E.ON UK