Stage 01: Workgroup Report

Grid Code

GC022 - Frequency Response

What stage is this document at?

01	Workgroup Report
02	Industry Consultation
03	Report to the Authority

This Workgroup investigated the technical requirements and commercial mechanisms applicable to the provision of frequency response, given the current generation mix and the anticipated changes in generation technologies.

This document contains the findings of the Workgroup which formed on 22 October 2008 and concluded on 05 November 2012.

Published on: **09 January 2013**

The Workgroup recommends:

That the technical recommendations are taken forward for Industry Consultation as they better facilitate the applicable objectives (i) and (iii), and that the commercial recommendations are further developed by the Balancing Services Standing Group (BSSG) and Commercial Balancing Services Group (CBSG).

High Impact:

New asynchronous generators and interconnectors required to provide frequency response, System Operator

Medium Impact:

None identified

Low Impact:

None identified

Contents

Any Questions?

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Frequency Response Workgroup

About this document

This Workgroup Report outlines the discussions and recommendations of the Frequency Response Workgroup.

Document Control

Version	Date	Author	Change Reference
0.1	25 December 2012	National Grid	Draft Workgroup Report
1.0	09 January 2013	National Grid	Final Workgroup Report

1 Executive Summary

1.1 Summary

1.1.1 The Frequency Response Workgroup was established to examine and make recommendations for the future provision of frequency response, taking account of system security requirements and with the aim of delivering an efficient solution for the industry as a whole.

1.1.2 Since the Workgroup was established in 2008, there have been 22 Workgroup meetings. Over that time a number of commercial arrangements and technical requirements have been discussed and analysed by the Workgroup.

1.1.3 To assess issues associated with meeting the requirements for frequency response arising from significant changes to the generation background, a Frequency Response Technical Subgroup (FRTSG) was established in November 2010. The aim of the FRTSG was to complement and extend the technical work initiated by Frequency Response Workgroup (a joint BSSG and GCRP Workgroup), and in particular investigate issues such as the ability of variable speed wind turbines to contribute to system inertia against a likely future generation background.

1.1.4 Alongside the work undertaken by the FRTSG, the Frequency Response Workgroup developed a number of high level commercial arrangements to improve the provision of frequency response services.

1.2 Workgroup Recommendation

1.2.1 The Workgroup recommends that:

(i) A 5 second frequency response requirement is developed for asynchronous generators along with improving the clarity of the frequency response commencement and delivery profile from synchronous generating plant. This work should continue under the Grid Code and it is proposed that an Industry Consultation is developed and brought to the March 2013 Grid Code Review Panel.

(ii) The existing CUSC-based remuneration mechanism for mandatory frequency response is developed to accommodate the rapid response service from asynchronous plant and the additional clarity around ramping. This development should be undertaken by the Balancing Services Standing Group (BSSG) and Commercial Balancing Services Group (CBSG).

(iii) The existing commercial frequency response arrangements are further developed to provide a weekly tender and accommodate a rapid frequency response product that will be available to both generation (both asynchronous and synchronous) and demand providers. This development should be undertaken by the Balancing Services Standing Group (BSSG) and Commercial Balancing Services Group (CBSG).

2 Purpose & Scope of Workgroup

2.1 Background

2.1.1 At the May 2008 Grid Code Review Panel (GCRP), National Grid presented paper pp08/20 which proposed that a Workgroup was established to examine and make recommendations for arrangements for the provision of frequency response, taking account of system needs and overall efficiency.

2.1.2 The GCRP agreed that a joint CUSC and Grid Code Workgroup should be established and, following the first Workgroup meeting on 22 October 2008, the Terms of Reference were approved by the GCRP. It was agreed that the Workgroup would report to the Balancing Services Standing Group (BSSG), a standing group under the CUSC.

2.1.3 The joint BSSG/Grid Code Workgroup would be tasked with reviewing the technical requirements and commercial mechanisms applicable to the provision of frequency response, given the current generation mix and the anticipated changes in generation technologies.

2.1.4 A copy of the Terms of Reference is available in Annex 1.

2.2 Scope

2.2.1 The Terms of Reference underwent a number of alterations over the time, agreed by the GCRP, that the Workgroup has been established. The scope of the Workgroup was:

(i) examine the appropriateness of the existing Grid Code obligations and commercial mechanism for frequency response to the current and predicted future generation mix – including offshore generation;

(ii) identify feasible options that will maintain the security of the National Electricity Transmission System following frequency deviations (inclusive of islanding scenarios), taking account of the characteristics of the current and next generation of power stations e.g. nuclear, supercritical coal, wind etc and the potential for demand management;

(iii) identify and quantify the advantages and disadvantages of each option;

(iv) identify all the impacts of each option on the Grid Code, CUSC and any other associated documents within the framework;

(v) agree and recommend a preferred option;

(vi) draft any text modifications necessary to implement the recommendation;

(vii) monitor the progress of the National Electricity Transmission System SQSS review and take into account any impact on the frequency reserve holding requirement arising from its recommendations.

(viii) consider frequency response provisions of any other comparable electricity networks worldwide

(Ix) Consider the interaction with the ongoing development of the European Network Codes.

Frequency Response Workgroup Meetings

M1 - 22 October 2008
M2 - 29 January 2009
M3 - 30 March 2009
M4 - 03 July 2009
M5 - 01 September 2009
M6 - 27 October 2009
M7 - 02 December 2009
M8 - 15 February 2010
M9 - 28 April 2010
M10 - 01 June 2010
M11 - 08 July 2010
M12 - 13 August 2010
M13 - 10 September 2010
M14 - 14 October 2010
M15 - 20 December 2010
M16 - 04 March 2011
M17 - 12 September 2011
M18 - 13 January 2012
M19 - 01 March 2012
M20 - 05 April 2012
M21 - 09 May 2012
M22 - 05 November 2012

Frequency Response Technical Subgroup Meetings

M1 - 15 November 2010
M2 - 03 December 2010
M3 - 13 January 2011
M4 - 28 March 2011
M5 - 05 August 2011
M6 - 13 October 2011
M7 - 07 November 2011

2.3 Timescales

2.3.1 It was originally agreed that the Workgroup would report its findings and recommendations to the November 2009 GCRP. As the issues around frequency response were investigated and studies conducted the original timeframe has been reviewed and agreed to allow further work to be undertaken.

2.3.2 It was agreed at the January 2012 GCRP that the Workgroup would report back to the November 2012 GCRP. This revised timescale was agreed to allow the Workgroup to conduct an industry consultation on the discussions and findings of the Workgroup to date.

2.3.3 The Workgroup conclusions were presented to the November 2012 GCRP and it was agreed that the final Workgroup Report would be submitted to the January 2013 GCRP.

2.4 Frequency Response Workgroup

2.4.1 Following agreement from the GCRP to establish the Frequency Response Workgroup in May 2008, the first Workgroup meeting was held on 22 October 2008.

2.4.2 Since the Workgroup was established in 2008, there have been 22 Workgroup meetings. Over that time a number of commercial arrangements and technical requirements have been discussed and analysed by the Workgroup.

2.4.3 Due to the wide ranging discussions that have taken place, the technical requirements and commercial arrangements each have their own chapter within this Workgroup Report.

2.5 Frequency Response Technical Subgroup

2.5.1 In September 2010, National Grid presented paper pp10/21 to the Grid Code Review Panel (GCRP) entitled “Future Frequency Response Services”. This paper[1] summarised the issues associated with meeting the requirements for frequency response arising from significant changes to the generation background.

2.5.2 In October 2010, the Frequency Response Workgroup discussed the establishment of a Frequency Response Technical Subgroup (FRTSG) which would develop recommendations to address the issues discussed in paper pp10/21 submitted to the GCRP.

2.5.3 In November 2010, the FRTSG was established to complement and extend the technical work initiated by Frequency Response Workgroup, and in particular investigate issues such as the ability of variable speed wind turbines to contribute to system inertia against a likely future generation background. The Terms of Reference for the FRTSG can be found in Annex 2.

2.5.4 The FRTSG had 7 meetings and during that time the Frequency Response Workgroup held limited meetings until the publication of the Technical Subgroup conclusions. The FRTSG published their conclusions in December 2011 and a copy of the report can be found in Annex 4.

[1] A copy of this paper can be found in Annex 3 of the Workgroup Consultation which is available at: http://www.nationalgrid.com/uk/Electricity/Codes/gridcode/consultationpapers/current/Frequency_Response/

3 Frequency Response Technical Subgroup Discussions

3.1 Introduction

3.1.1 This chapter contains a summary of the discussion, analysis and conclusions of the FRTSG.

3.1.2 The Terms of Reference for the FRTSG can be found in Annex 2 and copy of the Technical Subgroup Report can be found in Annex 4.

3.2 Background

3.2.1 A major element of this study work is to establish the effect on system frequency of the increasing volume of variable speed wind turbines and HVDC Converter technology. Whilst these issues are now well known, and set out in the ‘Future Frequency Response Requirements’ paper[2], it is worth briefly summarising the potential concerns.

3.2.2 Conventional synchronous generation which currently contributes to the majority of the Transmission System load is sensitive to changes in system frequency. In the event of the loss of a generating unit, the remaining synchronous plant will supply an injection of active power into the network through the stored energy in the rotating masses. This natural phenomena greatly assists in limiting the rate at which system frequency changes.

3.2.3 Unfortunately, variable speed wind turbines and other static devices which utilise power electronic converters such as HVDC converters are insensitive to frequency changes and therefore do not behave in the same way as synchronous machines resulting in a diminution in the system frequency. This issue is illustrated in Figure 1 below.

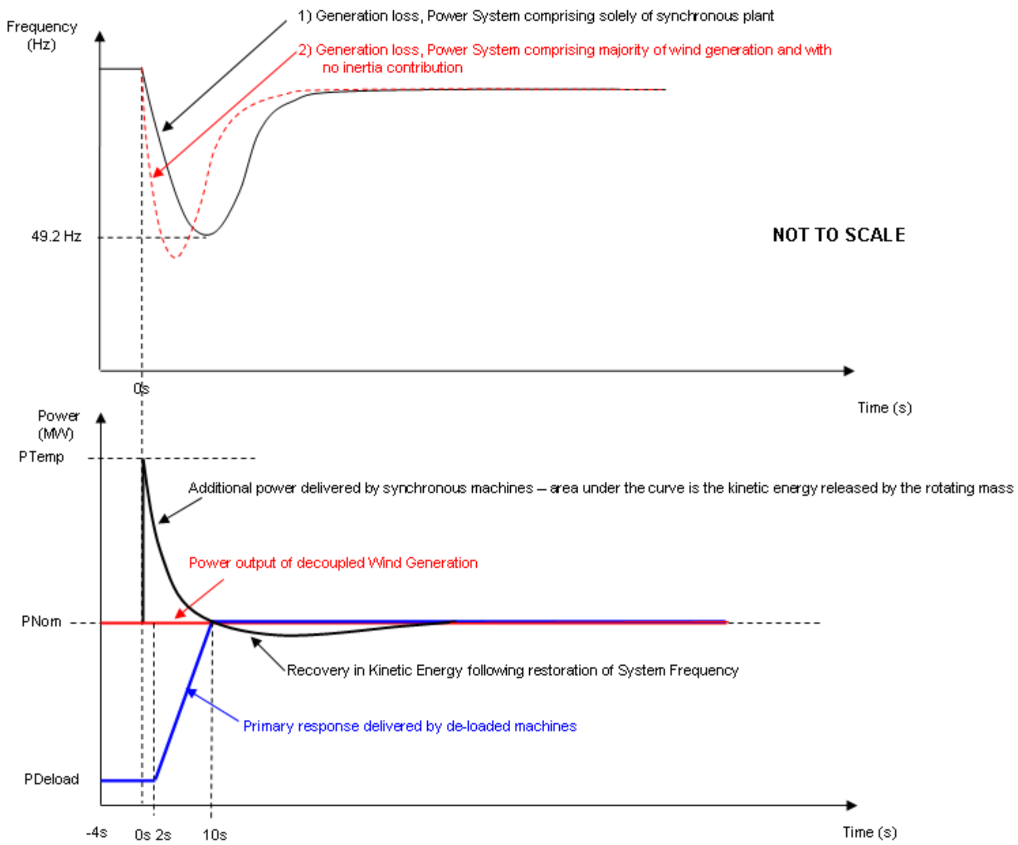

Figure 1: The effect of reduced system inertia on the management of a large infeed loss

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[2] A copy of this paper can be found in Annex 3 of the Workgroup Consultation which is available at:
http://www.nationalgrid.com/uk/Electricity/Codes/gridcode/consultationpapers/current/Frequency_Response/

3.2.4 As can be seen in the red curve of Figure 1, for the same generation loss, it is not possible to maintain the system frequency above 49.2Hz when a high volume of asynchronous generation is connected to the system and unable to contribute to system inertia. The reason for this is the lack of Active Power (shown by the red line) injected from the asynchronous generation as shown in the lower of the two graphs in Figure 1.

3.3 Initial Discussion

3.3.1 The discussions focussed on two approaches to managing large frequency deviations on systems where a lack of 'natural' inertia means that the system frequency may not be contained within statutory and technical limits.

3.3.2 The first approach considered was to investigate the option of equipping variable speed wind turbines and other asynchronous sources with a 'synthetic inertia' capability. This capability has the potential to improve frequency control without needing to curtail the power output of the wind turbine generating units prefault. This option was investigated at length and detailed discussions were held with a number of the major wind turbine manufacturers.

3.3.3 A number of manufacturers have indicated an ability to provide a synthetic inertia capability and have published papers and information on their capabilities - see references [1] – [4] in Annex 5. These controllers aim to inject power to the network in a similar way to that of a synchronous machine, but through controlled action.

3.3.4 As part of an effective control strategy, it is important to ensure sufficient active power is injected into the network to balance the loss of generation. Clearly too much active power injected into the network could result in temporary over frequencies occurring before governor action provides adequate downward regulation. For example, with a loss of generation of less than 300MW, only a small amount of active power would be required where as a larger injection would be required for the maximum loss of 1,800MW.

3.3.5 A good measure of the required level of active power injection can be obtained from a measure of the rate of change of system frequency (df/dt) (ie the smaller the value of df/dt the lower the initial injection of active power required).

3.3.6 National Grid modelled two controllers both using df/dt functionality. One was based on an initial injection and fixed decay based on the rate of change of system frequency. The second was based on a continuously acting df/dt controller which would operate throughout the entire disturbance, and in doing so regulating the active power injection to the network continuously. Based on the results, both controllers were able to inject sufficient active power to the network to ensure the maintenance of system frequency above Security and Quality of Supply Standards (SQSS) limits. These are described in more detail in Annex 5.

3.3.7 Whilst system studies confirmed that both controllers could be used as a basis to resolve the issue of retaining frequency standards, further discussion identified two critical issues. These being:

- df/dt controllers are noise amplifying and can, even with appropriate filtering, fail to operate in the appropriate manner, particularly where small time constants are involved; and

- the recovery period for wind turbines operating at just below rated wind speed can result in substantial reductions in their active power output, resulting in a system frequency collapse some 10 to 15 seconds after the initial generation loss.

3.3.8 With regard to the df/dt issue, National Grid held extensive discussions with manufactures to examine the df/dt controller and how it could be improved. National Grid amended their own models and identified that even with slower response times the controller could still aid frequency containment.

3.3.9 It was also suggested that the controller should not only rely on a df/dt input but should also incorporate a frequency trigger. Consideration was also given to a simple 'one-shot' control which would deliver a fixed volume of energy with a defined ramp and decay period when frequency reached a pre-defined setting.

3.3.10 A benefit of the 'one-shot' control is that it is less complex than a df/dt trigger. However, it wouldn't adapt to a specific frequency event after the initial frequency disturbance, potentially resulting in an uncontrolled response.

3.3.11 With regard to recovery periods, concerns were raised relating to the potential reduction in power output from wind turbines following the provision of increased active power output in response to a frequency fall.

3.3.12 A variable speed wind turbine relies on operating at the optimum power output for a given wind speed to extract the maximum available power from the wind. This is a complex non linear function and becomes a significant issue when the wind turbine is operating just below rated wind speed. In the event that the wind turbines are operating at just below their rated wind speed and activation of the synthetic inertia control is required, then once the additional active power has been injected into the network, the recovery period can result in a drop in power output of up to 30% of its pre fault output, resulting in a frequency collapse after the event.

3.3.13 Figure 2 below shows an illustrative frequency trace using a power injection equivalent to 10% of non-responsive wind generation, with a 10% loss of output from the same plant after 10 seconds.

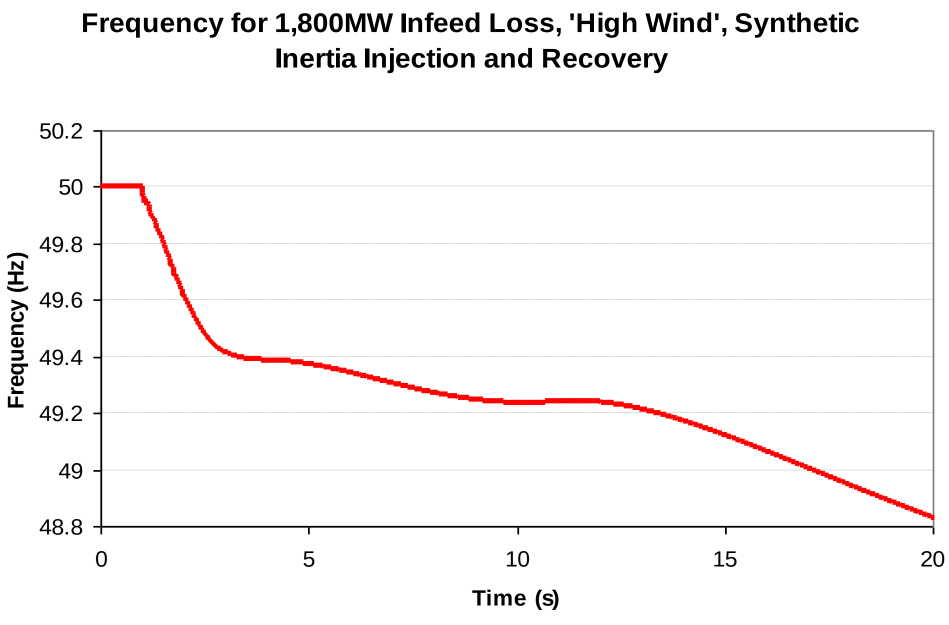


Figure 2: The effect of loss of active power output during the wind turbine 'recovery period'

3.3.14 In investigating this issue, a range of wind statistics were examined to determine the likelihood of a large volume of wind generation across the country operating at a similar wind speed. Data was also obtained to examine the effect of how wind speed varied within the wind farm.

3.3.15 The results of this analysis demonstrated that there was potentially a serious risk that a significant volume of geographically dispersed generation could be operating at a similar wind speed. The only guaranteed solution to this would be for the wind generation to be curtailed pre-fault, reducing the rate at which emission savings can be delivered.

3.3.16 An alternative approach to a synthetic inertia requirement would be to consider a method of rapidly injecting active power into the system following the loss of a generating unit by adopting a conventional proportional governor control.

3.3.17 This second approach was investigated using a response characteristic on frequency responsive wind generation that provided full primary frequency response within 5 seconds, being sustained for a further 25 seconds, rather than the current Grid Code requirement of delivery in 10 seconds and sustainable for a further 20 seconds.

3.3.18 The results of these studies demonstrated that the system frequency deviations could also be contained when ‘Fast Frequency Response’ was installed and that significant reductions in response requirements could also be achieved.

3.3.19 Discussions also highlighted concerns over the ability to deliver a synthetic inertia capability and conventional Primary Response from the same machines at the same time. It is therefore necessary to consider the likely generation patterns more carefully to check whether there is a sufficient amount of synthetic inertia capable plant which isn’t already required to manage system frequency in Primary and Secondary response timescales.

3.3.20 In assessing the materiality of the issue, it is also important to consider the proportion of the time where a synthetic inertia requirement may be needed to allow National Grid to meet the frequency containment requirements of the SQSS. Initial simulations highlighted that achieving frequency containment was significantly more challenging at transmission system demands of 35GW and less. A review of transmission system demands for 2008 to 2010 suggests that this represents approximately 50% of the time.

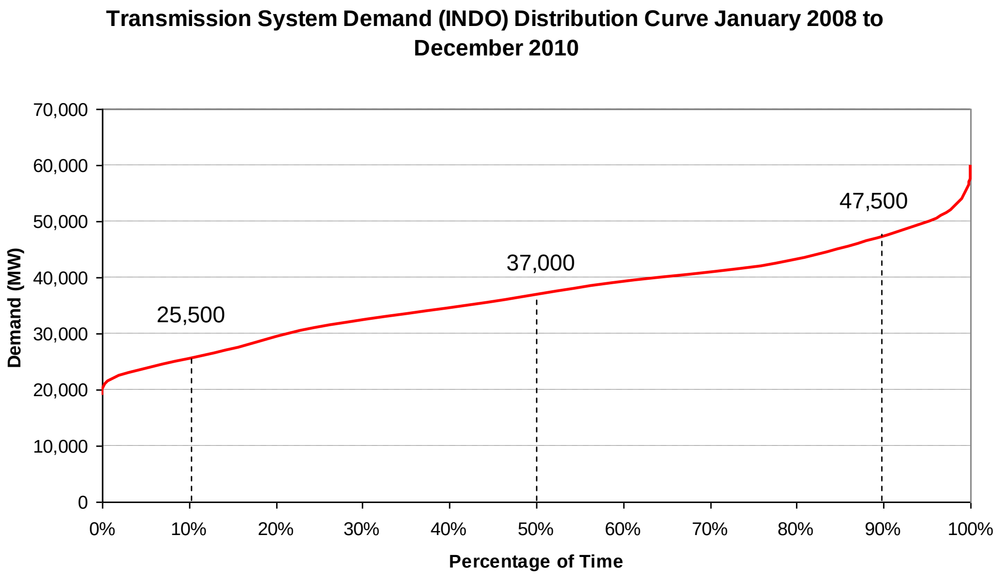


Figure 3: Transmission System Demand distribution curve

3.3.21 The next stage of analysis therefore needed to be based on clear demand and generation assumptions which are discussed in the full version of the Technical Subgroup Report (Annex 4).

3.4 Conclusions

3.4.1 In order to manage the Transmission System in the future and ensure system frequency can be managed to the criteria set out in the SQSS, there will be a requirement to mitigate the reduced contribution to system inertia from decoupled generation plants such as variable speed wind turbines and other static plant such as HVDC Converters.

3.4.2 The following conclusions were drawn from National Grid's simulations based on a 'Gone Green' generation scenario for the year 2020:

- A supplementary frequency control facility can deliver significant benefits in managing the 1,800MW and 1,320MW infeed risk at system demand levels of 35GW and below under all but "Low Wind" conditions.

- The measures needed to ensure compliance with the SQSS, and avoid impacting on system security, become more severe and more significant in volume as system demand, and the capacity of any synchronous generation meeting it, decreases;

- Additional low frequency relay triggered demand response was required as well as supplementary frequency control capability to achieve frequency containment at system demands of 20GW under 'High Wind' conditions;

- These factors suggest that both a supplementary frequency control capability and alternative actions will be required to ensure frequency containment can be achieved at demands of less than 25GW. Further alternative actions include:

- (1) Curtailment of the largest infeed loss; and

- (2) Additional balancing actions, such as:

- (2a) curtailment of interconnectors or inflexible plant;

- (2b) displacement using plant with additional response capability;

- (2c) fast acting low frequency relay triggered response; and

- (2d) addition of inertia, by 'low load operation' on synchronous generation for example.

3.4.3 It should be noted that the simulations were based on an interconnector position of 'float' (ie no import/export) and that any net interconnector import has the effect of displacing synchronous plant. There is currently 3.5 GW of interconnector capacity on the transmission system, a variability of 7GW. It should however be noted that the volume of interconnections to Great Britain may increase in the future.

3.4.4 A number of supplementary frequency control capability options were investigated, including a pure 'df/dt' driven fast acting control on un-curtailed asynchronous plant which is intended to mimic the inertia capability of a synchronous machine. This form of control provides an ideal solution, as it helps solve the frequency control problem without the need to curtail wind. However, there are a number of issues associated with it:

- any control system will incorporate a processing delay which needs to be limited to ensure the desired effect is achieved;

- Rate of Change of Frequency (RoCoF) as an input parameter is inherently noise amplifying leading to unpredictability of response;

- care needs to be taken not to extract too much energy from wind turbines as this can lead to an extended and detrimental recovery period, particularly at specific points on the wind turbine operating curve. This leads to some uncertainty over the volume and timescales of energy available; and

- discussions suggest that wind based Power Park Modules will find it difficult to deliver both a 'df/dt' driven fast acting control and Primary Response consecutively with the volumes required. This issue is critical as work to date suggests that both are required under most of the relevant system scenarios.

3.4.5 Alternative synthetic inertia controllers based on Rate of Change of Frequency, using fixed and variable volumes were investigated. It was demonstrated that these options provided a potential solution to the frequency containment problem, provided that the correct volumes and characteristics could be specified. These would need to be validated for the full range of possible future system conditions.

3.4.6 Finally, the option of using faster acting proportional frequency control was investigated by taking a conventional Primary Response characteristic and adapting it to deliver response within 5 seconds rather than 10. This characteristic was applied to wind generation which was already curtailed in order to provide conventional Primary Response within the simulations described in the Technical Subgroup Report.

3.4.7 This faster acting capability had the effect of reducing the Primary Response requirement and hence the need to curtail renewable generation significantly. A benefit of between 400MW and 950MW was observed in the simulations presented in the Technical Subgroup Report. If one assumes that this benefit applies for 10% of the year at an average of 500MW and response price of 30 £/MW/h, a benefit of £13m per year in balancing cost could be attributed to this capability. There would be an additional carbon benefit for the wind curtailment avoided.

3.4.8 Based on the analysis conducted, it has been concluded by the Technical Subgroup that the single change to response provision that would yield the most significant benefit is through the introduction of a fast primary frequency response capability applicable to all decoupled generation sources which do not naturally provide an inertial contribution.

3.4.9 Such generating plant should have the capability to provide 10% or more of its registered capacity as primary frequency response which should be delivered linearly over a 5 second period from the inception of the generation loss or load change and an initial delay of no more than 1 second from the inception of the frequency change.

3.4.10 It is recognised that this specification may present a challenge to technology providers and manufacturers. However, it is believed that this specification is more achievable, at an earlier implementation date, than the df/dt triggered control option discussed above.

3.4.11 Simulations also showed a high degree of sensitivity to the ramp rate assumptions for Primary Response. It is recommended that these are specified explicitly within the Grid Code by setting out a maximum response delay of 1 second and specifying that response should be delivered linearly up to 10 seconds or 5 seconds as appropriate.

3.4.12 Whilst it is acknowledged that these proposals could resolve the issue for Plant in excess of 50MW, some consideration will still be required as to how this issue will be addressed in respect of Small Embedded Power Stations as this segment of the market is expected to grow in the future.

3.4.13 The studies have also demonstrated the effect on rate of change of system frequency against a credible set of future generating scenarios. As a conclusion it is seen that this will impact on Embedded Generation, in particular the effect on protection settings. It is therefore suggested that the Technical Subgroup Report is highlighted to the Distribution Code Review Panel for further consideration in respect of Embedded Generation.

3.4.14 A final point to note is the extent of reliance on wind generation to deliver frequency control in the analysis performed in the Technical Subgroup Report. Operators have little experience of this to date and it may be necessary to revisit the technical and commercial arrangements for the provisions of frequency response for asynchronous generators as more experience is gained.

3.4.15 Annex 7 contains text which sets out the very high level principles in addressing the need for a fast frequency response in order to address the issue of a diminishing contribution to system inertia from generating plants which are insensitive to changes in system frequency. The text has been drafted in the style of Grid Code change for illustrative purposes only.

3.5 Recommendations

Faster Frequency Response

3.5.1 Faster frequency response capability for asynchronous plant delivered within 5 seconds, for low and high frequencies, on users bound by the provisions of the Grid Code allows frequency response volumes to be reduced significantly in the situations analysed in the Frequency Response Technical Subgroup Report.

(a) The value of faster frequency response should be assessed by Frequency Response Workgroup, taking into consideration the costs of implementation and the benefits in reduced curtailment of generation from renewable sources and other balancing costs; and

(b) Subject to this assessment, proposals should be developed for the appropriate obligations and/or market arrangements to ensure sufficient frequency response capability is available to maintain system security for anticipated future generation and demand patterns.

Clearer Primary Response Requirements

3.5.2 The simulations conducted by the Frequency Response Technical Subgroup have demonstrated the sensitivity of frequency response requirements to the ramping capability of responsive generation. The Grid Code requirements for frequency response should be reviewed with the aim of clarifying the ramping capability required from responsive generation in terms of:

(a) adequacy of information provided on performance; and

(b) the need to stipulate minimum delay times and ramping capability for new providers.

Rate of Change of Frequency

3.5.3 The simulations performed by the Frequency Response Technical Subgroup give some indication to the potential change in the maximum Rate of Change of Frequency settings which needs to be considered in the context of the loss of mains protection deployed on embedded generation.

4 Frequency Response Workgroup Discussions

4.1 Current Frequency Response Services

4.1.1 The Workgroup began their examination of the frequency response commercial arrangements by considering the current obligations. These obligations can be found in:

- Statutory obligations[3];
- Security and Quality of Supply Standards (SQSS) obligations[4];
- Grid Code obligations[5]; and
- National Grid's Operational Standards.

4.1.2 System frequency is a continuously changing variable that is determined and controlled by the second-by-second (real time) balance between system demand and total generation. It is the role of National Grid as National Electricity Transmission System Operator to ensure that system frequency is maintained as close to 50Hz as possible whilst taking into account the operational and statutory limits. In exceptional circumstances the frequency may deviate outside of the statutory limits. Figure 4 below summarises the operational and statutory frequency limits.

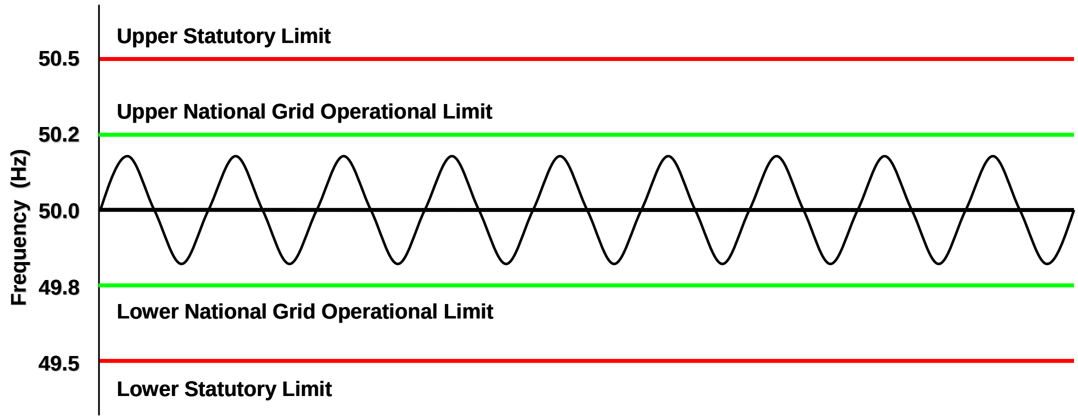


Figure 4 - Frequency Limits

4.1.3 As demand and generation fluctuate so to does the system frequency. If demand on the system is greater than generation, the system frequency falls while if generation is greater than demand the system frequency rises. In order to manage system frequency the System Operator primarily relies on frequency response.

4.1.4 There are two types of Frequency response; dynamic and non-dynamic:

- Dynamic frequency response is a continuously provided service used to manage the normal second by second changes on the system.
- Non-dynamic frequency response is usually a discrete service triggered at a defined frequency deviation.

[3] The Electricity Safety, Quality and Continuity Regulations 2002
http://www.legislation.gov.uk/uksi/2002/2665/contents/made

[4] NETS SQSS Issue 2.2 http://www.nationalgrid.com/NR/rdonlyres/5C1E8E34-B655-4D46-B9AF-EF6EE91B12B2/52026/NETSSQSSversion22FINALchangesremoved.pdf

[5] The Grid Code http://www.nationalgrid.com/uk/Electricity/Codes/gridcode/gridcodedocs/

4.1.5 Frequency response is procured by National Grid through one of three contract forms:

- Mandatory Frequency Response (MFR);
- Firm Frequency Response (FFR);
- Frequency Control by Demand Management (FCDM).

Mandatory Frequency Response (MFR)

4.1.6 MFR is an automatic change in active power output in dynamic response to a frequency change and it is an obligation for all generators that meet the requirements of the Grid Code (CC.6.3.7, CC Appendix 3) to have the capability to provide MFR. Having the ‘capability’ to provide frequency response refers to the ability to provide frequency response without the physical delivery of energy whereas ‘delivery’ is the physical delivery of energy on to the National Electricity Transmission System (NETS) used for frequency response.

4.1.7 The capability to provide MFR is a condition of connection for generators connecting to the NETS. MFR is not applicable for non-Balancing Mechanism Unit (BMU) or demand providers.

4.1.8 The current Grid Code obligation, illustrated below in figure 5 and 6, requires that a generation unit with a Completion Date after 1st January 2001 must provide:

- primary response (within 10 seconds, sustainable for 30 seconds);
- secondary response (within 30 seconds; sustainable for 30 minutes); and
- high frequency response (within 10 seconds, sustainable thereafter).

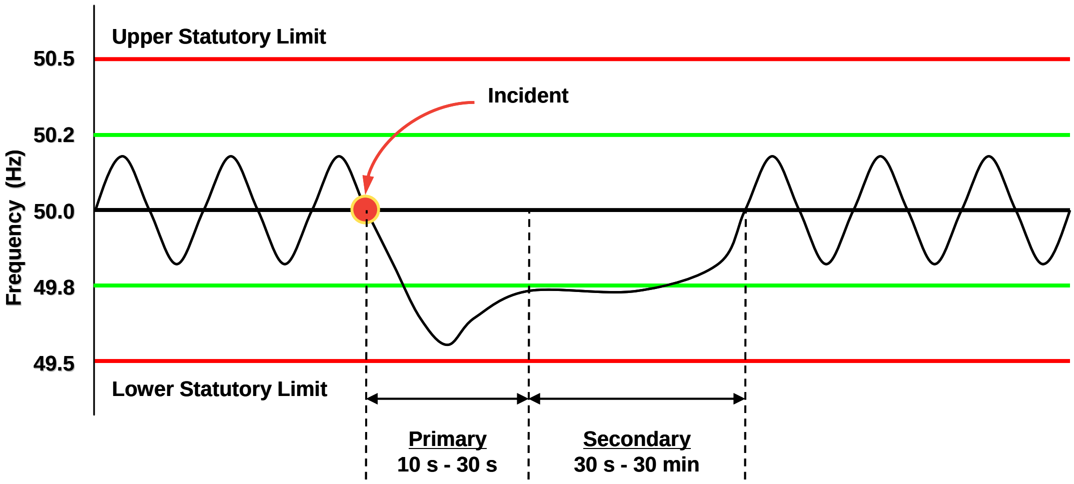


Figure 5 - Primary and Secondary Response

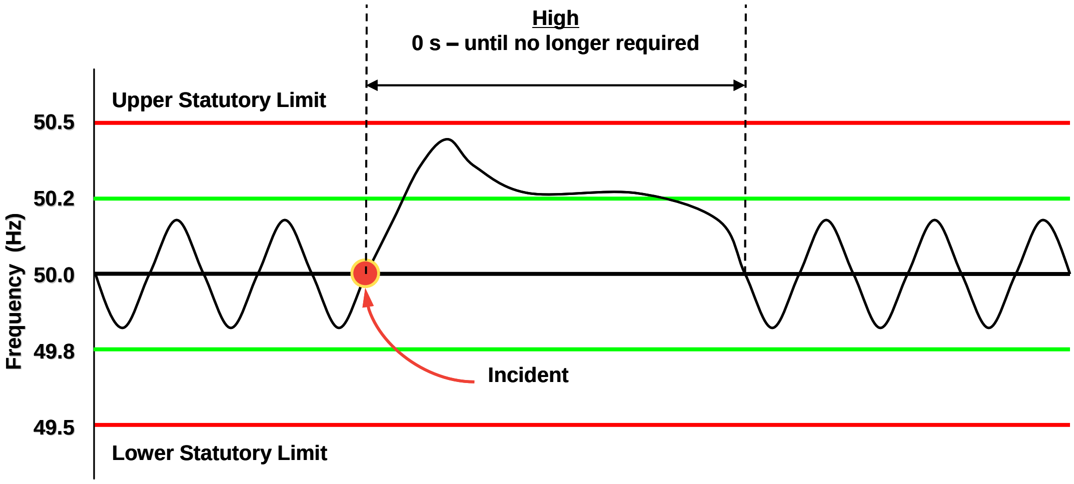


Figure 6 - High Response

4.1.9 The level of response for primary, secondary and high is 10% of a User's Registered Capacity (subject to operating level) and this can be found in figure CC.A.3.1 of the Grid Code.

4.1.10 MFR makes up the majority of the procured volumes and costs for frequency response. There are four main cost elements associated with procuring MFR:

- holding costs (based on capability prices submitted by the provider monthly for primary, secondary and high) which are payments made to the provider, by NGET as System Operator, to cover the costs when the provider is selected to provide response;
- energy costs which are payments made to the provider, by NGET as System Operator, to remunerate them the amount of energy delivered when providing frequency response;
- generator positioning costs, generally Bid-Offer Acceptance (BOA) costs, which are incurred in changing the generation output to enable response energy to be provided; and
- imbalance volumes which are caused by the delivery of response energy and offset by Applicable Balancing Services Volume Data (ABSVD)[6].

4.1.11 Once a new generating unit is built (or modified), National Grid must test its response capabilities to ensure the generating unit meets the minimum Grid Code requirements. Following successful assessment by National Grid, a Mandatory Service Agreement (MSA) as required under the CUSC is put in place (or amended), which allows National Grid to instruct the service when it is needed. Additionally, once an MSA is signed, National Grid adds the generator to the Frequency Response Price Submission (FRPS) system.

4.1.12 The FRPS system is a web based service that allows MFR providers to submit holding prices per MWh of primary, secondary and high response products on a monthly basis. After setup is complete, prices can be entered in to the system during the 5th and 15th Business day of each month applicable for the following month. Bid and Offer prices are entered into the Balancing Mechanism in line with the Grid Code requirements.

[6] ABSVD Methodology Statement http://www.nationalgrid.com/NR/rdonlyres/77770247-3E35-4842-B976-BEDEEAB67297/46017/ABSVDv3_April2011.pdf

Firm Frequency Response (FFR)

4.1.13 FFR is a form of commercial frequency response that is designed to compliment other sources of frequency response and delivers firm provision of Dynamic or Non-Dynamic Response to changes in Frequency.

4.1.14 National Grid procures FFR to manage the same incidents as MFR but unlike MFR, FFR is open to BMU and non-BMU providers, existing MFR providers and new providers alike.

4.1.15 The FFR service creates a route to market for providers whose services may otherwise be inaccessible whilst giving both National Grid and service providers a degree of stability against price uncertainty under the MSAs.

4.1.16 National Grid procures FFR through a monthly tender process. Once service providers successfully complete a pre-qualification assessment and sign onto a framework agreement, they can participate in the tender process. They can tender in for a single month or multi-months. Having considered the quality, quantity and the nature of the services, National Grid will accept the most economical tender. A successful tender then becomes contractually binding.

Frequency Control by Demand Management (FCDM)

4.1.17 FCDM provides non-dynamic frequency response through interruption of demand customers. The electricity demand is automatically interrupted when the system frequency transgresses the low frequency relay setting on site. The demand customers who provide the service are prepared for their demand to be interrupted for 30 minutes. Interruptions are likely to occur between approximately ten to thirty times per annum depending on the frequency set point.

4.1.18 FCDM is required to manage large deviations in frequency which can be caused by, for example, the loss of significantly large generation. The service is a route to market for demand-side providers, and compliments other non-dynamic service provisions.

4.1.19 Due to the bespoke nature of service provision, this service is provided through bilateral negotiations with providers. National Grid provides FCDM computer equipment, tests and commissions once the provider has installed the Tripping Relay Equipment and Communication Router. Once testing has been completed, a provider can join the scheme subject to signing the FCDM Ancillary Service Agreement.

4.1.20 Once a provider has agreed terms they are required to declare availability for each Settlement Period on a weekly basis. National Grid then will determine whether to accept this availability.

4.1.21 For each site where availability has been accepted by National Grid in a Settlement Period, an Availability Fee (£/MW/h) is paid against the Metered Demand in the Settlement Period of the site specified in the Agreement.

4.2 Workgroup Discussions

4.2.1 The Workgroup noted the work undertaken by the Frequency Response Technical Subgroup and their recommendations. It was agreed that appropriate commercial arrangements should be put in place to facilitate the provision of frequency response in the context of the technical conclusions.

4.2.2 The Frequency Response Workgroup concentrated discussion on the MFR provision and how this could be altered to facilitate improved frequency response in the future.

4.2.3 The Workgroup agreed that any arrangements would need to give suitable investment signals far enough in advance in order to be effective. It was also agreed that the obligations around frequency response, be they increased, maintained, reduced or removed, need to be clearly stated and defined within the Grid Code to give manufacturers clear requirements and Users confidence in the arrangements.

4.2.4 As the current MFR requirement is for Generators to have the capability, rather than the delivery, it is conceivable that a Generator will never be called upon for the physical delivery of energy if the System Operator can find the necessary response required at a more cost effective price.

4.2.5 Workgroup Members highlighted that the current MFR requirement for Generators may not be the most efficient method for ensuring the appropriate amount of frequency response is available to the System Operator and could lead to inefficient investment in capability.

4.2.6 Following the examination of existing frequency response obligations, the Workgroup discussed a number of high level options which have been summarised diagrammatically on the next page.

4.2.7 The Workgroup considered each option at a high level before determining if there was merit in giving it further consideration. Although not all of the options have progressed passed initial discussions, Sections 3 to 10 of this Workgroup Report describe each of the eight options and contain any additional analysis that the Workgroup undertook.

4.2.8 The Workgroup has not drawn out the status quo as an option above as these are presented as potential alternatives to the current arrangements. If an alternative is not developed the current arrangements will remain in place.

Frequency Response Services

- Mandatory Frequency Response (MFR)
  - Minimum capability obligation on Generators which is:
    - **Option A) Tradable with other providers -** A MFR obligation would be set for each generator but the capability and delivery could be traded with other providers to meet the obligation
    - **Option B) Shared onsite -** A MFR obligation would be set for each generator but the capability and delivery could be traded to other onsite providers
    - **Option C) Based on company portfolio -** A MFR obligation would be set based on a company portfolio and any mix of plant within the portfolio could be used to meet the obligation (i.e. more responsive units offsetting less responsive units)
    - **Option D) Based on generating technology -** A MFR obligation would be set based on the inherent technical ability of the generation technology to provide frequency response
    - **Option E) Supported with incentives -** A MFR obligation would be set and generators that do not meet the obligation would be penalised while generators which exceed the obligation would be rewarded
  - **Option F) System Operator provides response -** A MFR obligation would be removed from Generators and the System Operator would procure from providers or possibly develop and own frequency response equipment
  - **Option G) Day Ahead Auction -** Providers would submit frequency response prices from which the System Operator would procure the required level of frequency response for an operational day. This option could work with or without a MFR obligation
  - **Option H) Minimum obligation for Supplier -** A MFR obligation would be set for each supplier based on their demand requirements which could be met via procurement or provision of demand management.
- Firm Frequency Response (FFR)
- Frequency Control by Demand Management (FCDM)

4.3 Option A - Minimum capability obligation that is tradable with other providers

4.3.1 This option proposes to retain a minimum Grid Code obligation on a generator to provide frequency response capability but a generator would be able to trade away provision of that capability to other plant (which would still need to be capable of providing its own MFR requirement in addition). For example:

- Generator X, a new non-compliant generator, has a Registered Capacity of 100MW and can provide 6% of primary response in 10 seconds (current requirement is for 10% in 10 seconds)

- Generator Y, a fully complaint generator, also has a Registered Capacity of 100MW but can provide 14% of primary response in 10 seconds

- Under Option A, Generator X can contract with Generator Y for their additional 4% of primary response and both generators would be able to meet their primary response obligation.

4.3.2 This option would not preclude contracting with other providers of frequency response (e.g. demand providers) and would allow a generator to contract with other providers located across the National Electricity Transmission System (NETS) to provide additional response.

4.3.3 The Workgroup noted the following aspects that would need to be considered as part of Option A:

- all generators and their contracted providers would need to be tested;

- all generators and providers would need to have adequate metering installed to be able to monitor response energy delivery;

- all providers would need to be able to be selected to provide response at any time;

- arrangements would need to ensure that there was capability contract price discovery to enable efficient generator investment decisions to be made; and

- the point at which National Grid steps in to manage frequency response if a contracted provider does not deliver.

4.3.4 It was recognised that existing plant would have to meet the requirements of the Grid Code of their day and would not be required to meet requirements subsequently introduced into the Grid Code. The Workgroup also noted that under this option, generators that cannot meet their frequency response obligations could meet their obligation through contracting and should therefore not require a derogation.

4.3.5 The Workgroup agreed that Option A merited further discussion and consideration.

Impact on Operational Costs

4.3.6 The implementation of the arrangements as outlined above could have a number of impacts on operational costs. The outcome will depend on the contracting strategy of each generating unit, the generation technology that is providing the additional response and the operational period (i.e. level of demand).

4.3.7 There could be a situation in which less-responsive generation is running that cannot meet the overall response requirements. Therefore, a reduction in less-responsive generation (generation not compliant with the Grid Code) would be required to provide room for a corresponding increase in more-responsive generation and would lead to higher operational costs.

4.3.8 Alternatively, there could be a situation in which more-responsive generation is running that can meet more than the overall response requirements. Therefore, a reduction in less-responsive generation is not required to make room for more-responsive generation and would likely lead to lower operational costs.

4.3.9 Providers of additional response may have additional MW that they could provide to the energy market when the primary unit they have contracted with is not running. This could help providers to recover the cost of investment in a shorter period of time.

4.3.10 If each unit which does not or cannot meet the current mandatory requirement contracts with alternative technology, then it is likely that costs will be maintained or slightly increase. It is generally believed that the cost of new technology will be higher than the current costs of response. Therefore, if a generator is contracting with new technology, it is anticipated that this will be more expensive than the current cost levels. Although it is recognised that over time it may become cheaper to contract with alternative technology as it becomes more established.

4.3.11 It also needs to be noted that if the scenario materialises where the contracted unit fails to deliver the required response on behalf of the non-complaint generator it could lead to increased operational costs. The Workgroup assumes that the commercial ramifications that materialise from failure to deliver would be managed appropriately through the bilateral agreement between the generator and their provider of additional response.

Impact on Generation Investment Costs

4.3.12 It is anticipated with the ability to trade capability that generation investment costs could decrease as generators would not be required to invest in being able to provide frequency response capability themselves where it was less efficient to do so. Generators could contract with a provider who could provide the generators frequency response requirement more efficiently and at a lower cost.

4.3.13 These lower investment costs could be reflected in lower power prices although it should be noted that these requirements are forward looking and depending on the obligation, generation investment costs would vary.

Potential Cost Benefit

4.3.14 It would be anticipated that more efficient generation investment would lead to a decrease in the price of power. Quantifying this is difficult to do and relies on an understanding of how the market will operate with large amounts of variable generation, market behaviour and management of large portfolios.

4.3.15 Depending on the factors highlighted above, lower or higher operational costs could result in a corresponding change in Balancing Services Use of System (BSUoS) costs. Currently all BSUoS costs are socialised across all system users during each half hour. The Workgroup is aware of the recent approval of CMP202 which has removed BSUoS charges for lead parties of Interconnector BM Units[7] and the ongoing CMP201 which seeks to remove BSUoS charges from Generation[8].

4.3.16 If BSUoS costs increased it is difficult to know if they would be offset by lower power prices through efficient generation investment. Although, increases in BSUoS costs would provide some incentive on system users to provide response during periods of high costs (high costs caused by response provision).

4.3.17 Alternatively, if BSUoS costs decreased and lower power prices were seen through efficient generation investment an overall cost reduction could be seen which could translate into lower prices for consumers.

4.3.18 It also needs to be noted that if the scenario materialises where the contracted unit fails to deliver the required response it could lead to increased operational and BSUoS costs.

Benefits of Option A

4.3.19 There are a number of benefits that can be identified:

- promotes development of and facilitates access for alternative generation technologies that may not be able to meet current Grid Code requirements;
- maintains system security risk to current levels;
- provides flexibility in the provision of response volumes for mandatory providers;
- potential for lower power prices, and lower operational and BSUoS costs;
- additional frequency response and MW available when alternative response provider is running and main plant is not; and
- if the market size increases, existing sites may add on-site technology to increase their frequency response ability to contract out.

Disadvantages of Option A

4.3.20 There are a number of disadvantages that can be identified:

- any outage on the additional response provider technology would mean primary generator could not meets its obligation;
- operating and BSUoS costs could increase;
- additional testing and approving of alternative technologies would be required;
- need to improve metering of response volumes provided;
- increased optimisation complexity;

[7] CMP202 Decision Letter - http://www.nationalgrid.com/NR/rdonlyres/6030B915-F3E0-4418-BF08-CA6B1CC5C4BD/55635/CMP202D.pdf

[8] CMP201 Code Administrator Consultation - http://www.nationalgrid.com/NR/rdonlyres/DDF09C57-F559-4F3D-91D6-11070D3DDF93/55346/CMP201CodeAdministratorConsultation.pdf

- increased interaction with the energy market;

- increased monitoring of contracts and publication of contract information; and

- depending on the plant providing the additional response, investment savings could translate into operational costs.

4.4 Option B - Grid Code Obligation with the Ability to Share Obligation On-site

4.4.1 This option proposes to retain a minimum Grid Code obligation on a generator to provide frequency response capability but they would be able meet any shortfall in response capability through the use of on-site alternative technologies such as batteries or flywheels. For example:

- Generator X, a new non-compliant generator, has a Registered Capacity of 100MW and can provide 6% of primary response in 10 seconds (current requirement is for 10% in 10 seconds)

- To address the 4% primary response deficit, Generator X develops additional on-site technology that can produce at least 4% primary frequency response.

4.4.2 The Workgroup did not believe that having the alterative technology based on-site would preclude another party from owning and operating it.

4.4.3 The Workgroup agreed that Option B merited further discussion and consideration.

Impact on Operational Costs

4.4.4 As all generators will be compliant with the Grid Code (via self provision or alternative on-site response technology), costs should be similar to current levels (dependent on the cost of new technologies in providing the additional response volumes).

4.4.5 As the additional on-site technologies may also be available to provide response when the corresponding generation is not available, costs could decrease as there could be more response volume available to the System Operator.

4.4.6 A scenario could occur in which the primary plant is not running but enough additional on-site response is available that it would prevent the need to deload less-responsive generators elsewhere on the system.

4.4.7 Another scenario could materialise where the contracted alternative on-site response unit fails to deliver the required response on behalf of the non-compliant generator which could lead to increased operational costs.

Impact on Generation Investment Costs

4.4.8 Option B allows a generator to determine the most cost effective manner in determining how they meet their Grid Code frequency response obligations i.e. rather than invest in generation, the investment may be more efficiently provided via alternative technology.

4.4.9 However, there could be increased investment required from a generator to install alternative technologies in addition to their primary unit. There could also be costs associated with gaining the necessary experience depending on the technology employed.

4.4.10 These costs may be offset by the savings in not having to ensure their primary unit is able to provide their entire obligation.

4.4.11 Alternative on-site technology could increase the entry capacity required for the site and the additional on-site unit could provide MW to the energy market rather than solely provide frequency response. Whilst a higher entry capacity might result in different Grid Code obligations that need to be met, additional MW available for the energy market may hasten the return on investment. The generator would have to determine the best deployment of MW which is the same as the current arrangements when operating at peak load.

4.4.12 There is the potential that it is more expensive to provide the additional response technology on-site rather than at other sites.

Potential Cost Benefit

4.4.13 Initial discussions indicate that there could be lower operational and generation costs which could translate into lower costs passed on to the consumer.

4.4.14 Arguably a generator will determine the most cost effective way to meet their Grid Code response obligations which could result in lower operational costs compared to the current arrangements. Additional on-site capacity could also result in more MW available in the energy market leading to lower power prices.

4.4.15 The Workgroup also recognised that if the additional on-site response was a storage based technology it could be used to smooth out intermittent generation which could reduce BSUoS costs.

Benefits of Option B

4.4.16 There are a number of benefits that can be identified:

- promotes development of and facilitates access for alternative generation technologies that may not be able to meet current Grid Code requirements;
- maintains system security risk to current levels;
- provides flexibility in the provision of response volumes for mandatory providers;
- potential for lower power prices, and lower operational and BSUoS costs;
- unlike Option A there is no requirement to provide additional metering as the provision of response is provided at the generation site;
- unlike Option A there would not need to be additional monitoring of response volumes;
- optimisation would be of a similar complexity to current arrangements;
- unlike Option A there would likely be lower interaction with the energy markets and no need to monitor and publish response contracts; and
- additional frequency response and MW available when additional response unit is running and main plant is not,

Disadvantages of Option B

4.4.17 There are a number of disadvantages that can be identified:

- any outage on the alternative technology would mean generator could not meets its obligation;
- increased generation investment costs;
- reliability risks associated with new technology;
- limits the technologies that would be available to provide response (i.e. demand side providers would not be able to provide on-site response);
- saturation of the market by having sites meeting the frequency response requirements;
- likely to be most effective capital solution but not necessarily most overall effective solution; and
- it could be more expensive to provide the technology on-site rather than at other sites.

4.5 Option C - Minimum capability obligation based on company portfolio

4.5.1 This option proposes to retain a minimum Grid Code obligation on a generator to provide frequency response capability but the requirement would be set based on the company portfolio. The generator would then choose how to meet their obligation with units from the portfolio. For example:

- A generator has two power stations within their portfolio, Station X and Station Y. Using the current primary response obligations, the portfolio has to be able to deliver 10% of Registered Capacity in 10 seconds.
- Station X, a new non-compliant station, has a Registered Capacity of 100MW and can provide 6% of primary response in 10 seconds
- Station Y, a fully complaint generator, also has a Registered Capacity of 100MW but can provide 14% of primary response in 10 seconds
- Under Option C, the generator can use the additional 4% of primary response from Station Y to offset Station X which would meet the primary response obligations placed on the portfolio.

4.5.2 As the obligation would be set on the company portfolio it would allow a generator to determine the most efficient way to meet their obligations using the plant within their portfolio. This flexibility would allow a generator to have more responsive plant offset less responsive plant rather than having each generator meet a minimum requirement. It was thought that by allowing the obligation to be met across a portfolio it would save on capital costs for future projects.

4.5.3 The Workgroup agreed that a portfolio could contain one unit or a number of units but noted that when a company acquires new units their frequency response requirements would alter. A frequency response obligation that fluctuates based on a company portfolio would likely be difficult and costly to monitor whilst causing operational uncertainty for the System Operator.

4.5.4 It was also recognised that while Option C might afford more flexibility to those generators with large portfolios, it would not permit any additional flexibility for generators with a single station that are required to provide frequency response. The Workgroup agreed that any option would need to give equal flexibility to all generators and not just those with large portfolios.

4.5.5 The Workgroup recognised the parallels that Option C had with other options, namely A and B, and agreed that there was no discernable benefit to Option C over other options. The Workgroup therefore determined that Option C should not be progressed any further.

4.6 Option D - Minimum capability obligation based on generating technology

4.6.1 This option proposes to retain a minimum Grid Code obligation on a generator to provide frequency response capability but the requirement would be set based on the technology utilised. For example:

- Generator X, a Combined Cycle Gas Turbine (CCGT), has a Registered Capacity of 100MW and, based on the inherent technical ability of the this generating technology, can provide 6% of primary response in 10 seconds (current requirement is for 10% in 10 seconds)

- Generator Y, a Pumped Storage Hydro facility, also has a Registered Capacity of 100MW and, based on the inherent technical ability of the this generating technology, can provide 14% of primary response in 10 seconds

- Under Option D, the combination of Generator X and Generator Y results in the System Operator having the required amount of primary frequency response (based on the existing requirement)

4.6.2 It was recognised that allowing each technology to provide a level of frequency response best suited to it might be the most cost effective option as it would not put expensive and uneconomical requirements on generators. This could result in significant capital cost savings for generators which could lead to lower power prices.

4.6.3 It was also understood that whilst Option D could lead to lower capital costs there could be an increase in BSUoS costs. If the mix of generation on the system put the System Operator short of the required level of frequency response for the operational day, it could mean that less economic actions need to be taken to account for the shortfall in available frequency response.

4.6.4 It was also questioned how each generating technology would be assessed to determine a minimum level of response. The Workgroup believed that this would come from manufacturers or testing as part of the compliance process.

4.6.5 The Workgroup agreed that whilst Option D could be the most cost effective option in terms of the provision of frequency response by generators, there are a number of concerns regarding system security and whether the future mix of generation would be appropriate to meet system requirements.

4.6.6 The Workgroup determined that Option D should not be progressed any further.

4.7 Option E - Minimum capability obligation supported with incentives

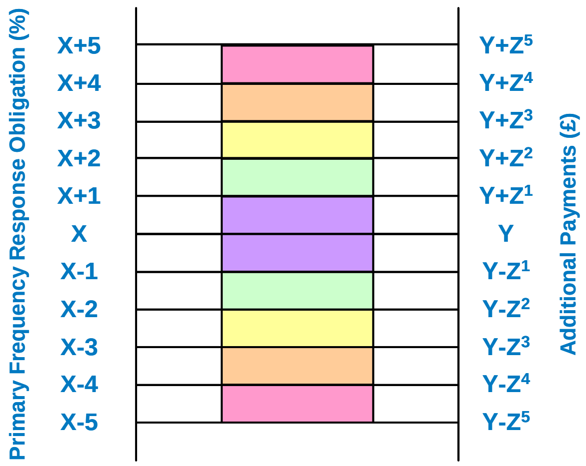
4.7.1 This option proposes to retain a minimum Grid Code obligation on a generator to provide frequency response capability but rewards or penalises based on installed capacity. For example:

- Generator X, a new non-compliant generator, has a Registered Capacity of 100MW and can provide 6% of primary response in 10 seconds (current requirement is for 10% in 10 seconds)

- Generator Y, a fully complaint generator, also has a Registered Capacity of 100MW but can provide 14% of primary response in 10 seconds

- Under Option E, Generator Y would receive additional income from providing primary frequency response above the minimum requirement whilst Generator X would be exposed to additional cost for not being able to meet the minimum requirement.

4.7.2 This income would be in addition to the income that generators already receive for providing frequency response (i.e. holding and energy payments). It is envisaged that generators who cannot meet the minimum obligation would pay a fee for each percent that they are short of the required minimum. Those generators that are able to provide frequency response above the minimum obligation would receive a payment for each percent above. Figure 7 below summarises the proposed incentives.



Where:
X = Minimum Obligation
Y = Existing Frequency Response Payment
Z = New Frequency Response Incentive

Figure 7 - Incentive structure

4.7.3 The Workgroup noted that this would penalise generation technology that finds it inherently difficult to provide frequency response for technical reasons but agreed that it is not expected that the costs for under provision would dissuade a generator from a particular choice of generation technology.

4.7.4 The Workgroup also believed that it could prove more economical for some generators to pay an additional cost for not being able to meet the minimum requirements rather than incurring the capital cost that would be required to allow the minimum obligations to be met.

4.7.5 The Workgroup have not developed this option any further than initial discussions but note that this option may have some merit worth investigating further.

4.8 Option F - System Operator provides response

4.8.1 This option proposes to reduce or remove the minimum Grid Code obligation on a generator to provide frequency response capability and instead have the System Operator procure the necessary frequency response volumes on a bilateral basis. For example:

- Generator X, a new generator, has a Registered Capacity of 100MW and can provide 6% of primary response in 10 seconds (frequency response requirement removed)

- Generator Y, a new generator, has a Registered Capacity of 100MW and can provide 14% of primary response in 10 seconds

- Under Option F, National Grid would approach Generator X and Generator Y to discuss procurement of frequency response and agree terms on a bilateral basis. The amount of frequency response procured by National Grid would be based on plant outage, unavailability and system security. Both generators are compliant in this example as the obligation has been removed.

4.8.2 Payments would be generator specific and could be based on existing holding and response energy payment mechanisms. Alternatively, for new or life-extension generation, the payment could reflect an agreed amount of capital contribution to deliver the capability or a combination of the two. Payments for long term contracts could be index linked. Enhanced capability, either quantity or speed of response, would attract higher payment.

4.8.3 Contracts would be required for the service provision once a provider was appointed to ensure appropriate terms and conditions and to cover items such as term, payment and non-delivery. Plant would have to be tested to demonstrate it can achieve its capability profile. Compliance process would apply and National Grid could have option to re-negotiate price if capability no longer meets contracted position.

4.8.4 The Workgroup also discussed a scenario in which National Grid developed and owned frequency response equipment to meet system requirements. Whilst initially discussed it was considered unlikely to be an option going forward due to licensing restrictions and regulatory issues.

Impact on Operational Costs

4.8.5 Increased System Operator costs in terms of resourcing and running the procurement exercise.

4.8.6 The onus for the provision of frequency response would move from the generators to the System Operator and the Workgroup questioned if the System Operator is best placed to get the best provision. Arguably operational costs would increase if the System Operator is not best placed to get the best provision.

4.8.7 The System Operator would be exposed to fuel price risk if the capability procured through the tender process meant that the majority of frequency response came from units utilising a particular fuel source.

Impact on Generation Investment Costs

4.8.8 Lower investment costs could be seen for generators as not all generators would have to provide frequency response capability.

4.8.9 If providers were identified through a tender, this could show longer investment signals which could lead to more efficient and certain investment.

4.8.10 Price risk moved to System Operator with long term contracts which could be indexed linked by fuel but it would provide an incentive on generators to reduce operational costs to maximise margin.

Potential Cost Benefit

4.8.11 It is unclear if the increased System Operator costs to run a procurement process and any loss in efficiency with the System Operator not obtaining the best provision would be offset by potentially lower generator investment costs which could materialise in lower power prices.

4.8.12 Arguably the System Operator is not best placed to be making decisions that could expose them to fuel price risk and it adds additional complexity to the System Operator role which would likely materialise as increased operating costs.

Benefits of Option F

4.8.13 There are a number of benefits that can be identified:

- more options for providers to determine how and if they wish to provide frequency response;
- more options for National Grid to pick more economic and efficient frequency response solution;
- prevents consumer being exposed to cost of capability provided but unutilised frequency response cost;
- lower investment costs for generators;
- flexibility around contract duration and pricing structure; and
- actually procure based on the frequency response requirements.

Disadvantages of Option F

4.8.14 There are a number of disadvantages that can be identified:

- cost for development and implementation of appropriate IS systems;
- system security risk may not be maintained to current levels;
- increased complexity and additional process;
- increased System Operator costs;
- over procurement would be necessary to ensure enough frequency response available on the day;

- having one central buyer is arguably not the most efficient way to address the issue;

- not a very competitive solution or responsive to market signals; and

- long term contracts do not promote innovation and blocks new entrants.

4.8.15 The Workgroup agreed that whilst Option F had some benefits it did not seem that having a single procurer would encourage the most efficient solution. There was also concern that this option would not facilitate future innovation and could block new entrants from participating if long term contracts are agreed.

4.8.16 The Workgroup determined that Option F should not be progressed any further.

4.9 Option G - Day Ahead Auction

4.9.1 This option proposes to reduce or remove a minimum Grid Code obligation on a generator to provide frequency response capability and replace it with a day ahead auction.

4.9.2 To ensure that a mix of plant capable of securing the system is generating on any particular day, it is envisaged that at the day-ahead stage, the auction process would be initiated. The concept is similar to that of the Firm Frequency Response (FFR) tender but carried out on a daily basis rather than monthly. The Workgroup also recognised that a week ahead auction could be an alternative option if the timescales for a day-ahead auction proved too challenging or as an interim step between current arrangements and progressing to a day-ahead model.

4.9.3 To participate in the auction, which would be open to generation or demand-side providers, it would be necessary to be confident in the bidders' ability to deliver the agreed levels of response. Thus there may be a requirement for some pre-qualification process. It is likely the requirements for the Day Ahead Auction participants would be similar to that of FFR participants which are:

- have suitable operational metering;

- pass the FFR Pre-Qualification Assessment;

- deliver a minimum 10MW Response Energy;

- operate at their tendered level of demand/generation when instructed (in order to achieve the tendered frequency response capability);

- have the capability to operate (when instructed) in a Frequency Sensitive Mode for dynamic response or change their MW level via automatic relay for non-dynamic response;

- communicate via an Automatic Logging Device; and

- be able to instruct and receive via a single point of contact and control where a single FFR unit comprises of two or more sites located at the same premises.

4.9.4 For simplicity, it is expected at this time that the existing services of Primary, Secondary and High would remain although it is feasible that other products could be defined in the future. It is also assumed that the auction would be Balancing Mechanism Unit (BMU) specific, but a generic product could be developed.

4.9.5 Assuming that the frequency response auctions were to take place after submission of indicative Physical Notifications (PNs), a number of parameters would need to be submitted for assessment as part of the auction. The list below may not be exhaustive, but is a likely minimum requirement.

- MW of response offered - Primary, Secondary and High;

- required MW loading or de-loading to achieve the response offered;

4.9.6 It is possible that this volume could be treated as equivalent to a bid or offer such that further energy trading would not be required, thus removing the price risk of not being able to cover a resulting physical position at the expected price.

- the positional price (£/h) for delivering the capability to the system;

4.9.7 This would cover the cost of de-loading or loading to the appropriate level.

- an energy price for delivered energy resulting from frequency changes; and

- an initiation price.

4.9.8 This would be particularly relevant for plant not expected to be running to cover start-up costs and would allow submission of bids for all periods during the day giving assurance that contiguous periods would be bought.

4.9.9 With the indicative PNs and submissions from potential response providers, whether expected to be running or not, the System Operator would assess the bids in order to determine the most efficient way of meeting the frequency response requirements for the following day.

4.9.10 Accepted bids would be expected to deliver as bid and non-delivery would need to be priced appropriately. It is likely that an appropriate monitoring process for delivery would be developed in parallel.

4.9.11 It is envisaged that within-day changes to the despatch decisions should be possible, and the BM would remain a mechanism to make such changes.

4.9.12 The Workgroup noted that Option G would not have to be based on the FFR framework but this was used as a starting point for discussion. Options could include:

- an FFR based mechanism with a mandatory obligation;

- an FFR based mechanism with a reduced obligation;

- an FFR based mechanism with no obligation;

- an alternative mechanism with a mandatory obligation;

- an alternative mechanism with a reduced obligation;

- an alternative mechanism with no obligation;

4.9.13 The Workgroup agreed that Option G merited further discussion and consideration.

Impact on Operational Costs

4.9.14 The Workgroup noted that with this option there would a potential systems impact to provide a day-ahead auction platform. It was recognised that the closer a process gets to real time the level of automation required increases and a day-ahead auction platform would require a large amount of automation which would likely have a large cost associated with it.

4.9.15 Along with the development of an appropriate platform there is the ongoing maintenance and resource cost that would be required. It was highlighted that this could have an impact on Electricity National Control Centre resources.

4.9.16 It was also noted that there would likely be interaction with other ancillary services and that operational systems would need to optimise the frequency response service with these other services.

4.9.17 If the system supported a single cost of response that could be submitted and if it takes away bid/offer analysis that is currently undertaken, it will provide better optimisation.

4.9.18 Prices could be more volatile at the day-ahead stage and could be higher compared to the week/month ahead.

4.9.19 It was highlighted that for demand side providers the certainty of their response capability increases closer to real time as demand becomes more certain.

Impact on Generation Investment Costs

4.9.20 The Workgroup suggested that the only reduction in generation investment costs would likely correspond with a reduction in obligation over time.

Potential Cost Benefit

4.9.21 A large capital expenditure would likely be required to establish a day-ahead auction platform and ongoing operational expenditure would be required to maintain and operate the system.

4.9.22 There are potential efficiencies in providing a day-ahead auction solution as it facilitates wider participation and enables all providers to be more certain of aspects such as fuel prices and system demand which could translate into lower operational costs for them. Providers would optimise their plant and provide response in the most efficient means possible.

4.9.23 There was concern expressed that if there is no obligation to provide response capability it could lead to higher BSUoS costs and put the system at greater risk.

Benefits of Option G

4.9.24 There are a number of benefits that can be identified:

- an auction for frequency response should ensure that the System Operator is able to procure a suitable mix of plant at the day-ahead stage such that sufficient frequency response is available for the anticipated requirement;
- all available plant should be able to participate as it would not be constrained by long NDZs etc which should result in greater price competition than within-day actions;

- plant scheduled to run would be able to provide best prices and therefore an efficient outcome should result giving the optimal mix of plant on the day;

- efficiency is gained by optimising both the energy and response decisions at the same time;

- encouraging other technologies and providing a platform for participation;

- could be a more gradual implementation compared to other commercial arrangements as it is similar to existing mechanisms;

- obligations could remain the same and if successful could be reduced over time;

- if the market size increases, existing sites may add on-site technology to increase their frequency response ability to participate;

- unlike the month ahead FFR market, the risk to providers with exposure to fuel / power price diminishes closer to real time.

Disadvantages of Option G

4.9.25 There are a number of disadvantages that can be identified:

- a day-ahead frequency response market would add a level of complexity and additional process;

- within day changes would still need to be managed by National Grid and plant failures would need to be managed through appropriate non-delivery charges and within-day despatch;

- likely to be expensive to develop and ongoing operational costs would depend on the type of system developed;

- providers may opt to participate in the energy market rather than the frequency response auctions which could put the system at unacceptable risk.

4.10 Option H - Minimum obligation for Supplier

4.10.1 This option proposes to introduce a minimum Grid Code obligation on a supplier to procure or provide frequency response capability based on the level of demand they are forecasting for a particular day. For example:

- Supplier A, has forecasted demand of 200MW for a particular day

- Generator X, has a Registered Capacity of 150MW and can provide 10% of primary response in 10 seconds (current requirement is for 10% in 10 seconds)

- Generator Y, has a Registered Capacity of 150MW and can provide 10% of primary response in 10 seconds

- Under Option H, the supplier would contract with Generator X and Generator Y to provide the necessary frequency response based on their forecasted demand

4.10.2 The Workgroup identified that there seemed to be some benefit in placing the obligation on Suppliers to procure frequency response in proportion to the amount of generation they needed to meet their expected demand.

This would allow the correct amount of frequency response to be available for any given level of demand, as well as helping Suppliers to understand the benefits associated with services such as frequency response.

4.10.3 The Workgroup also commented that demand is a useful and flexible way to respond to a frequency situation but in the past Suppliers have not been able to actively participate to frequency response due to technological limitations.

4.10.4 The Workgroup agreed that whilst there could be some benefits associated with this option it would be a complex solution that would require significant changes in requirements and utilisation of technology such as smart meters.

4.10.5 It was also recognised that if the supplier was expected to provide frequency response rather than procure it from other sources, it could be challenging to provide adequate frequency response in times of low demand.

4.10.6 Overall, the Workgroup did not view this as a viable option due the infrastructure (ie smart meters) required which is not available at this time but noted that, once the infrastructure is in place, it could be an option in the future.

4.11 European Network Codes

4.11.1 The Workgroup recognise the work that is ongoing on the European Network Codes (ENCs), specifically within the Network Code for Requirements for Grid Connection applicable to all Generators (RfG).

4.11.2 The development of the Network Code for Requirements for Grid Connection applicable to all Generators entered its formal phase after ENTSO-E received an invitation from the European Commission on 29 July 2011. The Commission officially requested ENTSO-E to draft this network code in line with Regulation (EC) 714/2009 and based on the Framework Guidelines on Electricity Grid Connection, published by ACER on 20 July 2011.

4.11.3 ENTSO-E launched a public consultation on the Network Code for Requirements for Grid Connection applicable to all Generators on 24 January 2012, which closed on 20 March 2012 ENTSO-E received over 6000 comments on the draft Network Code RfG.

4.11.4 On 13 July 2012, ENTSO submitted the Network Code on Requirements for Grid Connection Applicable to all Generators (RfG) to the Agency for the Cooperation of Energy Regulators (ACER).

4.11.5 At the time of writing, the final Network Code RfG, as well as its supporting documentation, is now subject to a three month evaluation period by ACER as prescribed in Regulation (EC) 714/2009.

4.11.6 Within GB, the current generator requirements are based on the following categories:

- Small (NGET <50MW, SPT <30MW, SHETL <10MW);
- Medium (NGET 50MW - 100MW, SPT N/A, SHETL N/A); and
- Large (NGET >100MW, SPT >30MW, SHETL >10MW).

4.11.7 Under the ENCs generator requirements are based on the following categories:

- A (800W - 1MW connected below 110kV);
- B (1MW - 10MW connected below 110kV);
- C (10MW - 30MW connected below 110kV); and
- D (>30MW or connected at 110kV or above).

4.11.8 Under the RfG, parameters for frequency response performance are specified by the Transmission System Operator (TSO) in accordance with Article 10 (2) (c) but in general these are similar to that required by the GB Grid Code. The TSO must define the parameters for minimum frequency response capability as a percentage of Registered Capacity (Pmax) which is between 1.5 – 10%, the Initial delay time shall be less than 2 seconds (which is not covered in the Grid Code) and full delivery of Active Power shall be achieved as specified by the TSO but shall be less than 30 seconds. Generating Units are to be capable of providing full Active Power frequency response (to be specified) for a period of between 15 minutes and 30 minutes and Generators must operate between their maximum and minimum headroom[9].

4.11.9 The above requirements only apply to categories C and D under RfG. The Workgroup were not aware of any elements of the ENCs that would prohibit the implementation of the any of the commercial arrangements discussed.

[9] See Article 10 (2) (c) - https://www.entsoe.eu/fileadmin/user_upload/_library/consultations/Network_Code_RfG/120626_final_Network_Code_on_Requirements_for_Grid_Connection_applicable_to_all_Generators.pdf

5 Workgroup Consultation

5.1 Summary

5.1.1 The Workgroup has consulted with Authorised Electricity Operators (AEOs) on the proposals identified in this Workgroup Report. The consultation period opened on 18 September 2012 and closed on 30 October 2012. There were 9 responses received during the consultation period. A copy of the Workgroup Consultation is available on the National Grid website at:

http://www.nationalgrid.com/uk/Electricity/Codes/gridcode/consultationpapers/current/Frequency_Response/

5.1.2 The below table provides an overview of the support received for each of the commercial and technical options developed by the Workgroup and the Workgroup conclusions based on the received responses. A more detailed summary of each respondents support and full copies of the responses are included in Annex 3.

Commercial Options	Consultation Respondents Support	Workgroup Conclusion	Recommend Further Development
Option A - Minimum capability obligation which is tradable with other providers	Merits further investigation x 5 Unsupportive x 3 No comment x 1	A complex option that does not appear to be compatible with European Network Codes as units will have a European requirement to have capability which is unlikely to be tradable.	✘
Option B - Minimum capability obligation which is shared on-site	Merits further investigation x 3 Unsupportive x 5 No comment x 1	Whilst possibly less complex than Option A, it does not appear feasible with the current technology available. The Workgroup agreed that this should not be precluded from being developed in the future if new technology is developed.	✘
Option C - Minimum capability obligation which is based on company portfolio	Merits further investigation x1 Unsupportive x 7 No comment x 1	An obligation that fluctuates based on a company portfolio would likely be difficult and costly to monitor whilst causing operational uncertainty for the System Operator. It was also agreed that this option would favour larger portfolio players with no discernable benefit to the wider market.	✘

Commercial Options	Consultation Respondents Support	Workgroup Conclusion	Recommend Further Development
Option D - Minimum capability obligation which is based on generating technology	Merits further investigation x 3 Unsupportive x 5 No comment x 1	Whilst possibly a cost effective option it may not deliver the appropriate mix of generation to meet system requirements. It would also require significant testing in order to determine the inherent frequency response capability of each unit and therefore does not seem to be a sensible solution.	✘
Option E - Minimum capability obligation which is supported with incentives	Merits further investigation x 5 Unsupportive x 3 No comment x 1	This could be the wrong way to incentive the right behaviour and achieve the desired outcome of frequency response from a wider range of sources. The numbers involved have to be significant to cause any change in behaviour or services available. The effectiveness of the solution may also be limited by the European Network Codes.	✘
Option F - System Operator provides response	Merits further investigation x 5 Unsupportive x 3 No comment x 1	Removing a capability requirement and having a single procurer would not encourage the most efficient solution. There was also concern that this option would not facilitate future innovation and could block new entrants from participating if long term contracts are agreed. It could also lead to difficulties in managing the system.	✘
Option G - Day Ahead Auction	Merits further investigation x 6 Unsupportive x 2 No comment x 1	Implementing a Day Ahead Auction was agreed to not be feasible at this point but the Workgroup did conclude that the existing commercial arrangements should be developed further to make frequency response tenders closer to real time and accommodate the Frequency Response technical recommendation. This would help to achieve the maximum benefit from existing products without introducing significant market changes.	✓

Commercial Options	Consultation Respondents Support	Workgroup Conclusion	Recommend Further Development
Option H - Minimum obligation for Supplier	Merits further investigation x 1 Unsupportive x 6 No comment x 2	The level of infrastructure required to implement this option is not currently in place and it is unlikely to result in efficient procurement as the system is dynamic and based on a number of criteria that the System Operator is best placed to assess.	✘

Technical Options	Consultation Respondents Support	Workgroup Conclusion	Recommended for Implementation
Requirement for 5 second Frequency Response on asynchronous plant	Supportive x 4 Unsupportive x 4 No comment x 1	There is a growing amount of asynchronous generation on the National Electricity Transmission System (NETS). To achieve the necessary frequency response provision in times of low demand and high wind asynchronous generation needs to have a requirement to provide frequency response in a shorter timescale to offset its lack of contribution to system inertia.	✓
Clearer Primary Response Requirements for synchronous plant	Supportive x 5 Unsupportive x 3 No comment x 1	The Grid Code requirements should be reviewed and clarified.	✓

6 Impact & Assessment

6.1 Background

6.1.1 This assessment is only for the technical options (rapid frequency response for asynchronous plant, and improved clarity around frequency response commencement and delivery profile for synchronous plant) that the Workgroup recommends are progressed under the Grid Code.

6.1.2 It does not include the commercial options that are recommended to be examined by the Balancing Services Standing Group (BSSG) and Commercial Balancing Services Group (CBSG).

6.1.3 A summary of the Workgroup recommendations is available in Section 7.

6.2 Impact on the Grid Code

6.2.1 The following sections are areas of the Grid Code that may require amendment to implement the Workgroup recommendations:

- Glossary & Definitions (GD)
- Planning Code (PC)
- Connection Conditions (CC)
- Operating Code No. 2 (OC2)
- Operating Code No. 5 (OC5)
- Balancing Code No. 2 (BC2)
- Balancing Code No. 3 (BC3)
- Data Registration Code (DRC)

6.2.2 The Workgroup did not develop text to give effect to the recommendations but illustrative legal text can be found in Annex 7. This illustrative legal text concentrates on the Connection Conditions but the sections identified above will require review to ensure no changes are required. It is proposed that text is developed and brought to the March 2013 Grid Code Review Panel prior to Industry Consultation.

6.3 Impact on National Electricity Transmission System (NETS)

6.3.1 The proposed changes will not have any adverse impact on the NETS. The new requirement will improve the ability of the System Operator to manage large frequency deviations in circumstances where there is a lack of 'natural' inertia (i.e. when a high proportion of generation is from asynchronous plant).

6.4 Impact on Grid Code Users

6.4.1 The proposed changes to the Grid Code will create a new requirement for asynchronous generation to be able to provide frequency response within 5 seconds. A ‘go-live’ date for this requirement will be identified and all new asynchronous generation with a completion date post the 'go-live' date will need to be compliant with the new requirement.

6.5 Impact on Greenhouse Gas emissions

6.5.1 The proposed changes will not have a material impact on Greenhouse Gas emissions.

6.6 Assessment against Grid Code Objectives

6.6.1 National Grid considers that the proposed changes would better facilitate the Grid Code objective:

(i) to permit the development, maintenance and operation of an efficient, coordinated and economical system for the transmission of electricity;

The Workgroup recommendation will permit a more efficient and economic transmission system by improving the ability of the System Operator to manage system frequency in circumstances where a large proportion of generation is being produced by asynchronous plant.

(ii) to facilitate competition in the generation and supply of electricity (and without limiting the foregoing, to facilitate the national electricity transmission system being made available to persons authorised to supply or generate electricity on terms which neither prevent nor restrict competition in the supply or generation of electricity);

The proposal has a neutral impact on this objective

(iii) subject to sub-paragraphs (i) and (ii), to promote the security and efficiency of the electricity generation, transmission and distribution systems in the national electricity transmission system operator area taken as a whole; and

The Workgroup recommendation will promote system security by improving the ability of the System Operator to manage system frequency in circumstances where a large proportion of generation is being produced by asynchronous plant.

(iv) to efficiently discharge the obligations imposed upon the licensee by this license and to comply with the Electricity Regulation and any relevant legally binding decisions of the European Commission and/or the Agency.

The proposal has a neutral impact on this objective

6.7 Impact on core industry documents

6.7.1 The proposed modification may require changes to be made to the System Operator Transmission Owner Code (STC) and this will have to be assessed as part of any Grid Code changes that are progressed.

6.8 Impact on other industry documents

6.8.1 The proposed modification does not impact on any other industry documents

6.9 Implementation

6.9.1 The Workgroup proposes that, should the proposals be taken forward, the proposed changes be implemented 10 business days after an Authority decision. It is recognised that whilst the proposed changes may be implemented 10 business days after an Authority decision, the requirements are only applicable from a 'go-live' date to be defined in the proposed changes.

7 Workgroup Recommendations

7.1.1 The Workgroup recommends that:

(i) A mandatory 5 second 'rapid' frequency response requirement is developed for asynchronous generators (including HVDC Converters) required to provide frequency response. This development should take into account costs of implementation and the benefits in reduced curtailment of generation from renewable sources and other balancing costs. This work will continue under the Grid Code.

(ii) The clarity of the frequency response commencement and delivery profiles from synchronous generating plant should be improved. This work will continue under the Grid Code.

(iii) The existing CUSC-based remuneration mechanism for mandatory frequency response is developed to accommodate the rapid frequency response service from asynchronous plant (including HVDC Converters) and the additional clarity around frequency response commencement and delivery.

(iv) The existing commercial frequency response arrangements are further developed to provide a weekly Firm Frequency Response (FFR) tender and accommodate a rapid frequency response product that will be available to both generation (both asynchronous and synchronous) and demand providers ahead of the mandatory rapid frequency response requirement for asynchronous generators (including HVDC Converters).

7.1.2 It is proposed that National Grid begins development of proposals for items (iii) and (iv) to better understand the likely impact of changes and how existing systems could accommodate the changes. Following development of these proposals, they will then be brought to the Balancing Services Standing Group (BSSG) and Commercial Balancing Services Group (CBSG) for further discussion and development (subject to CUSC Panel approval).

Grid Code Frequency Response Working Group

Terms of Reference

It was agreed at May 2008 Grid Code Review Panel (GCRP) to establish a joint Grid Code and BSSG (Balancing Service Standing Group) Working Group. The Working Group would be tasked with reviewing the technical requirements and commercial mechanism applicable to the provision of frequency response, given the current generation mix and the anticipated changes in generation technologies.

Objectives
The Working Group will:

i. examine the appropriateness of the existing Grid Code obligations and commercial mechanism for frequency response to the current and predicted future generation mix – including offshore generation;

ii. identify feasible options that will maintain the security of the National Electricity Transmission System following frequency deviations (inclusive of islanding scenarios), taking account of the characteristics of the current and next generation of power stations e.g. nuclear, supercritical coal, wind etc and the potential for demand management;

iii. identify and quantify the advantages and disadvantages of each option;

iv. identify all the impacts of each option on the Grid Code, CUSC and any other associated documents within the framework;

v. agree and recommend a preferred option;

vi. draft any text modifications necessary to implement the recommendation;

vii. monitor the progress of the National Electricity Transmission System SQSS review and take into account any impact on the frequency reserve holding requirement arising from its recommendations.

viii. consider frequency response provisions of any other comparable electricity networks worldwide

ix. Consider the interaction with the ongoing development of the European Network Codes.

Governance
The Working Group has been convened and will operate and be managed under the remit of the Grid Code governance framework.

Annex 1 provides an illustrative overview of the applicable amendments process for both the Grid Code and BSSG (which follows the CUSC governance framework).

Membership
The membership of the working group will be drawn from the GCRP or their nominated representatives, the BSSG and the Authority.

Deliverables
The Working Group will produce a report outlining its analysis, findings and recommendations which will be submitted to the GCRP, BSSG and CUSC Amendments Panel. A copy of the report should also be submitted to the Electricity Balancing System Group (EBSG).

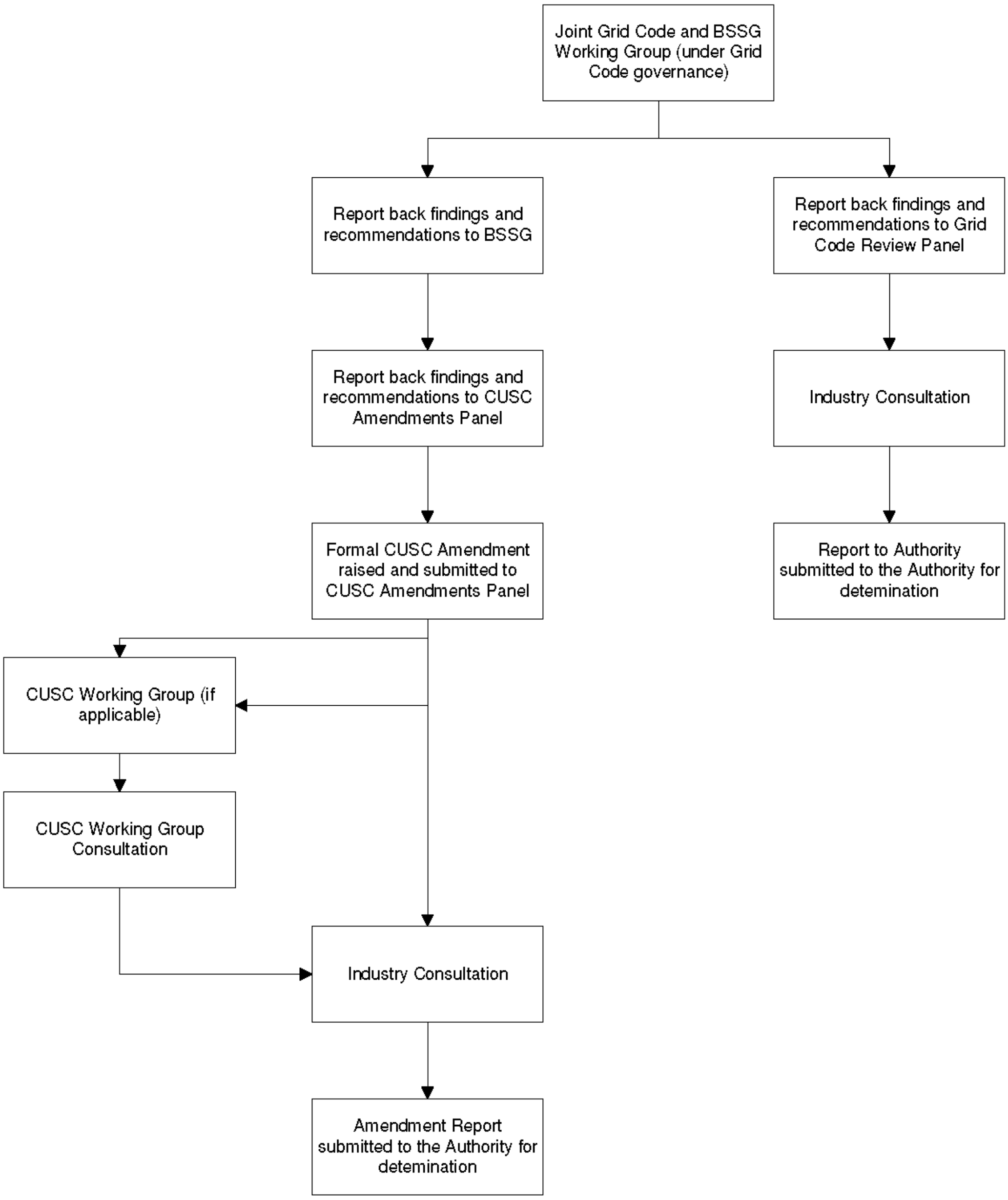
Timescales
The Working Group will present an Initial Conclusions Report to both the January 2012 GCRP and CUSC Panel meetings which will include:

- The findings and conclusions of the Technical Sub Group;
- A summary of the discussions and findings of the Working Group to date;
- Analysis of the options considered (technical and commercial) by the Working Group including those discounted;
- The Working Group preferred option(s) and relevant rationale.
- Detailed recommendations, which may include options, for the necessary further actions required to conclude the issue.

These Initial Conclusions will also be presented at the equivalent meeting of the BSSG.

Appropriate Final deliverables and associated timescales, will be agreed at the Jan 2012 GCRP meeting and Jan 2012 CUSC meeting.

Annex 1 – Working Group Governance Arrangements: Flow Chart



Annex 2 - FR Technical Subgroup Terms of Reference

Grid Code Frequency Response Technical Sub Group

Terms of Reference – dated November 2010

It was agreed at the 14th Frequency Response Working Group meeting to establish a Technical Sub Group. The Technical Sub Group would be tasked with assessing the volume of Frequency Response and inertial requirement for the transmission network.

Objectives

The Technical Sub Group will:

(i) determine the total volume of Transmission System Frequency Response and Synthetic Inertial requirements;

(ii) consider a largest secured loss of both 1320MW and 1800MW for the scenarios described in i) above; and

(iii) work on the initial assumption is that obligations are mandatory and equal.

Membership

Membership will be invited from relevant manufacturers, National Grid, Generators and a representative will be requested from the DCRP.

Deliverables and timescales

Three meetings are anticipated. The Technical Sub Group will produce a technical report outlining its analysis, findings and recommendations which will be submitted to the Frequency Response Working Group by the end of February 2011. This will allow the Frequency Response Working Group to report to the September 2011 meeting.

Annex 3 - Workgroup Consultation Responses

The following table provides a list of the responses received to the Frequency Response Workgroup Consultation. A summary of respondents support for the various proposals and copies of the full responses can be found in this annex.

Reference	Company
FR-CR-01	E.ON UK
FR-CR-02	EDF Energy
FR -CR-03	GDF Suez
FR -CR-04	SP Renewables
FR -CR-05	Open Energi
FR -CR-06	InterGen UK
FR -CR-07	RWE Supply &Trading
FR -CR-08	Russell Power
FR -CR-09	SSE Generation

Response Summary

	Technical Options		Commercial Options							
Company	Rapid Primary Response (asynchronous)	Ramping Clarity (synchronous)	Option A (Tradable)	Option B (Shared onsite)	Option C (Portfolio)	Option D (Technology specific)	Option E (MFR/ incentives)	Option F (SO provides)	Option G (Day Ahead Auction)	Option H (Supplier Req.)
E.ON UK	Unsupportive	Supportive	Unsupportive	Unsupportive	Unsupportive	Unsupportive	Unsupportive	Merits Further Investigation	Merits Further Investigation	Unsupportive
EDF Energy	Supportive	Supportive	Merits Further Investigation	Merits Further Investigation	Unsupportive	Merits Further Investigation	Unsupportive	Merits Further Investigation	Merits Further Investigation	Unsupportive
GDF Suez	Unsupportive	Unsupportive	Merits Further Investigation	Merits Further Investigation	Unsupportive	Merits Further Investigation	Merits Further Investigation	Merits Further Investigation	Unsupportive	Unsupportive
SP Renewables	Supportive	Supportive	No Comment	Unsupportive	Unsupportive	Merits Further Investigation	Unsupportive	Merits Further Investigation	No Comment	No Comment
Open Energi	No Comment	No Comment	Unsupportive	No Comment	No Comment	No Comment	No Comment	No Comment	Merits Further Investigation	No Comment
InterGen UK	Supportive	Supportive	Unsupportive	Unsupportive	Unsupportive	Unsupportive	Merits Further Investigation	Unsupportive	Unsupportive	Unsupportive
RWE Supply &Trading	Unsupportive	Unsupportive	Merits Further Investigation	Merits Further Investigation	Unsupportive	Unsupportive	Merits Further Investigation	Unsupportive	Merits Further Investigation	Unsupportive
Russell Power	Unsupportive	Unsupportive	Merits Further Investigation	Unsupportive	Unsupportive	Unsupportive	Merits Further Investigation	Merits Further Investigation	Merits Further Investigation	Merits Further Investigation
SSE Generation	Supportive	Supportive	Merits Further Investigation	Unsupportive	Merits Further Investigation	Unsupportive	Merits Further Investigation	Unsupportive	Merits Further Investigation	Unsupportive

Support Summary

	Technical Options		Commercial Options							
	Rapid Primary Response (asynchronous)	Ramping Clarity (synchronous)	Option A (Tradable)	Option B (Shared onsite)	Option C (Portfolio)	Option D (Technology specific)	Option E (MFR/ incentives)	Option F (SO provides)	Option G (Day Ahead Auction)	Option H (Supplier Req.)
Supportive / Merits Further Investigation	4	5	5	3	1	3	5	5	6	1
Unsupportive	4	3	3	5	7	5	3	3	2	6
No Comment	1	1	1	1	1	1	1	1	1	2

Frequency Response

Industry parties are invited to respond to this Workgroup Consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **30 October 2012** to Grid.Code@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

General Questions

Respondent:	*Guy Phillips, (guy.phillips@eon-uk.com)*
Company Name:	*E.ON UK*
Do you have any other comments?	Given the length of time that the working group has been running for, aside from the original terms of reference for the group, the drivers for the changes and an understanding of the importance of the change has perhaps been lost. It is not clear if there is a future tipping point in time where the system needs the support of the Faster Frequency Response capability and, secondly, that industry is seeking a change to the method by which frequency response is delivered and paid for. It would perhaps be worth reflecting on these points before progressing any future proposals. In any event any new proposals will need to be compatible with any interactions with the Electricity Balancing Significant Code Review, Electricity Market Reform and the European Network Code on Electricity Balancing.

Workgroup Questions

Consultation Question 1: Do you agree with the recommendations of the Frequency Response Technical Subgroup? • Requirement for Faster Frequency Response on asynchronous plant? • Clearer Primary Response Requirements for synchronous plant?	• Although we welcome the analysis undertaken by the Working Group, we do not believe the case for a requirement for Faster Frequency Response from asynchronous plant is sufficiently proven, particularly given the level of reliance on the capability in the assessment work. The Working Group consultation acknowledges that there is little actual experience of the provision of response from wind generation, curtailing wind generation to provide response is inevitably dependent on the wind resource being available at the point when the increase in output is required to deliver the frequency response service. The costs and benefits of having this capability should be fully articulated before determining an appropriate way forward and we agree with the recommendation in the consultation in this regard. A new minimum capability requirement may be unduly onerous and that capability could be provided by those willing to do so where their costs are recovered through commercial mechanisms, to provide a suitable framework to make the necessary investment. • We think there is merit in clarifying the requirements in the Grid Code in relation to the delay in provision of response following the initial instruction, particularly with the potential future requirement specified in the draft Requirements for Generators (RfG) European Network Code. Assuming the RfG Code is introduced, we do not think the more onerous 1s delay proposal has been justified and may not be technically feasible.
Consultation Question 2: Are there any impacts for generator owners that you would like to identify in relation to the recommendations? (e.g. costs, timescales, feasibility)	Inevitably more onerous requirements will lead to additional costs on generators which will feed through to the cost of energy.
Consultation Question 3: Are there any impacts for HVDC Converter owners that you would like to identify in relation to the recommendations? (e.g. costs, timescales, feasibility)	We have no comments in response to this question.
Consultation Question 4: Are there any impacts for manufacturers that you would like to identify in relation to the recommendations? (e.g. costs, timescales, feasibility)	There will need to be appropriate research and development in to new control equipment and associated software. This will have a lead time to deliver, alongside any subsequent implementation timescales. This should be considered as part of any implementation arrangements.
Consultation Question 5: Are there any additional comments you would like to make in relation to the frequency response technical requirements section of the consultation?	We have no comments at this time.

Consultation Question 6: Do you believe that Option A merits further investigation by the Workgroup? Please include your rationale.	Not at this time given the significant level of change that would need to be managed in order to implement any new arrangements. It may also not be technically achievable to meet a required level from different providers' capabilities.
Consultation Question 7: Is there anything additional you wish to note regarding Option A?	No.
Consultation Question 8: Do you believe that Option B merits further investigation by the Workgroup? Please include your rationale.	Not at this time as this would require a significant level of change to implement that may outweigh any benefits.
Consultation Question 9: Is there anything additional you wish to note regarding Option B?	No.
Consultation Question 10: Do you believe that Option C merits further investigation by the Workgroup? Please include your rationale.	No, as this only benefits a limited number of market participants.
Consultation Question 11: Is there anything additional you wish to note regarding Option C?	No.
Consultation Question 12: Do you believe that Option D merits further investigation by the Workgroup? Please include your rationale.	Not at this time, it is not clear that varying technical obligations would enable sufficient response to be available to the system operator under any given scenario.
Consultation Question 13: Is there anything additional you wish to note regarding Option D?	No.
Consultation Question 14: Do you believe that Option E merits further investigation by the Workgroup? Please include your rationale.	No, as we do not see what benefits an incentive regime would have above the current arrangements.
Consultation Question 15: Is there anything additional you wish to note regarding Option E?	No.
Consultation Question 16: Do you believe that Option F merits further investigation by the Workgroup? Please include your rationale.	Yes, we believe this has some merit in developing in further detail as this is a move towards a more commercial based service.
Consultation Question 17: Is there anything additional you wish to note regarding Option F?	We would not support arrangements which would enable the system operator to develop and own frequency response equipment. This would be akin to the Reactive Power arrangements and undermines the development of any market or commercial based service.
Consultation Question 18: Do you believe that Option G merits further investigation by the Workgroup? Please include your rationale.	Yes, we believe this has some merit in developing in further detail as this would facilitate a market based approach from all providers, excluding the system operator.

Consultation Question 19: Is there anything additional you wish to note regarding Option G?	A more incremental approach could be considered, initially with week ahead auctions and move to day ahead once IT and experience is gained from a week ahead basis. This may be more an evolution of the FFR service but to capture all forms of frequency response provision.
Consultation Question 20: Do you believe that Option H merits further investigation by the Workgroup? Please include your rationale.	We do not think this approach on its own is sufficient and do not believe it should be progressed further at this time.
Consultation Question 21: Is there anything additional you wish to note regarding Option H?	A subset of Option H could form part of Option G, where by suppliers and/or aggregators bid in to an auction along side other market participants. This may be more a development of the FFR arrangements and provide solutions to the issues outlined in relation to embedded generation, as well as demand side response.
Consultation Question 22: Are you aware of any element of the ENCs that would prevent the progression of the any of the technical requirements?	Not at this time however it should be noted that the ENC's are not yet agreed and in law.
Consultation Question 23: Are you aware of any element of the ENCs that would prevent the progression of the any of the commercial arrangements?	Not at this time, however the drafting of the Balancing Code is expected to commence towards the end of 2012/early 2013 and this may in turn inform any future commercial arrangements for frequency response services.

Grid Code Industry Response Proforma

Frequency Response

Industry parties are invited to respond to this Workgroup Consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **30 October 2012** to Grid.Code@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

General Questions

Respondent:	*John Costa*
Company Name:	*EDF Energy*
Do you have any other comments?	It is important to maintain a stable and reliable system through adequate Frequency Response provision. Failure to do so could create further disturbances across the Grid from the future issues identified in the consultation. We believe the obligations that currently exist are sufficient and that any proposals to increase or change the obligation should consider the most economic and practicable solutions. Clarity over how an obligation on delivery rather than capability would work would be useful. Clarity over which plant new arrangements would apply to would also be useful. We agree with the consultation that any new regime introduced as a result of this review should not apply to existing plant that cannot comply with Mandatory Frequency Response (MFR). Consideration of investment lead times is also important to ensure that signals to invest are clear and that sufficient time is allowed for market participants to be able to respond. Finally, any proposal emanating from this work should be aligned with the requirements of the EU Codes. We note that the consultation only mentions the Requirement for Generators (RfG) code, which is a key code, however there are other EU codes such as Operation Security, Demand Connection Code, Load Frequency and Balancing codes which all refer to Frequency requirements. Fundamentally, the RfG may make many of the options redundant where Frequency Response obligation is being traded or transferred from other sites. The RfG specifically states FR should be at the generator level. A closer review of the RfG and other codes as stated is needed to understand which proposals can be taken forward and which are constrained by the EU Codes which are legally binding on Member States.

Workgroup Questions

Consultation Question 1: Do you agree with the recommendations of the Frequency Response Technical Subgroup? • Requirement for Faster Frequency Response on asynchronous plant? • Clearer Primary Response Requirements for synchronous plant?	EDF Energy has participated in this Technical Subgroup and broadly agrees with its recommendations.
Consultation Question 2: Are there any impacts for generator owners that you would like to identify in relation to the recommendations? (e.g. costs, timescales, feasibility)	Yes. Implementing Frequency Response on a Wind Plant for example changes the operating philosophy and the primary benefit of this type of facility vis-à-vis the owner. The vast majority of wind farms are stand-alone generators, un-manned, and un-supervised. This philosophy would need to change requiring changes not only in equipment but company strategy, training, etc. Early implementation of similar technologies have hinted that there may be increased wear and tear caused by offering inertia based Frequency Control. Also, telecommunications networks used by wind farms are not generally designed to offer fast read/write capabilities and SCADA systems are generally not designed to support a 5s response. We would therefore disagree with the responses from the manufacturers who were polled as we are not aware of a single inertia based frequency support system that can react in 4/5s. Updated systems are currently not being developed for earlier platforms.
Consultation Question 3: Are there any impacts for HVDC Converter owners that you would like to identify in relation to the recommendations? (e.g. costs, timescales, feasibility)	No
Consultation Question 4: Are there any impacts for manufacturers that you would like to identify in relation to the recommendations? (e.g. costs, timescales, feasibility)	Manufacturers of FR equipment need to be aware of new requirements as soon as practicable in order to be able to invest and redesign current equipment. We recognise that FR equipment is becoming more and more standardised across Europe and there is a risk that the GB requirements may not allow generators to comply going forward.

Consultation Question 5: Are there any additional comments you would like to make in relation to the frequency response technical requirements section of the consultation?	We recognise that much effort has been spent on modelling wind turbine frequency support using older DFIG Doubly Fed Induction Generators which are limited to provide frequency support. These older turbine generations are in our opinion, un-feasible to retrofit. It would be prudent to focus solely on full conversion wind turbines which can provide 4/5s frequency responses as configured. They can meet the 10% target and can do so with no additional wear and tear on the mechanical portions of the turbines, etc. In terms of EPRs (European Pressurised Reactors) these are designed to be flexible and provide ancillary services, including frequency response to a certain extent. However any future change in capability requirements regarding frequency response would be very difficult and costly to implement in an EPR and may invalidate the safety case.
Consultation Question 6: Do you believe that Option A merits further investigation by the Workgroup? Please include your rationale.	This option would see the current minimum Grid Code (GC) obligation on a Generator retained but the generator would be able to trade away provision of that capability to other plant if it had more or less than this minimum requirement. We believe there is merit in discussing this option further. There is a risk that this option may not maintain system security to current levels as it is accepting that some generators may have less than the minimum 10%. What happens if all generators count on the others to build MFR capable plants to buy capability from? It is not clear what the "minimum requirement" would be and if it was higher or lower than the MFR in the Grid Code. It is also not clear from this option where the obligation would lie, whether it is on capability or delivery? Clarification on this point would be useful and if on delivery then how would this work with a competitive market. Would a generator be forced to deliver it or would it be based on price order? We agree that it should be opened up to demand-side providers however this may be difficult to meter as the workgroup notes.
Consultation Question 7: Is there anything additional you wish to note regarding Option A?	No.

Consultation Question 8: Do you believe that Option B merits further investigation by the Workgroup? Please include your rationale.	Option B would see a minimum GC obligation maintained similar to Option A but generators would be able to meet any shortfall in capability through the use of on-site alternatives such as flywheels/ batteries etc. We agree this option has merit and is similar to Option A. However it is not clear why the use of alternative technologies has to be limited to “on-site. (Fly wheels are mentioned but can these be on-site??). The cost of providing extra “on-site” equipment could be higher than procuring it from elsewhere as allowed under Option A. We also agree with the workgroup that if, for example, storage based technology was used, then this could be used to smooth out intermittent generation reducing BSUoS costs rather than for MRF. In all options the least cost and most practicable solution should be sought.
Consultation Question 9: Is there anything additional you wish to note regarding Option B?	The "on-site" aspect of the requirement can be difficult to define. An alternative could be to have a requirement of having a MFR capability available from the commissioning date of the plant, not necessarily on-site, but exclusive to the plant, that is not tradable. We agree that this option guaranties that the system has enough MFR capability at all times.
Consultation Question 10: Do you believe that Option C merits further investigation by the Workgroup? Please include your rationale.	Option C would see a minimum capacity obligation based on a company’s portfolio. We agree with the workgroup’s recommendation that Option C offers little discernable benefit over other options (and is included with option A) and agree that there is little merit in developing this further.
Consultation Question 11: Is there anything additional you wish to note regarding Option C?	It is not clear what point in time the obligation would bite as portfolios change from year to year and therefore the level of obligation could also. Would this be a moving target for instance and how often would it be reviewed?
Consultation Question 12: Do you believe that Option D merits further investigation by the Workgroup? Please include your rationale.	This option would obligate those generators who could provide more to offer more, thereby compensating generation that provided less than the 10% requirement. This could result in NG having the required amount of primary frequency response. We agree that it could be the most cost effective option as allowing each technology to provide a level of FR best suited to it would not require significantly higher investment costs. We therefore believe it has merit and should be discussed further.. It may though need to be coupled with other options to ensure sufficient MFR is maintained.
Consultation Question 13: Is there anything additional you wish to note regarding Option D?	No

Consultation Question 14: Do you believe that Option E merits further investigation by the Workgroup? Please include your rationale.	This option imposes a minimum capability obligation which is supported with incentives and would see a penalty and reward system based on whether installed capacity was above or below the 10% mandatory minimum requirement (MRF). We are not sure how this option would work with the market for providing FR. A generator who could provide the full 10% would be rewarded through the price it offered which should reflect market demand and therefore an extra incentive would not be needed. We therefore do not believe this option has merit as it is complex and may not work in practice.
Consultation Question 15: Is there anything additional you wish to note regarding Option E?	No
Consultation Question 16: Do you believe that Option F merits further investigation by the Workgroup? Please include your rationale.	This option would see the MFR removed from Generators and the System Operator would procure from providers or possibly develop and own frequency response equipment. We believe this centralised model has merit however we agree there may be issues with a single buyer setting both the target volume and procuring it. To avoid this monopsony problem it could work as an auction as per the next option G although clearly the minimum requirement level would need to be defined as an appropriate target.
Consultation Question 17: Is there anything additional you wish to note regarding Option F?	No
Consultation Question 18: Do you believe that Option G merits further investigation by the Workgroup? Please include your rationale.	This option would see a day-ahead auction from which the SO would procure the required level of FR for the next day. This could work with or without a MRF obligation and we believe there is merit in this. However there are some issues such as a) how would this fit in with investment lead times and b) how would NG guarantee it got all its requirements? This option would need to work alongside another option.
Consultation Question 19: Is there anything additional you wish to note regarding Option G?	No

Consultation Question 20: Do you believe that Option H merits further investigation by the Workgroup? Please include your rationale.	This option would see a MFR obligation set for each supplier based on their demand requirements which could be met via procurement of frequency response, or provision of demand management, stated in section 10.6 as being dependent on smart meters. We feel that the consultation text reflects some confusion within this area. Demand side response is a term best used to describe shifting of consumption through time by entire half-hours. Smart meters measure integrated half-hourly consumption, and can detect/measure demand side response of this nature. However, demand side response of this nature has absolutely nothing to do with frequency response, which if it is to be viewed as a form of demand side response, is delivered on incomparably-fast timescales of seconds, with, it can be reliably stated, no net effect on an appliance's, customer's, or Supplier's consumption across a half hour. EDF Energy does not favour such an obligation on Suppliers. EDF Energy has, however, recently responded to the EU Demand Connection Code, which has some relevance, as it could provide up to 800 MW of fast frequency extra response, building up over time, from domestic fridges. In our response, we made clear that we would support universal mandation, for domestic fridges only, of frequency response technology. This is subject to a suitable dead-band to avoid excess compressor cycling. This would have a positive cost-benefit, and is quite unlikely to come about in the absence of some form of mandation. The draft Demand Connection Code does not propose to obligate Suppliers in this respect. Rather, the delivery route for this code appears to be via EU appliance standards. We did not support, in our response, mandation for commercial fridges or other chillers, which the code allows for, as here there is a clear scope for a market approach
Consultation Question 21: Is there anything additional you wish to note regarding Option H?	No

Consultation Question 22: Are you aware of any element of the ENCs that would prevent the progression of the any of the technical requirements?	Yes, the EU RfG code defines firm frequency response capability requirements for individual type C and D Power Generating Modules. It does not allow mutualisation of capabilities among different plants - leading to having some plants which don't fulfil the requirements and others which are capable of more than the requirement - as proposed in this report. Therefore, the EU RfG code allows trading of actual frequency response ancillary services supply requirements, but it forbids trading of technical frequency response capability as proposed in this report. The other EU codes for Demand Connection, which may require the mandation of FR from Fridges, and the Operational Security, Balancing and Load Frequency, will need careful review to ensure these proposals are consistent with these codes.
Consultation Question 23: Are you aware of any element of the ENCs that would prevent the progression of the any of the commercial arrangements?	Yes, the RfG may prevent the options which allow MFR capability to be traded or transferred to another site/ provider as the RfG obligation clearly rest with the generator and doesn't foresee such a liberalised market. Closer review of these options with the RfG and other relevant codes (Demand Connection Code) is necessary to understand which options are viable and which may not be.

Simon Lord

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Summary

- Do not support either of the working group recommendations.
- Think that the following option have merit and should be explored further
    - Option B MFR obligation on a site specific basis
    - Option D MFR obligation technology specific could exclude certain technologies (CCS, Nuclear) from providing full capability
    - Option E allows providers to "pay a fixed amount" to not provide similar to D we support this.
    - Option F although this may be attractive some concern that given the lead time to build plant any short fall in requirement may be difficult to fill. The cost could change significantly as there would no longer be any requirement to build in the characteristics.
- We do not support any option that allows tradability/auctions that are not location specific.

Consultation Question 1: Do you agree with the recommendations of the Frequency Response Technical Subgroup?

No we do not

• Requirement for Faster Frequency Response on asynchronous plant?

This is unlikely to be a cost effective solution. The additional cost of installing this if it is technically possible on units will be far out weighted by simple re-despatch of the system on the very few occasions that the system is likely to be in a situation where additional response needed. The proposal has not considered the option of re-despatch.

• Clearer Primary Response Requirements for synchronous plant?

The primary response requirements for synchronous generators is clear, and it is based on the physical characterises of the various types of generation units on the system. This proposal seeks to impose a new definition that is more suitable for system response characterises but fails to take account of the physical characteristics of generators. We do not support any change in this area. Any change to definition must be based on physical machine characteristics

***Consultation Question 2*:** Are there any impacts for generator owners that you would like to identify in relation to the recommendations? (e.g. costs, timescales, feasibility)

Significant cost to install faster response with little opportunity to recover any additional cost as it is unlikely to be ever utilised.

***Consultation Question 6*:** Do you believe that Option A merits further investigation by the Workgroup? Please include your rationale.

This seems attractive but contractually it may be difficult to achieve. If a provider trades with another provider and does not build FR there is always the possibility that when the trade comes to the end there may not be additional providers to trade with so there would need to be a default price payable should the provider not trade and not provide the response. The trade could also be with a provider much higher up the merit order the cost of accessing the traded FR would be high.

Consultation Question 8: Do you believe that Option B merits further investigation by the Workgroup? Please include your rationale.

This seems more possible than A as it is likely that the response would be in the physical same area from the same plant type this. A provider could build two units one with twice the FR of the other, as long as both were available at the same time the same quantity of FR would be offered. Again issues with availably may be difficult to avoid.

Consultation Question 10: Do you believe that Option C merits further investigation by the Workgroup? Please include your rationale.

No we do not believe that any option that ignores physical location would be suitable.

Consultation Question 12: Do you believe that Option D merits further investigation by the Workgroup? Please include your rationale.

This option should be explored further low carbon technologies do not in general lend themselves to FR provision either due to the de-load cost or the technical requirement to run base load. Allowing this type of technology to have a lower/no requirement would appear to be a cost effective solution.

Consultation Question 14: Do you believe that Option E merits further investigation by the Workgroup? Please include your rationale.

This again has merit , in this situation CCS would pay an additional monthly “tariff” set as a pre estimate of the cost of procuring additional capability from other generators. The income would be spread over all providers who provide FR capability. This would allow providers to choose if it is cost effect to provide FR based on their technologies.

Consultation Question 16: Do you believe that Option F merits further investigation by the Workgroup? Please include your rationale.

This has some merit in that providers of new technology (CCS etc) that are not suited to providing response and are unlikely to the used would not need to provide additional units/ systems to meet the mandatory requirement. The market price would likely need to change to incentivise providers to build the characterises into new plant. It is unclear given the lead time to build if this type of arrangement would work

Consultation Question 18: Do you believe that Option G merits further investigation by the Workgroup? Please include your rationale.

The electricity market prime function is the delivery of energy adding a day-ahead FR auction would produce a sub optimal result. The market currently positions a number of units for FR by part loading, a tendered market would not allow the SO to take advantage of this. The interaction with constraints/location would be a difficult area for any auction. We do not support this option.

Consultation Question 20: Do you believe that Option H merits further investigation by the Workgroup? Please include your rationale.

This would not produce any benefits compared to the current system where the SO provides a coordinated approach to the

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Frequency Response

Industry parties are invited to respond to this Workgroup Consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **30 October 2012** to Grid.Code@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

General Questions

Respondent:	*Murray Rennie, Commercial Manager, 0131 624 6771*
Company Name:	*InterGen UK Ltd*
Do you have any other comments?	

Workgroup Questions

Consultation Question 1: Do you agree with the recommendations of the Frequency Response Technical Subgroup? • Requirement for Faster Frequency Response on asynchronous plant? • Clearer Primary Response Requirements for synchronous plant?	InterGen agrees with the Frequency Response Technical Subgroup that there is a requirement for faster frequency response on asynchronous plant. Intergen agrees that there is a requirement for clearer Primary Response requirements from synchronous plant.
Consultation Question 2: Are there any impacts for generator owners that you would like to identify in relation to the recommendations? (e.g. costs, timescales, feasibility)	InterGen believes that there will be additional costs placed upon generators to ensure clearer primary response requirements are available to NGC plus additional system costs as a result of increased costs for asynchronous generation.
Consultation Question 3: Are there any impacts for HVDC Converter owners that you would like to identify in relation to the recommendations? (e.g. costs, timescales, feasibility)	No comment
Consultation Question 4: Are there any impacts for manufacturers that you would like to identify in relation to the recommendations? (e.g. costs, timescales, feasibility)	No comment

Consultation Question 5: Are there any additional comments you would like to make in relation to the frequency response technical requirements section of the consultation?	Intergen has no additional comment to make.
Consultation Question 6: Do you believe that Option A merits further investigation by the Workgroup? Please include your rationale.	InterGen believes that Option A merits no further investigation. As an independent generator Intergen believes that the capital costs required would outweigh any benefits.
Consultation Question 7: Is there anything additional you wish to note regarding Option A?	Intergen believes that there would increased operating and BSuos costs and increased operational complexity as a result of implementing Option A.
Consultation Question 8: Do you believe that Option B merits further investigation by the Workgroup? Please include your rationale.	Intergen believes that Option B merits no further investigation. The capital costs required for alternative on-site technology will be prohibitive and there will be operational risk associated with the alternative technologies.
Consultation Question 9: Is there anything additional you wish to note regarding Option B?	No comment.
Consultation Question 10: Do you believe that Option C merits further investigation by the Workgroup? Please include your rationale.	Intergen agees with the Workgroup that Option C merits no further investigation. InterGen believes that Option C would have benefitted Generators with a large portfolio of differing fuel types.
Consultation Question 11: Is there anything additional you wish to note regarding Option C?	No Comment.
Consultation Question 12: Do you believe that Option D merits further investigation by the Workgroup? Please include your rationale.	Intergen agrees with the Workgroup that Option D merits no further investigation primarily due to potential increases in BSuoS charges and the potential for the System Operator to be forced to take less economic FR actions due to the generation mix available on a particular day.
Consultation Question 13: Is there anything additional you wish to note regarding Option D?	No Comment.
Consultation Question 14: Do you believe that Option E merits further investigation by the Workgroup? Please include your rationale.	Intergen agrees with the Workgroup that option E does not merit further investigation at this moment.
Consultation Question 15: Is there anything additional you wish to note regarding Option E?	Intergen agrees with the workgroup that this solution may be a more beneficial solution for some generators to pay an additional cost rather than the capital cost of new investment.
Consultation Question 16: Do you believe that Option F merits further investigation by the Workgroup? Please include your rationale.	Intergen agrees with the Workgroup that option F does not merit further investigation. We believe that the increased costs and complexity required by this option would be spread across the industry whilst the possibility exists that not all fuels types may benefit.

Consultation Question 17: Is there anything additional you wish to note regarding Option F?	No additional comments.
Consultation Question 18: Do you believe that Option G merits further investigation by the Workgroup? Please include your rationale.	Intergen believes that Option G does not merit further investigation. Intergen believes that any form of day-ahead auction will add an unnecessary extra level of complexity. We believe that there will also be additional costs in setting up an auction system. We also believe that there will still be a requirement for the SO to manage any WD changes as units selected in the auction may fail to deliver on the day.
Consultation Question 19: Is there anything additional you wish to note regarding Option G?	No comment.
Consultation Question 20: Do you believe that Option H merits further investigation by the Workgroup? Please include your rationale.	InterGen agrees with the Workgroup that Option H does not merit further investigation at this time as the infrastructure required under this option is not available at this moment in time.
Consultation Question 21: Is there anything additional you wish to note regarding Option H?	No additional comment.
Consultation Question 22: Are you aware of any element of the ENCs that would prevent the progression of the any of the technical requirements?	Intergen are not aware of any element of the ENCs that would prevent the progression of any of the technical requirements
Consultation Question 23: Are you aware of any element of the ENCs that would prevent the progression of the any of the commercial arrangements?	Intergen are not aware of any element of the ENCs that would prevent the progression of any of the commercial arrangements.

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Frequency Response

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General Questions

Respondent:	*Joe Warren, Commercial Manager* *joe.warren@openenergi.com* +44 (0) 20 3051 0608
Company Name:	*Open Energi*
Do you have any other comments?	Open Energi recognise and appreciate the significant work which National Grid have done in opening up the frequency response market to demand side participants through the Firm Frequency Response mechanism. We believe that some additional steps could further facilitate market access for frequency response for new technologies, specifically, establishing access for all players to a day-ahead market. Regardless of which option is ultimately chosen regarding the Mandatory Frequency Response arrangements, we believe steps to facilitate participation of the demand side would be beneficial in terms of increasing security of supply, reducing costs and benefiting the environment.

Workgroup Questions

Consultation Question 1: Do you agree with the recommendations of the Frequency Response Technical Subgroup? • Requirement for Faster Frequency Response on asynchronous plant? • Clearer Primary Response Requirements for synchronous plant?	
Consultation Question 2: Are there any impacts for generator owners that you would like to identify in relation to the recommendations? (e.g. costs, timescales, feasibility)	

Consultation Question 3: Are there any impacts for HVDC Converter owners that you would like to identify in relation to the recommendations? (e.g. costs, timescales, feasibility)	
Consultation Question 4: Are there any impacts for manufacturers that you would like to identify in relation to the recommendations? (e.g. costs, timescales, feasibility)	
Consultation Question 5: Are there any additional comments you would like to make in relation to the frequency response technical requirements section of the consultation?	
Consultation Question 6: Do you believe that Option A merits further investigation by the Workgroup? Please include your rationale.	
Consultation Question 7: Is there anything additional you wish to note regarding Option A?	While we do not think Option A is the best option, if Option A were pursued we believe that generators should have the option to contract with either generation or demand side providers to provide frequency response capability.
Consultation Question 8: Do you believe that Option B merits further investigation by the Workgroup? Please include your rationale.	
Consultation Question 9: Is there anything additional you wish to note regarding Option B?	
Consultation Question 10: Do you believe that Option C merits further investigation by the Workgroup? Please include your rationale.	
Consultation Question 11: Is there anything additional you wish to note regarding Option C?	
Consultation Question 12: Do you believe that Option D merits further investigation by the Workgroup? Please include your rationale.	
Consultation Question 13: Is there anything additional you wish to note regarding Option D?	
Consultation Question 14: Do you believe that Option E merits further investigation by the Workgroup? Please include your rationale.	

Consultation Question 15: Is there anything additional you wish to note regarding Option E?	
Consultation Question 16: Do you believe that Option F merits further investigation by the Workgroup? Please include your rationale.	
Consultation Question 17: Is there anything additional you wish to note regarding Option F?	
Consultation Question 18: Do you believe that Option G merits further investigation by the Workgroup? Please include your rationale.	This option has benefits in facilitating market access for demand side participants. We recognise the work which National Grid has done in facilitating access to the demand side through the FFR framework. In comparison to FFR, this Option G has some additional advantages in facilitating access under certain circumstances. In particular, it would be easier for demand side players to submit tenders day ahead, when the likely demand outturn is easier to forecast, in comparison to FFR where demand must be forecast 1-2 months ahead.
Consultation Question 19: Is there anything additional you wish to note regarding Option G?	We would support any option which builds on the significant work which has been done to facilitate access from demand side providers and other market entrants through FFR. If a day-ahead market is established we would recommend that this is in addition to, rather than instead of, existing longer period FFR market arrangements. Longer term (>=1 month) tenders have some advantages both in managing frequency response costs and in providing an investment signal. Therefore we believe it will be beneficial for all providers to be able to tender in either or both day-ahead and existing FFR timescales and durations if a day-ahead market is established.
Consultation Question 20: Do you believe that Option H merits further investigation by the Workgroup? Please include your rationale.	
Consultation Question 21: Is there anything additional you wish to note regarding Option H?	
Consultation Question 22: Are you aware of any element of the ENCs that would prevent the progression of the any of the technical requirements?	
Consultation Question 23: Are you aware of any element of the ENCs that would prevent the progression of the any of the commercial arrangements?	

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Frequency Response

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General Questions

Respondent:	*Tim Russell tim@russellpower.co.uk 01793 751369*
Company Name:	*RussellPower Limited*
Do you have any other comments?	I will confine my substantive comments almost entirely to the purely technical and in particular: • How you have modelled future system inertia and especially the inertia of demand • What work if any has been done recently to establish a value for demand inertia • The notion of derivative frequency response as synthetic inertia • The relationship between system inertia and speed of primary response • The availability of fast proportional frequency response The modelling of demand inertia There is no reference in the report and in particular the technical subgroup report as to how demand inertia has been modelled. There is always a tendency for people to confuse the inertia of demand with the frequency sensitivity of demand. Both of course tend to arise from rotating (or generally moving) demand as opposed to demand not associated with mechanical movement but the inertia has the same effect as the inertia of generation and is purely related to rotating (or otherwise moving) mass and affects the rate of change of frequency. The frequency sensitivity of demand is purely the effect that for some demand a lower frequency results is a lower demand in the steady state. It is analogous to the effect of frequency on the output of a single shaft CCGT (ignoring any control systems installed to ensure compliance with CC6.3.3 of course). Paragraph 4.4 of the technical report may refer to demand inertia though that is not clear. What is meant by damping? Genuine demand inertia is the same as generation inertia and should be modelled identically as part of the overall system

	inertia. It is not clear from figure 4.1 of the technical report how the total system inertia (comprising the inertia of both generation and demand) has been modelled. The importance of demand inertia is best described in the seminal 1974 IEE Paper "Power System model for large frequency disturbances" (Proc IEE Vol 121 7th July 1974 by Ashmole Battlebury and Bowdler). It describes the system tests undertaken in 1967 splitting the system in two at Cellarhead and observing the frequency behaviour of the resulting sections of system one of which had a deficit of generation. The key observation is in section 3.2 quoted below. *"Figure 5 shows the calculated rates plotted against the measured rates of change of frequency. From this it can be seen that the calculated rates are higher by approximately a factor of two than the measured rates; that is, the effective inertia of the system is considerably higher than the estimated total physical inertia. Fig. 6 shows that good agreement between measured and calculated system-frequency transients can be obtained only be assuming the effective system inertia is twice the estimated physical inertia."* The estimated "total physical inertia" had been calculated "mainly with that associated with generators." In other words that showed that in 1967 **of the total system inertia only approximately half was made up of the inertia of generators. The other half was made of inertia of rotating (or otherwise physically moving) demand.** <u>What work has been undertaken recently to establish demand inertia?</u> Given the central importance of system inertia (comprising the sum of inertia provided by generation and demand) in the frequency behaviour of a power system there is surprisingly little reference in the technical report to any work that may have been undertaken recently to establish a value for either demand inertia or alternatively total system inertia (comprising the sum of demand and generation inertia). Has any such work been undertaken? Use could be made of frequency plots from any significant generation loss incidents and the system inertia calculated from the initial rate of fall in frequency and the generation loss. By subtracting the total inertia of all the generation known to be synchronised at the time from this calculated value, the value of demand inertia would be obtained. Clearly the value of demand inertia for any level of system demand may have changed since 1967 for example there is

proportionately less heavy industry. On the other hand do electrified railways (perhaps those with regenerative breaking) comprise inertia?

Whatever the current demand inertia is there should be some discussion of what it may be in the future. For example do heat pumps create inertia? Given that up to half the system inertia (it could be less but equally it could be more at times when much of the generation running has little or no inertia) is that of demand it seems important to investigate how this may be expected to change in the future.

<u>Description of derivative frequency response as "synthetic inertia"</u>

I find the description of frequency response that is proportional to the rate of change of frequency as "synthetic inertia" as misleading, unhelpful and potentially dangerous if a misguided engineer starts to model it as if it were inertia. The mathematical equivalence of a frequency response that is proportional to the rate of change of frequency is the same as that of inertia but it should be described as what it is i.e. "frequency response proportional to the rate of change of frequency".

Describing it as synthetic inertia is like somebody fitting a turbocharger to a car and describing that as synthetic (negative) mass. Alternatively fitting one could be described as synthetic positive mass. What they are actually doing is increasing or decreasing the torque of the engine which directly affects the car's acceleration. They are not creating positive or negative mass. In the same way rate of change of frequency driven frequency response is just that. It is not inertia. If you want the latter ask for flywheels to be installed.

<u>Total inertia and required speed of response delivery</u>

Whilst there may be some merit in frequency response that is proportional to the rate of change of frequency you have identified a disadvantage in terms of susceptibility to noise. You have in my view correctly concluded that if the system inertia is reduced what is needed is for the ordinary "proportional to frequency deviation" primary (and high frequency) response to be delivered in a shorter timescale.

It should be self evident that this is the case as the rate of change of frequency for a given sudden generation / demand mismatch is in inverse proportion to the system inertia so if the objective is to arrest the frequency rise or fall before a set frequency is reached than the speed of primary response

	delivery needs to be faster the lower the level of system inertia. It is for this reason that power systems that are significantly large the GB (the UCTE system for example) currently find it adequate to specify a primary response delivery time of 30 seconds, as opposed to 10 seconds in GB. Leaving aside the different size of system loss that they cater for the primary determinant of the slower required timescale is simply the larger inertia of the larger system. So for example if the total inertia on the UCTE system were to fall significantly they would have to specify primary response timescales of less than 30 seconds in order to maintain their existing quality of frequency control. Likewise in GB a lower inertia will require a faster delivery of primary response and if for any reason the inertia were to increase then the time taken for primary response to be delivered in could be increased. Times for frequency response delivery are generally determined my minimum inertia conditions which usually coincide with minimum demand. In theory the delivery of frequency response times could be allowed to vary throughout the load cycle in inverse proportion to the level of total system inertia. Note that it is sometimes stated that what is required for a lower level of system inertia is a higher amount of frequency response. This is not the case as inertia affects not the amount but the required time to deliver that amount. When it is stated that a higher amount is needed what is really being described is the effect delivering a higher amount in the same time has on the amount delivered at an earlier time. In other words if frequency response is delivered linearly over time and x MW is required in ten seconds but them the total inertia halves what will now be required is not 2x MW is 10 seconds but the same x MW but delivered in 5 seconds. 2x MW delivered in 10 seconds may fortuitously deliver x MW in 5 seconds but it is the latter that is actually the new requirement. <u>The availability of fast proportional frequency response</u> If lower system inertias in the future require primary frequency response to be delivered more quickly the good news is that for systems of the size of GB and larger there is a more than adequate amount of very fast proportional primary and high frequency response potentially available via dynamic frequency sensitive demand. Merely fitting all new domestic fridges and freezers in GB with a frequency sensitive controller could within a ten year period provide between 500MW and 1000MW of frequency response that delivers that primary and high

	frequency response in less than a second. It would be geographically dispersed and available at all times, indeed its availability would be highest during summer periods. Similar controllers fitted to commercial cooling and heating equipment could see the amount of extremely fast proportional frequency response available rise to more than is likely to be required in the foreseeable future. So although a fall in total system inertia in any system will require faster proportional primary and high frequency response, as far as GB is concerned the technical ability to provide very fast response already exists in sufficient quantity, although generators may not be the most economic means of fulfilling the requirement.

Workgroup Questions

Consultation Question 1: Do you agree with the recommendations of the Frequency Response Technical Subgroup? • Requirement for Faster Frequency Response on asynchronous plant? • Clearer Primary Response Requirements for synchronous plant?	No. It is axiomatic that a change in the value of total system inertia will require a change in delivery time for proportional primary frequency response (having dismissed the utility of frequency response proportional to the rate of change of frequency). So for example a fall in the value of system inertia requires primary frequency response to be delivered more quickly. There is no technical justification at all however for the faster frequency response being provided by any particular type of generation or indeed generation at all rather than demand for example. That is purely an economic issue and I would suggest that anything that deviates from delivering the faster response required in the most economic manner is probably a breach of the Electricity Act and Transmission License. If you are going to take a view that it is justifiable to say that generation with less inertia must provide faster frequency response then this should apply to all generation i.e. the speed of delivery of primary response should be related in some manner to the inertia of that generation. This is very unlikely to be the most economic solution so should not be pursued. Neither should placing a requirement on a particular type of generation that happens to have no inertia unless that happens to be the most economic solution which is extremely unlikely. That course of action makes as little sense as placing a requirement on all electric lighting and resistive heating demand to fit flywheels to create inertia to make up for the fact that the lighting and heating demand itself has no inertia.

Consultation Question 2: Are there any impacts for generator owners that you would like to identify in relation to the recommendations? (e.g. costs, timescales, feasibility)	N/a
Consultation Question 3: Are there any impacts for HVDC Converter owners that you would like to identify in relation to the recommendations? (e.g. costs, timescales, feasibility)	N/a
Consultation Question 4: Are there any impacts for manufacturers that you would like to identify in relation to the recommendations? (e.g. costs, timescales, feasibility)	N/a
Consultation Question 5: Are there any additional comments you would like to make in relation to the frequency response technical requirements section of the consultation?	All my comments have been made under other comments above.
Consultation Question 6: Do you believe that Option A merits further investigation by the Workgroup? Please include your rationale.	This is an improvement over the current position but still likely to be far from the minimum cost solution unless those obliged are permitted to purchase provision from the full range of providers i.e. both demand and generation sources of response.
Consultation Question 7: Is there anything additional you wish to note regarding Option A?	
Consultation Question 8: Do you believe that Option B merits further investigation by the Workgroup? Please include your rationale.	This will be a more expensive way of purchasing frequency response than option A.
Consultation Question 9: Is there anything additional you wish to note regarding Option B?	
Consultation Question 10: Do you believe that Option C merits further investigation by the Workgroup? Please include your rationale.	Apart from giving a systematic advantage to portfolio players this appears to have no merit (and the latter is only of merit to portfolio players).
Consultation Question 11: Is there anything additional you wish to note regarding Option C?	
Consultation Question 12: Do you believe that Option D merits further investigation by the Workgroup? Please include your rationale.	The only merit in this is that it would not force “unnatural” behaviour on particular plant types. It would of course not necessarily lead to the required total amount of frequency response being available.
Consultation Question 13: Is there anything additional you wish to note regarding Option D?	

Consultation Question 14: Do you believe that Option E merits further investigation by the Workgroup? Please include your rationale.	This has some merit but less than any options that leave anybody with an obligation free to purchase its fulfilment fro the cheapest source.
Consultation Question 15: Is there anything additional you wish to note regarding Option E?	
Consultation Question 16: Do you believe that Option F merits further investigation by the Workgroup? Please include your rationale.	Yes. This is likely to result in the lowest overall cost of obtaining the frequency response that is required.
Consultation Question 17: Is there anything additional you wish to note regarding Option F?	
Consultation Question 18: Do you believe that Option G merits further investigation by the Workgroup? Please include your rationale.	A day ahead auction could be a useful part of any of the frameworks for frequency response provision. It is important to note that participation in this auction should not be a condition of providing frequency response as some of the fastest and most economic providers are likely to be available only on a long term contract "fit and forget" basis.
Consultation Question 19: Is there anything additional you wish to note regarding Option G?	
Consultation Question 20: Do you believe that Option H merits further investigation by the Workgroup? Please include your rationale.	There is some merit in this as suppliers are likely to be proactive in seeking out demand side providers where these are more economic than fulfilling and obligation from a generator provider.
Consultation Question 21: Is there anything additional you wish to note regarding Option H?	
Consultation Question 22: Are you aware of any element of the ENCs that would prevent the progression of the any of the technical requirements?	No
Consultation Question 23: Are you aware of any element of the ENCs that would prevent the progression of the any of the commercial arrangements?	No

Grid Code Industry Response Proforma

Frequency Response

Industry parties are invited to respond to this Workgroup Consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **30 October 2012** to Grid.Code@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

General Questions

Respondent:	*Raoul Thulin, 01793 892634, raoul.thulin@rwe.com*
Company Name:	*RWE Supply & Trading*
Do you have any other comments?	The options outlined in the consultation document are primarily focused on technical capability rather than on operational efficiency and overall cost reduction. Whilst a number of the alternatives may ensure the availability of a particular level of response capability, the cost element is not given the same level of consideration. Thus, whilst some of the options may provide an efficient way of determining levels of capital spend, they could result in capability that is very expensive to utilise and may therefore not give the most cost effective solution to the anticipated system issues. We believe that through an efficient market mechanism, the correct investment signals can be given to ensure that the required levels of response capability are available to the system operator when required and at efficient utilisation prices. An overall solution should consider possible alternative solutions including sources of additional inertia, power storage to increase effective demand during times of low demand and high generation from renewables, demand-side load-shifting etc. etc..

Workgroup Questions

Consultation Question 1: Do you agree with the recommendations of the Frequency Response Technical Subgroup? • Requirement for Faster Frequency Response on asynchronous plant? • Clearer Primary Response Requirements for synchronous plant?	We consider that the case has still to be made that the proposals represent the most cost-effective way to manage the expected system conditions. At this time no cost related information has been provided and therefore it is not possible to assess the recommendations.

Consultation Question 2: Are there any impacts for generator owners that you would like to identify in relation to the recommendations? (e.g. costs, timescales, feasibility)	The anticipated costs of implementing the recommended changes must be established as there is currently no economic test being applied.
Consultation Question 3: Are there any impacts for HVDC Converter owners that you would like to identify in relation to the recommendations? (e.g. costs, timescales, feasibility)	None identified.
Consultation Question 4: Are there any impacts for manufacturers that you would like to identify in relation to the recommendations? (e.g. costs, timescales, feasibility)	None identified.
Consultation Question 5: Are there any additional comments you would like to make in relation to the frequency response technical requirements section of the consultation?	In order to develop a least-cost solution that meets the anticipated difficulties in managing the system under certain specific circumstances, the operating costs must be considered in more detail in combination with the technical requirements. The focus on technical needs may indicate minimum frequency response capabilities that could meet the system requirements but significantly more work would be required to determine the most cost effective solution.
Consultation Question 6: Do you believe that Option A merits further investigation by the Workgroup? Please include your rationale.	We believe that Option A could offer an economic test on whether or not to invest in frequency response capability at a particular site and could therefore provide an efficient way to secure capability on the system by providing cheaper alternative sources. Option A should therefore be investigated further.
Consultation Question 7: Is there anything additional you wish to note regarding Option A?	Whilst Option A might be an efficient way to secure capability, it is not necessarily the case that this would lead to a more efficient outcome in terms of the operation of the system as it does not favour capability that would be cost effective to utilise.
Consultation Question 8: Do you believe that Option B merits further investigation by the Workgroup? Please include your rationale.	As with Option A, Option B provides a means by which investments in capability can be made more efficient where economic alternative sources are available. This option should be investigated further.
Consultation Question 9: Is there anything additional you wish to note regarding Option B?	As with Option A, this may not result in an overall reduction in cost as no account is taken of the operational costs.
Consultation Question 10: Do you believe that Option C merits further investigation by the Workgroup? Please include your rationale.	Option C should not be investigated further as it does not provide any benefits beyond what options A and B may offer.
Consultation Question 11: Is there anything additional you wish to note regarding Option C?	No

Consultation Question 12: Do you believe that Option D merits further investigation by the Workgroup? Please include your rationale.	Option D could provide an effective way of ensuring cost effective investment in capability through requiring either the natural capability inherent in the technology (very low cost) or a level above the natural capability represented by a similar level of investment across different technologies. Thus, simplistically, any new build might be obliged to install a level of response capability achievable through a capital spend related to a certain percentage of the total build cost. This would be very difficult to determine equitably and would be open to challenge. Therefore, although the option has certain merits, we do not believe it to be a manageable solution and should therefore not be investigated further.
Consultation Question 13: Is there anything additional you wish to note regarding Option D?	No
Consultation Question 14: Do you believe that Option E merits further investigation by the Workgroup? Please include your rationale.	Option E is in effect a centrally administered version of Option A. As such, it merits further investigation.
Consultation Question 15: Is there anything additional you wish to note regarding Option E?	The same issues arise as with Option A in potentially rewarding capability that is uneconomic to utilise while at the same time penalising capability that may not fully meet the obligations but may be more cost-effective to use.
Consultation Question 16: Do you believe that Option F merits further investigation by the Workgroup? Please include your rationale.	We do not believe that Option F merits further investigation. The ability for the System Operator to develop and own frequency response equipment would stifle competition and would not lead to an efficient solution to the anticipated difficulties in managing the system.
Consultation Question 17: Is there anything additional you wish to note regarding Option F?	No
Consultation Question 18: Do you believe that Option G merits further investigation by the Workgroup? Please include your rationale.	A day ahead auction may address the possible occasional difficulties in ensuring that the right mix of plant is available at times of greatest system requirement. By procuring response in the same timescales as plant is being traded for energy, an efficient despatch solution may be achieved. We believe that Option G merits further consideration. This option is capable of providing correct signals both for investment in capability and for efficient dispatch in order to deliver that capability.
Consultation Question 19: Is there anything additional you wish to note regarding Option G?	It is likely that the system would still require the ability for the System Operator to procure response in near to real-time timescales. Therefore we do not consider Option G to be complete alternative to other commercial arrangements but may be appropriate for ensuring that an appropriate mix of plant is available on the day.
Consultation Question 20: Do you believe that Option H merits further investigation by the Workgroup? Please include your rationale.	An obligation on suppliers is unlikely to result in efficient procurement as the system requirement is dynamic and based on a number of criteria that the System Operator is best placed to assess. We do not believe that this option merits further investigation

Consultation Question 21: Is there anything additional you wish to note regarding Option H?	No
Consultation Question 22: Are you aware of any element of the ENCs that would prevent the progression of the any of the technical requirements?	No
Consultation Question 23: Are you aware of any element of the ENCs that would prevent the progression of the any of the commercial arrangements?	No

Grid Code Industry Response Proforma

Frequency Response

Industry parties are invited to respond to this Workgroup Consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **30 October 2012** to Grid.Code@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

General Questions

Respondent:	*Craig Bennoch (cbennoch@scottishpower.com)*
Company Name:	*Scottish Power Renewables*
Do you have any other comments?	

Workgroup Questions

Consultation Question 1: Do you agree with the recommendations of the Frequency Response Technical Subgroup? • Requirement for Faster Frequency Response on asynchronous plant? • Clearer Primary Response Requirements for synchronous plant?	The identified problem is evident, the solution is complex. Agree, if it is clear that different generator types will be able to cost effectively deliver the response.
Consultation Question 2: Are there any impacts for generator owners that you would like to identify in relation to the recommendations? (e.g. costs, timescales, feasibility)	Feasibility – What extra equipment is needed for renewable generators to meet any new requirements? Is it available now? Costs – Is any information available on how much this new equipment is going to cost? Will it have an effect on performance of wind turbines? Timescales – Will there be a gradual introduction of requirements? How is the EU grid code considered?
Consultation Question 3: Are there any impacts for HVDC Converter owners that you would like to identify in relation to the recommendations? (e.g. costs, timescales, feasibility)	Can working group review the impact on cost, timescales, and feasibility (technical)?
Consultation Question 4: Are there any impacts for manufacturers that you would like to identify in relation to the recommendations? (e.g. costs, timescales, feasibility)	As above.

Consultation Question 5: Are there any additional comments you would like to make in relation to the frequency response technical requirements section of the consultation?	No comment.
Consultation Question 6: Do you believe that Option A merits further investigation by the Workgroup? Please include your rationale.	All options have benefits and drawbacks. However, the solution should not prejudice any specific technology. The options should be presented against each other with cost valuations.
Consultation Question 7: Is there anything additional you wish to note regarding Option A?	There is no discussion of OFTO in this document. How would the various offshore regimes implement these requirements?
Consultation Question 8: Do you believe that Option B merits further investigation by the Workgroup? Please include your rationale.	I don't see how this would be practical for offshore wind? It seems that there would be unnecessary added complexity for O&M of the wind farm.
Consultation Question 9: Is there anything additional you wish to note regarding Option B?	What defines a shared site?
Consultation Question 10: Do you believe that Option C merits further investigation by the Workgroup? Please include your rationale.	Has this been reviewed against the current market, and who owns what generation assets?
Consultation Question 11: Is there anything additional you wish to note regarding Option C?	With this type of scheme, how would the case where there are joint ventures work?
Consultation Question 12: Do you believe that Option D merits further investigation by the Workgroup? Please include your rationale.	Yes, preferred option until commercial impact assessed.
Consultation Question 13: Is there anything additional you wish to note regarding Option D?	No comment.
Consultation Question 14: Do you believe that Option E merits further investigation by the Workgroup? Please include your rationale.	Seems complex to implement fairly.
Consultation Question 15: Is there anything additional you wish to note regarding Option E?	No comment.
Consultation Question 16: Do you believe that Option F merits further investigation by the Workgroup? Please include your rationale.	This might be a good approach and maintains parity for generators. Would OFTO assets be included in this?
Consultation Question 17: Is there anything additional you wish to note regarding Option F?	No comment.

Consultation Question 18: Do you believe that Option G merits further investigation by the Workgroup? Please include your rationale.	No comment.
Consultation Question 19: Is there anything additional you wish to note regarding Option G?	No comment.
Consultation Question 20: Do you believe that Option H merits further investigation by the Workgroup? Please include your rationale.	No comment.
Consultation Question 21: Is there anything additional you wish to note regarding Option H?	No comment.
Consultation Question 22: Are you aware of any element of the ENCs that would prevent the progression of the any of the technical requirements?	ENC generator requirements for frequency response are required for bands C and D. How would this affect generators with lots of small generation capacity (Band A and B), which may contribute to frequency response characteristics?
Consultation Question 23: Are you aware of any element of the ENCs that would prevent the progression of the any of the commercial arrangements?	Response is the same as in Q22 above.

Grid Code Industry Response Proforma

Frequency Response

Industry parties are invited to respond to this Workgroup Consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **30 October 2012** to Grid.Code@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

General Questions

Respondent:	Campbell McDonald, 01738 453424, 07767 852614, campbell.mcdonald@sse.com
Company Name:	SSE Generation Ltd, Keadby Generation Ltd, Medway Power Ltd, Uskmouth Power Company Ltd and SSE Renewables Ltd
Do you have any other comments?	

Workgroup Questions

Consultation Question 1: Do you agree with the recommendations of the Frequency Response Technical Subgroup? • Requirement for Faster Frequency Response on asynchronous plant? • Clearer Primary Response Requirements for synchronous plant?	Yes, as long as the value includes a comparison with the cost of providing the equivalent frequency response from synchronous plant. Yes
Consultation Question 2: Are there any impacts for generator owners that you would like to identify in relation to the recommendations? (e.g. costs, timescales, feasibility)	Needs to be a clear timeline for implementation of any change to avoid the need for a generator owner to alter the contracted technical specification with a turbine supplier for a new project. Consider not increasing the maximum infeed loss to 1800 MW rather than change the Rate of Change of Frequency settings for Power Park modules
Consultation Question 3: Are there any impacts for HVDC Converter owners that you would like to identify in relation to the recommendations? (e.g. costs, timescales, feasibility)	Unknown
Consultation Question 4: Are there any impacts for manufacturers that you would like to identify in relation to the recommendations? (e.g. costs, timescales, feasibility)	Yes, If the result of these recommendations introduces different requirements from the European Network Code, Requirements for Generators The RfG aims to harmonise technical requirements for manufacturers.

Consultation Question 5: Are there any additional comments you would like to make in relation to the frequency response technical requirements section of the consultation?	Cost of GB specific technical specifications, i.e. bespoke technical requirements for frequency response limits the warranty given by manufacturers and increases purchase and engineering support costs in GB
Consultation Question 6: Do you believe that Option A merits further investigation by the Workgroup? Please include your rationale.	Yes. Could be an efficient solution.
Consultation Question 7: Is there anything additional you wish to note regarding Option A?	There needs to be a high level of transparency with this option and it would need to be kept as simple as possible for ease of monitoring.
Consultation Question 8: Do you believe that Option B merits further investigation by the Workgroup? Please include your rationale.	No. Alternative technology is unproven and likely to be more expensive to implement
Consultation Question 9: Is there anything additional you wish to note regarding Option B?	No
Consultation Question 10: Do you believe that Option C merits further investigation by the Workgroup? Please include your rationale.	Yes. Option should be explored further in tandem with option A as there are potential benefits for a portfolio solution that could be more cost effective and efficient.
Consultation Question 11: Is there anything additional you wish to note regarding Option C?	The obligation to provide the required total service within portfolio or through a market could be an efficient solution. TSO and market should have visibility of portfolio arrangement. A combination of Options A & C would help create a market for single station generation to participate in.
Consultation Question 12: Do you believe that Option D merits further investigation by the Workgroup? Please include your rationale.	No This would prohibit the development of technologies to provide an enhanced frequency response service in a market.
Consultation Question 13: Is there anything additional you wish to note regarding Option D?	Why build a pump storage scheme and be penalised for the additional capability rather than rewarded for investment. Limits Market options. Very difficult to prescribe level required for new technologies.
Consultation Question 14: Do you believe that Option E merits further investigation by the Workgroup? Please include your rationale.	Yes, Would correctly incentivise capability and delivery of service. Encourages investment in frequency services.
Consultation Question 15: Is there anything additional you wish to note regarding Option E?	Could provide the basis of a CBA to evaluate investment required and potentially encourage investment in frequency services. Only works provided the incentives for additional capability are visible and secure over a contract term
Consultation Question 16: Do you believe that Option F merits further investigation by the Workgroup? Please include your rationale.	No Would be inefficient.

Consultation Question 17: Is there anything additional you wish to note regarding Option F?	No
Consultation Question 18: Do you believe that Option G merits further investigation by the Workgroup? Please include your rationale.	Yes. Would introduce a level of transparency that is not present currently and ultimately provide competition and lower overall costs.
Consultation Question 19: Is there anything additional you wish to note regarding Option G?	Preference would be for a D+2 auction to give more certainty and avoid conflict. Timing of auction within day would be critical.
Consultation Question 20: Do you believe that Option H merits further investigation by the Workgroup? Please include your rationale.	No. Not viable due to infrastructure
Consultation Question 21: Is there anything additional you wish to note regarding Option H?	No
Consultation Question 22: Are you aware of any element of the ENCs that would prevent the progression of the any of the technical requirements?	ENC, RfG still under development but progression to specific national requirements need to be CBA justified not imposed under Article 4(3).
Consultation Question 23: Are you aware of any element of the ENCs that would prevent the progression of the any of the commercial arrangements?	We note the development of the European Network Codes and would wish to see the implementation of the associated changes, in due course, be clearly flagged up in terms of the specific changes to the (GB) Frequency response arrangements at that time rather than being undertaken (in advance) via the consultation document as we may wish (at that future date) to no longer provide the service in the same way as we do currently if the terms and conditions and / or associated risks in providing Frequency Response materially change at that time.

1. Background

1.1 A major element of this study work is to establish the effect on System Frequency of the increasing volume of variable speed wind turbines and HVDC Converter technology. Whilst these issues are now well known, and set out in the 'Future Frequency Response Requirements' paper[1], it is worth briefly summarising the potential concerns.

1.2 Conventional synchronous generation which currently contributes to the majority of the Transmission System load is sensitive to changes in system frequency. In the event of the loss of a generating unit, the remaining synchronous plant will supply an injection of active power into the network through the stored energy in the rotating masses. This natural phenomena greatly assists in limiting the rate of change of system frequency.

1.3 Unfortunately, variable speed wind turbines and other static devices which utilise power electronic converters such as HVDC converters are insensitive to frequency changes and therefore do not behave in the same way as synchronous machines resulting in a diminution in the system frequency. This issue is illustrated in Figure 1 below.

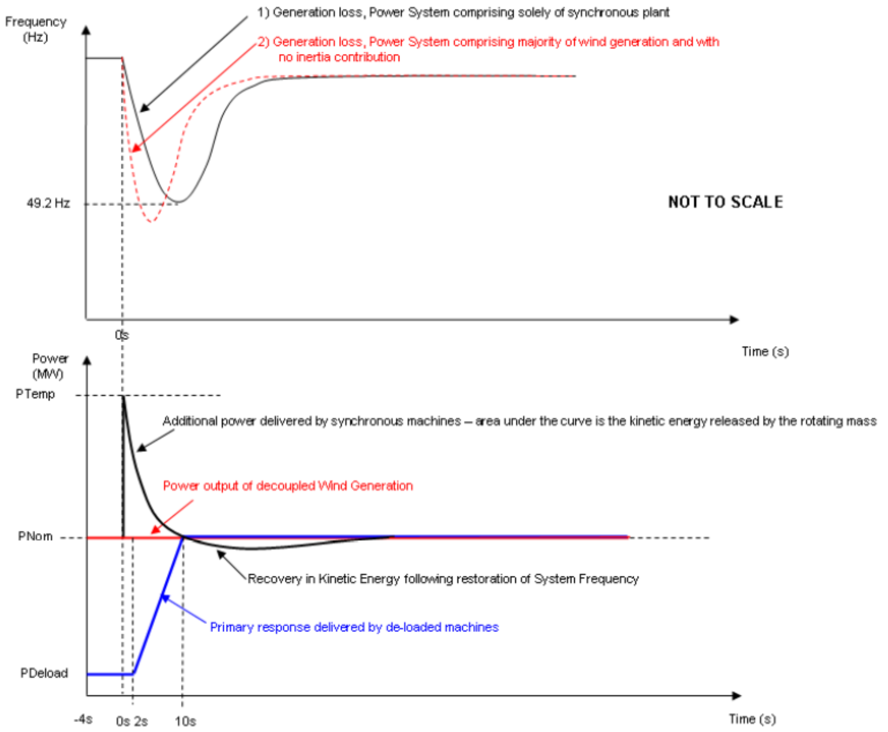

Figure 1: The effect of reduced system inertia on the management of a large infeed loss

1.4 As can be seen in the red curve of Figure 1, for the same generation loss, it is not possible to maintain the System Frequency above 49.2Hz when a high volume of asynchronous generation is connected to the system and unable to contribute to

[1] A copy of this paper can be found in Annex 3 of the Workgroup Consultation which is available at: http://www.nationalgrid.com/uk/Electricity/Codes/gridcode/consultationpapers/current/Frequency_Response/

system inertia. The reason for this is the lack of Active Power (shown by the red line) injected from the asynchronous generation as shown in the lower graph.

2. Initial Discussion

2.1 The Workgroup discussions focussed on two approaches to managing large frequency deviations on systems where a lack of 'natural' inertia meant that the system frequency may not be contained within satisfactorily limits.

2.2 The first approach considered was to investigate the option of equipping variable speed wind turbines and other asynchronous sources with a ‘synthetic inertia’ capability. This capability has the potential to improve frequency control without needing to curtail the power output of the wind turbine generating units prefault. This option was investigated at length and detailed discussions where held with a number of the major wind turbine manufacturers.

2.3 A number of manufacturers have indicated an ability to provide a synthetic inertia capability and have published papers and information on their capabilities - see references [1] – [4] in Annex 5. These controllers aim to inject power to the network in a similar way to that of a synchronous machine, but through controlled action.

2.4 As part of a control strategy, it is important to ensure sufficient active power is injected into the network to balance the loss of generation. Clearly too much active power injected into the network could result in temporary over frequencies occurring before governor action provides adequate downward regulation. For example, with a loss of generation of less than 300MW, only a small amount of active power would be required where as a larger injection would be required for the maximum loss of 1,800MW.

2.5 A good measure of the required level of active power injection can be obtained from a measure of the rate of change of system frequency (df/dt) (ie the smaller the value of df/dt the lower the initial injection of active power required).

2.6 National Grid modelled two controllers both using df/dt functionality. One was based on an initial injection and fixed decay based on the rate of change of system frequency. The second was based on a continuously acting df/dt controller which would operate throughout the entire disturbance, and in doing so regulating the active power injection to the network continuously. Based on the results, both controllers were able to inject sufficient active power to the network to ensure the maintenance of system frequency above SQSS limits. These are described in more detail in Annex 5.

2.7 Whilst system studies confirmed that both controllers could be used as a basis to resolve the issue of retaining frequency standards, further discussion identified two critical issues. These being:

- df/dt controllers are noise amplifying and can, even with appropriate filtering, fail to operate in the appropriate manner, particularly where small time constants are involved; and

- the recovery period for wind turbines operating at just below rated wind speed can result in substantial reductions in their active power output, resulting in a system frequency collapse some 10 to 15 seconds after the initial generation loss.

2.8 With regard to the df/dt issue, National Grid held extensive discussions with manufactures to examine the df/dt controller and how it could be improved. National Grid amended their own models and identified that even with slower response times the controller could still aid frequency containment.

2.9 It was also suggested that the controller should not only rely on a df/dt input but should also incorporate a frequency trigger. Consideration was also given to a simple 'one-shot' control which would deliver a fixed volume of energy with a defined ramp and decay period when frequency reached a pre-defined setting.

2.10 The simple 'one-shot' control would not have the control complexities of a df/dt trigger but would not adapt to a specific frequency event after the initial frequency disturbance, potentially resulting in an uncontrolled response.

2.11 With regard to recovery periods, concerns were raised relating to the potential reduction in power output from wind turbines following the provision of increased active power output in response to a frequency fall.

2.12 A variable speed wind turbine relies on operating at the optimum point on the Cp - λ curve in order to extract the maximum available power from the wind. This is a complex non linear function and becomes a significant issue when the wind turbine is operating just below rated wind speed. In the event that the wind turbines are operating at just below their rated wind speed and at the same time, activation of the synthetic inertia control is required, then once the additional active power has been injected into the network, the recovery period can result in a drop in power output of up to 30% of its pre fault output, resulting in a frequency collapse after the event.

2.13 Figure 2 below shows an illustrative frequency trace using a power injection equivalent to 10% of non-responsive wind generation, with a 10% loss of output from the same plant after 10 seconds.

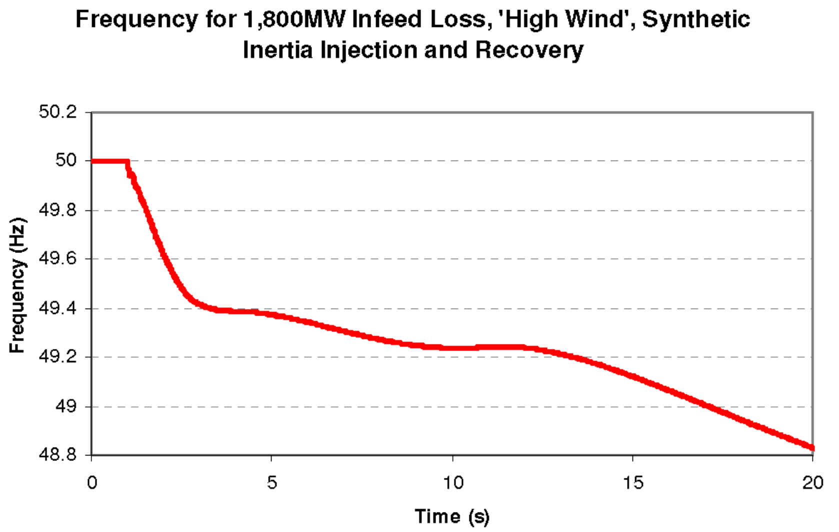

Figure 2: The effect of loss of active power output during the wind turbine 'recovery period'

2.14 In investigating this issue, a range of wind statistics was examined to determine the likelihood of a large volume of wind generation across the country operating at a similar wind speed. Data was also obtained to examine the effect of how wind speed varied within the wind farm.

2.15 The results of this analysis demonstrated that there was potentially a serious risk that a significant volume of geographically dispersed generation could be operating at a similar wind speed. The only guaranteed solution to this would be for the wind generation to be curtailed pre-fault, reducing the rate at which emission savings can be delivered.

2.16 An alternative approach to a synthetic inertia requirement would be to consider a method of rapidly injecting active power into the system following the loss of a generating unit by adopting a conventional proportional governor control.

2.17 This second approach was investigated using a response characteristic on frequency responsive wind generation that provided full primary Frequency Response within 5 seconds, being sustained for a further 25 seconds, rather than the current Grid Code requirement of delivery in 10 seconds and sustainable for a further 20 seconds.

2.18 The results of these studies demonstrated that the system frequency deviations could also be contained when 'Fast Frequency Response' was installed and that significant reductions in response requirements could also be achieved.

2.19 Discussions also highlighted concerns over the ability to deliver a synthetic inertia capability and conventional Primary Response from the same machines at the same time. It is therefore necessary to consider the likely generation patterns more carefully to check whether there is a sufficient amount of synthetic inertia capable plant which isn't already required to manage system frequency in Primary and Secondary response timescales.

2.20 In assessing the materiality of the issue, it is also important to consider the proportion of the time where a synthetic inertia requirement may be needed to allow National Grid to meet the frequency containment requirements of the SQSS. Initial simulations highlighted that achieving frequency containment was significantly more challenging at transmission system demands of 35GW and less. A review of transmission system demands for 2008 to 2010 suggests that this represents approximately 50% of the time.

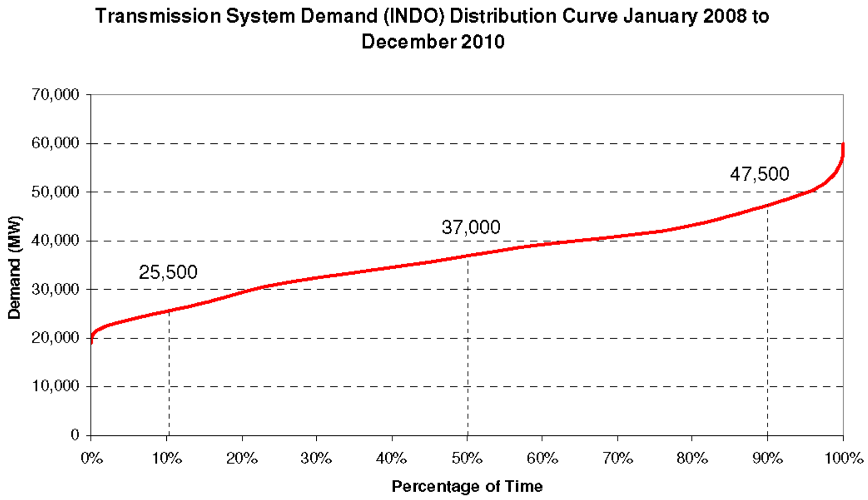

Figure 3: Transmission System Demand distribution curve

2.21 The next stage of analysis therefore needed to be based on clear demand and generation assumptions which are discussed in the next section.

3. Generation and Demand Scenarios

3.1 This section outlines how generation and demand scenarios were derived from which the final set of simulations could be based.

3.2 The starting point was to consider National Grid's Gone Green Scenario for the year 2020. Gone Green for 2020 embodies a generation capacity of 100GW, made up of 11GW nuclear, 27GW of wind, 50GW of fossil fuelled plant, 3GW of Pumped Storage, 6GW of Interconnectors, and 3GW of other renewables.

3.3 An individual generation pattern was developed for each demand level, and with a High, Average and Low wind resource. The wind resource levels incorporated in the scenarios were less at the lower demand levels than at the high, in line with observed wind load factors which are on average greater at high demand levels, and lesser at lower demand levels.

3.4 It is recognised that these wind resource assumptions do not capture the full range of possible wind conditions, but they do allow simulations to be constructed which illustrate how wind output assumptions impact on the generation mix and hence Frequency Response.

3.5 Each individual generation scenario was constructed by first examining the amount of generation which was likely to make the commercial decision to run at base load, a category made up mainly of nuclear and wind generation.

3.6 Next, a Primary Response requirement was estimated, including an assumed contribution to Primary Response from Low Frequency Relay triggered demand. The generator response volumes assumed in this exercise are given in Table 1 below.

3.7 The net response requirement was then apportioned to the available generation in the following order:

- Response was first allocated to fossil fuelled synchronous generation at a loading level of 85%, the loading point where, on average, the most effective ratio of response to deload is delivered. For demand scenarios above 35GW, this generation is generally already required to meet demand.

- Where the estimated response requirement could not be met on synchronous generation at 85% (ie generation exceeded demand), then plant was loaded at lower levels, giving more response per machine.

- If the response requirement could not be met using synchronous generation alone, response was allocated to asynchronous generation starting at 85%, with load reduced as necessary.

3.8 Additional balancing actions (such as synchronising additional generation) were also considered if necessary.

3.9 The generation scenarios constructed using this process were then used as a basis for individual simulations for each system demand level and wind resource assumption. The scenarios were then adjusted until the resulting simulated frequency trace was satisfactorily close to the target frequency of 49.2Hz when the system was subject to its largest loss.

3.10 All scenarios were derived as a single snapshot in time, and did not take into account any other system issues such as network constraints. Some of the approaches used to solve the Primary Response requirement problem may not be achievable in practice.

3.11 The spreadsheet used to represent the plant mix and generation background is shown in Annex 6.

3.12 Response volume assumptions were derived from information on recently commissioned generation. Ramp rate assumptions were then derived by calculating the rates necessary to achieve the required volumes. These are shown in Table 1 below.

Load Point (pu wrt Active Power)	Response Delivered (pu)	Response/ Deload	10 Second Ramp Rate (pu/s)	5 Second Ramp Rate (pu/s)
0.55	0.125	28%	0.0139	0.0313
0.65	0.125	36%	0.0139	0.0313
0.75	0.125	50%	0.0139	0.0313
0.85	0.082	55%	0.0091	0.0205
1.00	0	0%	0.0000	0.0000

Table 1: Frequency Response volume, delay and ramp rate assumptions

4. System Models to assess Frequency Response Requirements

4.1 In order to assess the future Frequency Response requirements, the following model shown in Figure 4 was constructed in Digsilent Power Factory.

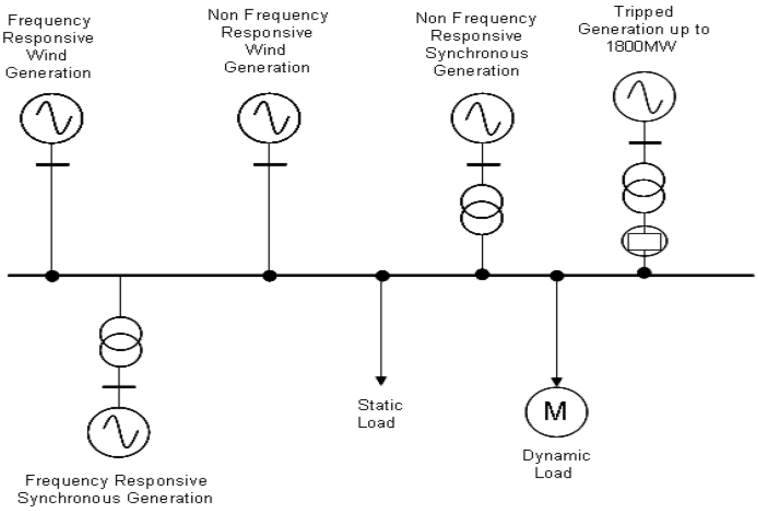

Figure 4: Model used to assess Frequency Response requirements

4.2 The model comprises of non frequency responsive synchronous and asynchronous generation together with frequency responsive synchronous and asynchronous generation.

4.3 The governor models used on the synchronous plant are generic but provide a representative reflection of aggregated plant behaviour. The models incorporate a droop characteristic, a ramp rate limit, amplitude limit and delay. The same parameters were used to represent both synchronous and asynchronous plant following a review of current plant capability.

4.4 The load was segregated into two components, namely a dynamic element (including a linear component and damping component) and a static element. These are important as some load relief will be realised as the frequency changes. The maximum generation loss was initially set at 1,800MW to reflect the increased loss in the SQSS but could be varied.

4.5 This single busbar, lumped machine model was considered adequate for the simulations required to investigate system wide synthetic inertia and Primary Response requirements. Local and distributed effects could not be investigated using this model and should be examined more carefully in future work.

5. Evaluating Primary Response Requirements

5.1 As described above, simulations were conducted for each demand and generation pattern and adjusted until the resulting simulated frequency trace was satisfactorily close to the target frequency of 49.2Hz when the system was subject to its largest loss. Figure 5 below illustrates how the time of the frequency minimum reduces as demand and hence inertia reduces.

Changing Rate of Simulated Frequency Fall for 1,800MW Infeed Loss - Low Wind

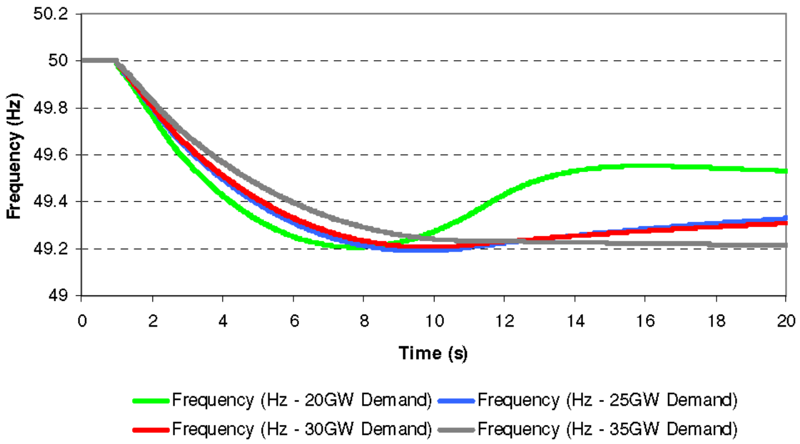

Figure 5: Changing rate of frequency fall with reducing demand

5.2 Where the frequency minimum point falls before 10 seconds after the infeed loss event (which occurs at one second in these simulations) care needs to be taken when deriving the Primary Response required to achieve containment. Rather than simply looking at the response delivered, it is necessary to back-calculate the response scheduled by referencing the machine loading point against the response that would have been delivered at the 10 second point.

5.3 Figure 6 below shows the response delivered by synchronous generators in the 20, 25 and 35GW simulations for Low Wind conditions. In these examples, the responsive generators (in the case of the 25 and 35 GW simulations) are loaded at 85% of their active power capability, and 75% (in the case of the 20 GW simulation).

5.4 The scheduled response is therefore equivalent to the value given in Table 1 multiplied by the active power rating of the machine. In the case of the 25GW and 35GW simulations, this is 8.2% of the loading point divided by 0.85. In the 20GW simulation, the loading point is reduced to 75% to get the additional response required, therefore the response scheduled is 12.5% of rating, which is equivalent to the machine loading divided by 0.75.

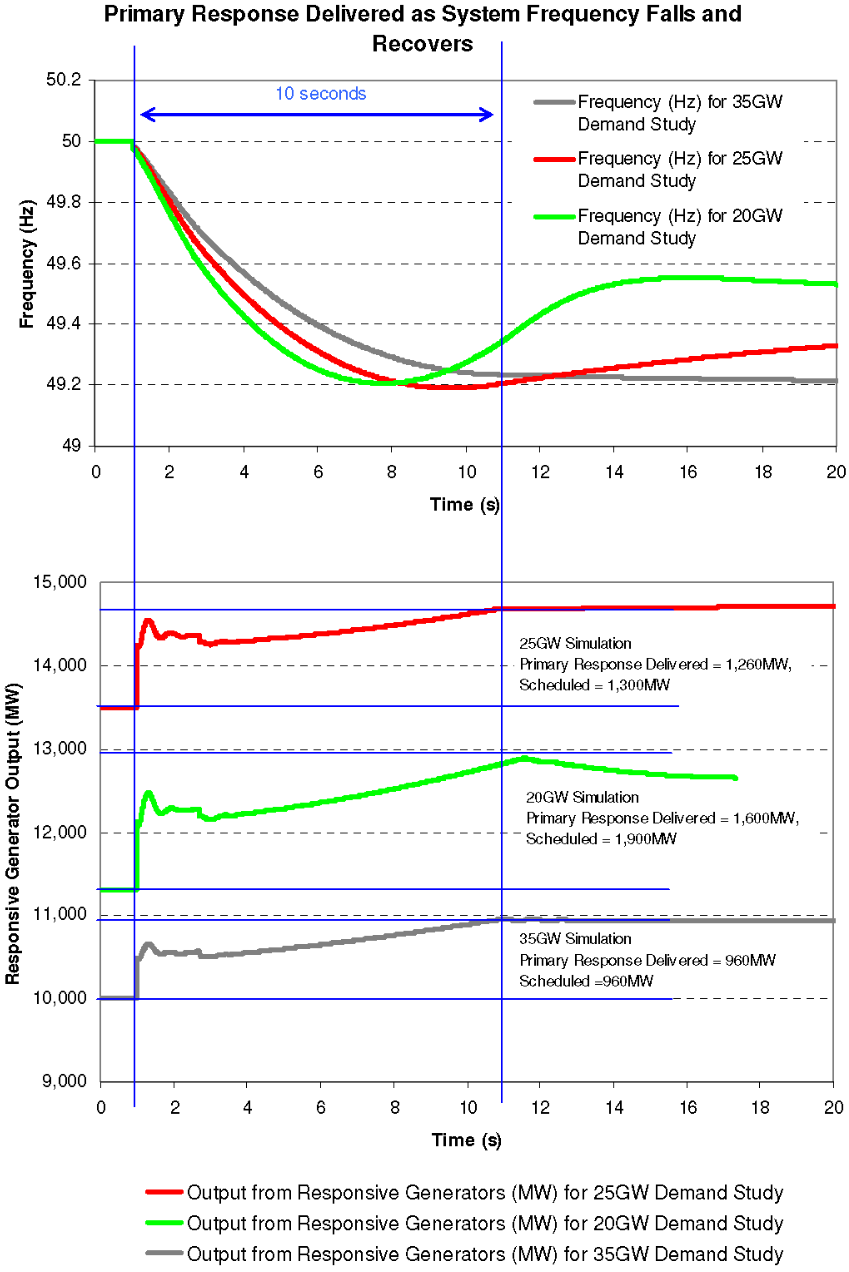

Figure 6: Primary Response Delivery Profile

5.5 As the rate of frequency fall increases, the discrepancy between the amount of response scheduled and the response that is delivered at the time required increases. This means that as the rate of frequency fall increases such that it interacts with responsive generators ramping, the requirement for primary Frequency Response increases in line with the assumed ramp rate as well as with the change in system characteristics.

6. Sensitivity to Primary Response Assumptions

6.1 Simulations were carried out using a governor characteristic where the expected volume of Primary Response was delivered over 10 seconds, with a delay of 1 second before Frequency Response was initiated. A linear ramp over the next 9 seconds was assumed. Figure 7 below shows how changing the delay assumption to 3 seconds (with ramping over 6 seconds) results in the non-compliant frequency trace shown in red.

6.2 In this example, additional response of 500MW had to be scheduled in order to achieve compliance with a 3 second delay.

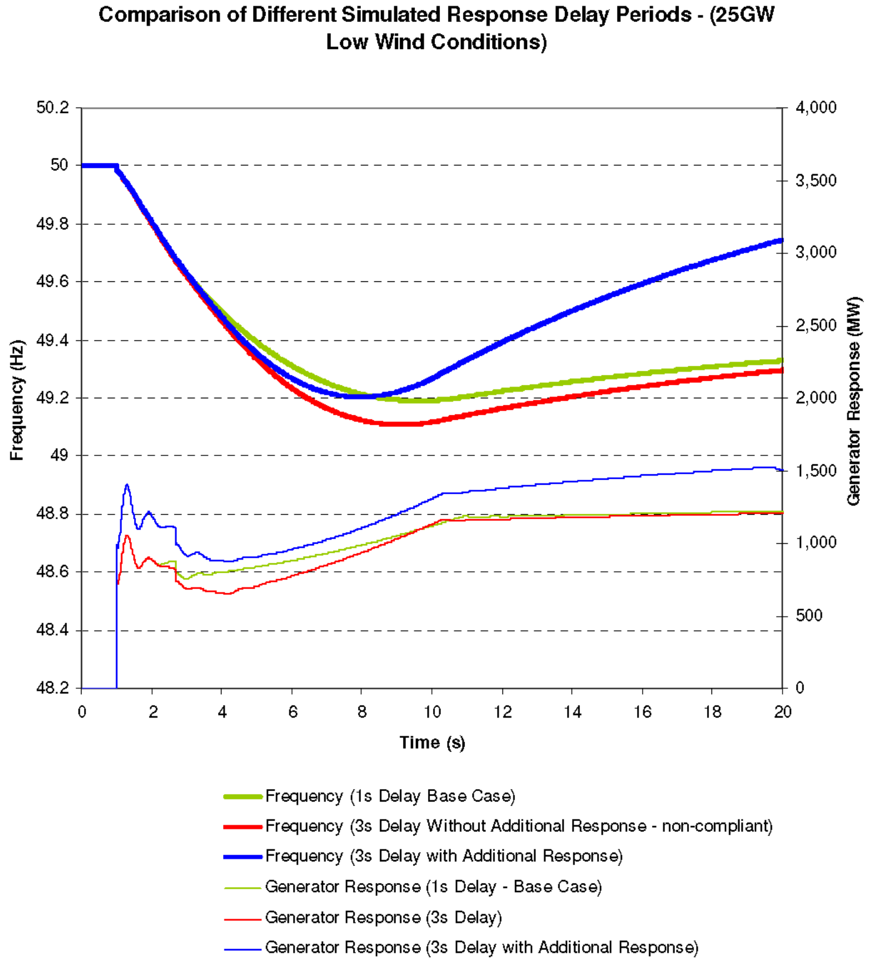

Figure 7: Comparison of Response Delay Periods

7. Frequency Response Erosion

7.1 The historic approach to setting Primary Response requirements is to check compliance for a frequency deviation to 49.2Hz, with a starting frequency of 50Hz. In practice, it is necessary to take account of uncertainties in the simulation and also to consider the effects of starting at frequencies lower than 50Hz. A margin is then added to the requirements to reflect this. This effect becomes more important as larger volumes of dynamic response are scheduled.

7.2 Figure 8 below shows the impact of a large infeed loss when the initial frequency is low. An imbalance was introduced to the simulation to set the initial frequency at approximately 49.9Hz before the large infeed loss

7.3 occurred. In this case, an additional 200MW had to be scheduled (on top of the ~1,000MW required in the base case simulation) to ensure that the region in which there is a risk of Low Frequency Demand Disconnection of operating was not encroached upon.

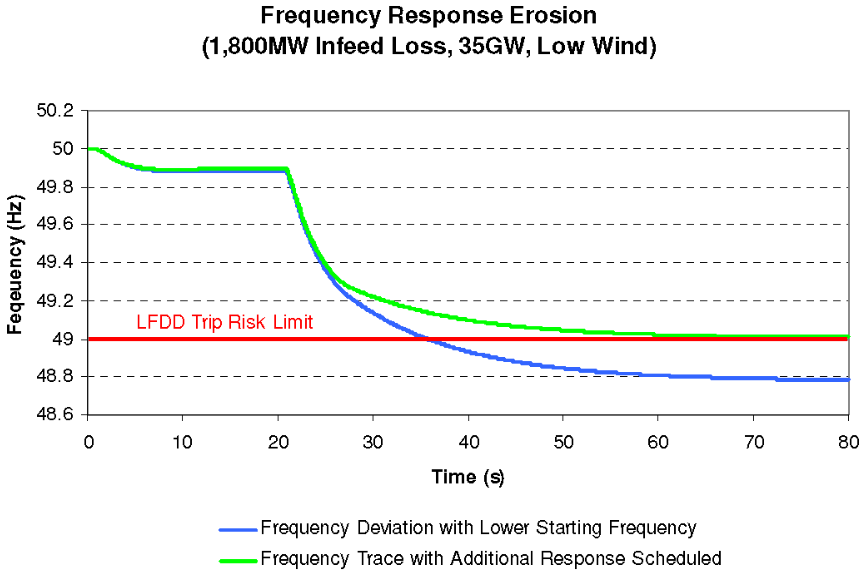

Figure 8: Frequency Response Erosion

7.4 Therefore, in order to cater for the erosion risk, a factor of 20% has been applied to the requirements presented in this report where these are met by 'dynamic' response sources (ie not 'static' frequency triggered demand control). Further work is required to derive a margin which is robust in all relevant cases.

8. Response Requirements

8.1 This section sets out the Primary Response volume requirements that have been derived by simulation for an 1,800MW infeed loss and for a 1,320MW infeed loss. Requirements are given for the demand and generation backgrounds described in the ‘demand and generation’ section above and detailed in Annex 6 up to a transmission system demand of 55GW. At demands higher than 55GW, the simulated rate of frequency fall was such that containment was required in secondary response timescales only.

1,800MW Infeed Loss - *Low Wind*

8.2 Figure 9 below shows the simulated Primary Response requirements for an 1,800MW Infeed Loss under Low Wind conditions. At low system demands the Primary Response requirement is seen to increase noticeably. This is caused by the frequency fall coinciding with frequency responsive generation ramping.

8.3 Low frequency triggered response of 200MW was incorporated in all simulations with the balance of Primary Response coming from synchronous generation and delivered in 10 seconds. It should be noted that the effect of low frequency triggered response was very effective at arresting the fall in system frequency.

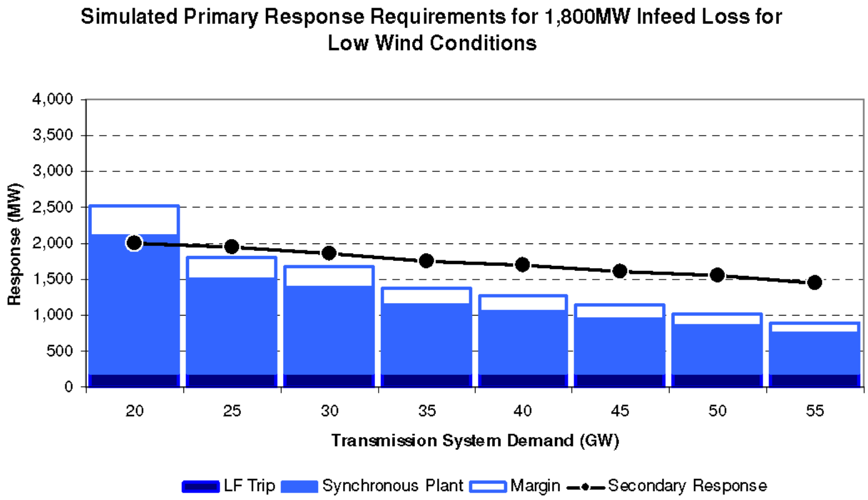

Figure 9: Primary Response Requirements, 1,800MW Loss, Low Wind

8.4 The secondary response requirement is also shown. In general terms, where the Primary response requirement is higher, this means that additional balancing actions need to be taken purely to meet the Primary Response requirement.

1,800MW Infeed Loss - Average Wind

8.5 Figure 10 below shows the simulated Primary Response requirements for an 1,800MW Infeed Loss under Average Wind conditions. Again, the increased requirement can be seen at lower system demands.

8.6 Low frequency triggered response of 200MW was incorporated in all simulations with the balance of Primary Response coming from synchronous generation and delivered in 10 seconds, apart from the 20GW simulation. In this case, asynchronous generation was used to make up the balance of the response requirement.

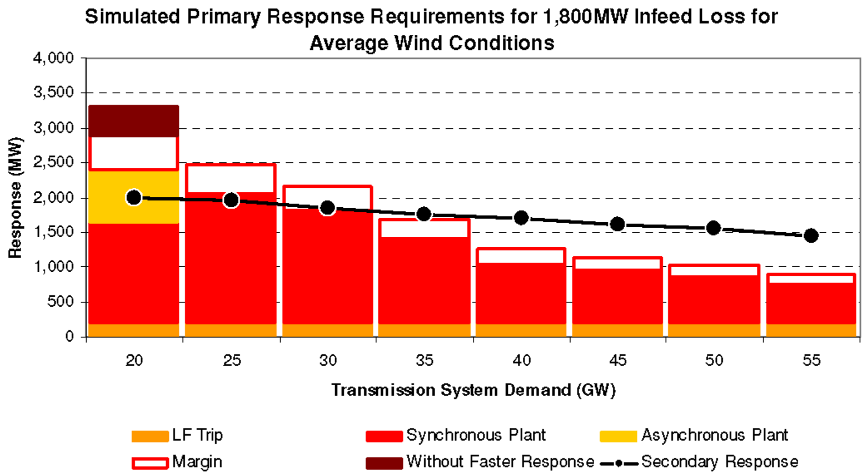

Figure 10: Primary Response Requirements, 1,800MW Loss, Average Wind

8.7 Two approaches were applied, one with asynchronous response delivered in 5 seconds (ie fast response) and one in 10 seconds. The difference between the two was equivalent to approximately 400MW of Primary Response.

1,800MW Infeed Loss - *High Wind*

8.8 Figure 11 shows the simulated Primary Response requirements for an 1,800MW Infeed Loss under High Wind conditions. Again, the larger requirement can be seen at lower system demands. Low frequency triggered response of 200MW was again incorporated in all simulations apart from the 20GW simulation where 350MW was utilised. The balance of Primary Response came from synchronous generation, delivered in 10 seconds, for simulations at 40GW and above. In the other cases, asynchronous generation was used to make up the balance of the response required.

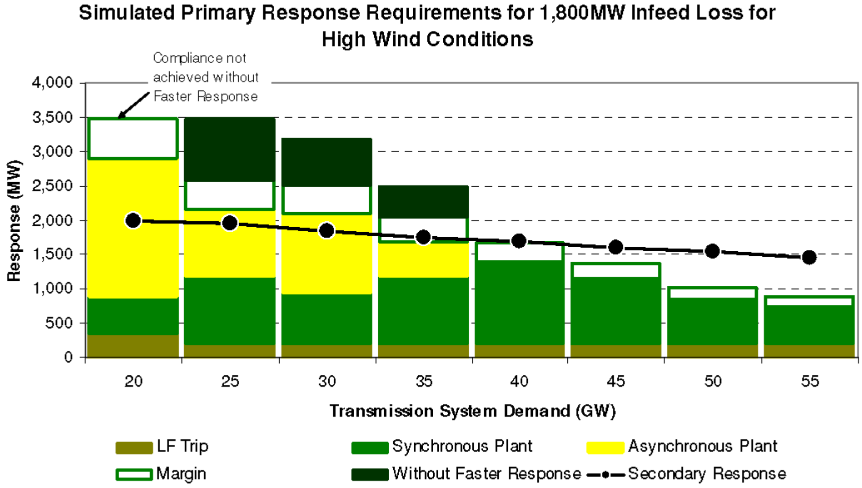

Figure 11: Primary Response Requirements, 1,800MW Loss, High Wind

8.9 Again, two approaches were applied, one with asynchronous response delivered in 5 seconds and one in 10 seconds. The difference between the two was equivalent to between 450MW and 900MW of Primary Response.

8.10 Frequency containment could not be achieved for the 20GW simulation in the absence of Fast Frequency Response. The frequency trace is shown in Figure 12.

8.11 The 20GW simulation also yielded the highest Rate of Change of Frequency at -0.68Hz/s. Further work is required to assess whether this has any impact on the deployment of Rate of Change of Frequency based protection for the purposes of loss of mains protection.

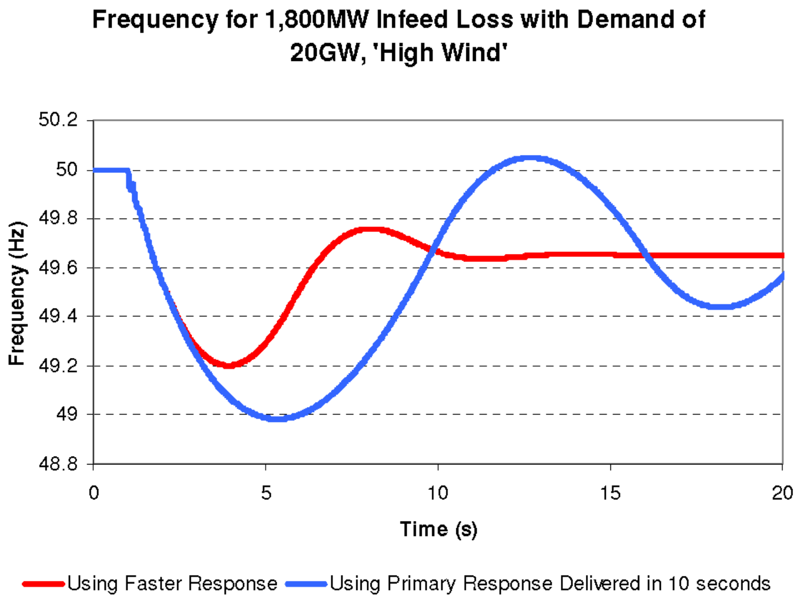

Figure 12: Frequency for 1,800MW Loss at 20GW, High Wind

1,320MW Infeed Loss - *Low Wind*

8.12 A similar process was followed to examine the primary Frequency Response requirement for a 1320MW infeed loss. In this case the SQSS stipulates that frequency should be contained to 49.5Hz rather than 49.2Hz.

8.13 The simulated Primary Response requirements for a 1,320MW Infeed Loss under Low Wind conditions are shown in Figure 13.

8.14 Low frequency triggered response of 200MW was incorporated in all simulations with the balance of Primary Response coming from synchronous generation and delivered in 10 seconds.

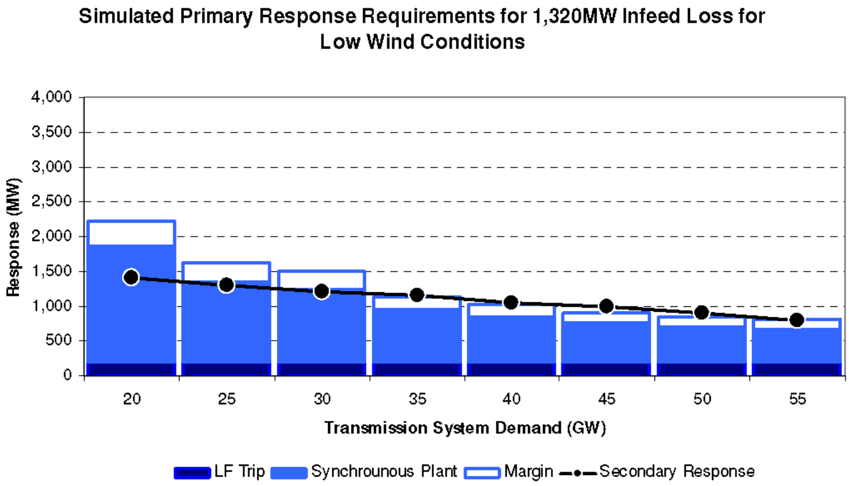

Figure 13: Primary Response Requirements, 1,320MW Loss, Low Wind

1,320MW Infeed Loss - *Average Wind*

8.15 Figure 14 shows the simulated Primary Response requirements for a 1,320MW Infeed Loss under Average Wind conditions.

8.16 Low frequency triggered response of 200MW was incorporated in all simulations with the balance of Primary Response coming from synchronous generation and delivered in 10 seconds, apart from the 20GW simulation. In this case, asynchronous generation was used to make up the rest of the response requirement.

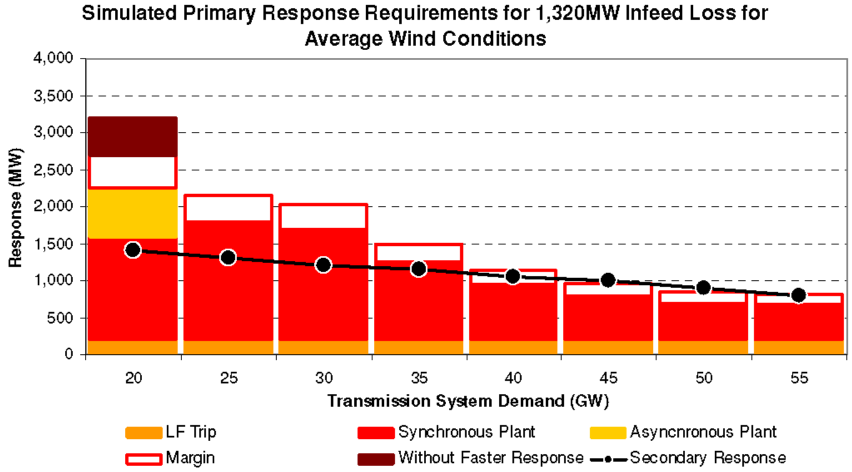

Figure 14: Primary Response Requirements, 1,320MW Loss, Average Wind

8.17 As in the case of the 1,800MW infeed loss, two approaches were applied, one with asynchronous response delivered in 5 seconds (ie fast response) and one in 10 seconds. The difference between the two was equivalent to approximately 500MW of Primary Response.

1,320MW Infeed Loss - *High Wind*

8.18 The simulated Primary Response requirements for a 1,320MW Infeed Loss under High Wind conditions are illustrated in Figure 15.

8.19 Low frequency triggered response of 200MW was incorporated in all simulations apart from the 20GW simulation where 350MW was utilised. Primary Response synchronous generation, delivered in 10 seconds, was sufficient to contain the frequency deviation for simulations at 40GW and above. In the other cases, asynchronous generation was used to make up the rest of the response requirement.

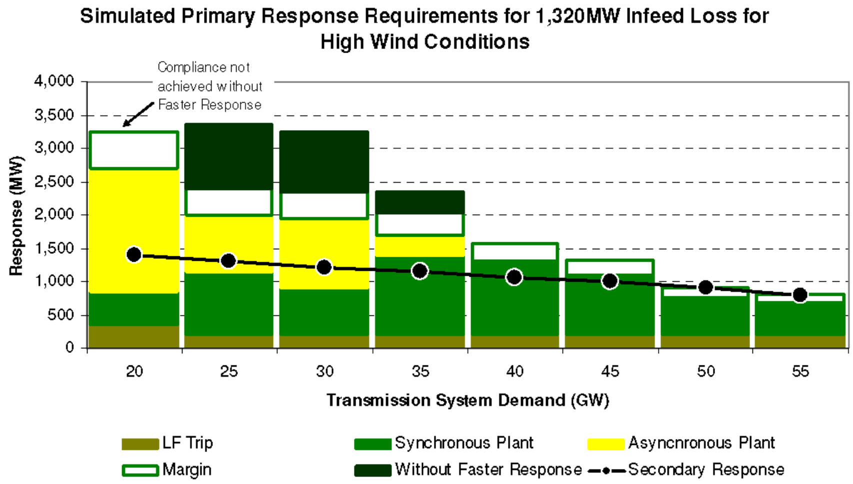

Figure 15: Primary Response Requirements, 1,320MW Loss, Low Wind

8.20 Again, two approaches were applied, one with asynchronous response delivered in 5 seconds and one in 10 seconds. The difference between the two was equivalent to between 300MW and 950MW of Primary Response. Containment could not be achieved in the 20GW simulation without fast response.

Summary of Low Frequency Response Requirements

8.21 Table 2 and Figure 16 provide an overall summary of the response requirement derived by simulation for Low, Average and High Wind conditions.

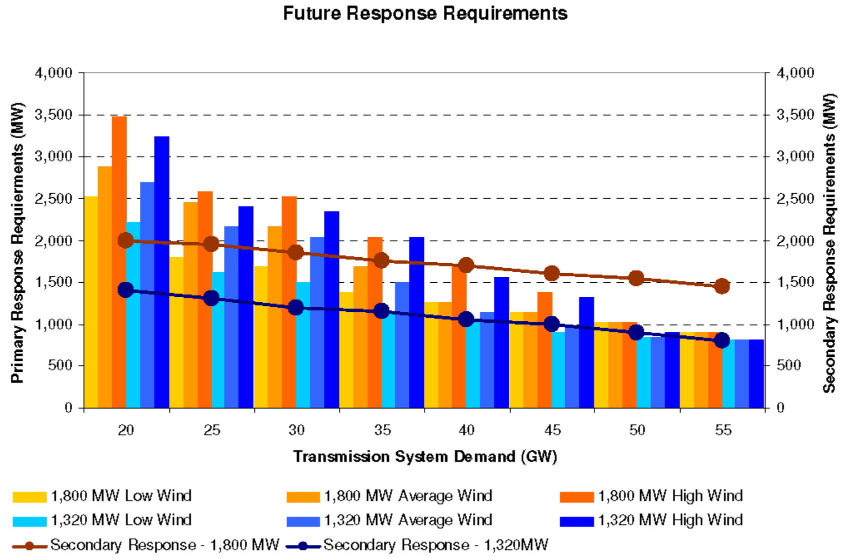

Figure 16: Future Low Frequency Response Requirements

		System Demand (GW)							
		20	25	30	35	40	45	50	55
Primary Response Requirement									
Low Wind	1,800 MW	2,520	1,800	1,680	1,380	1,260	1,140	1,020	900
	1,320 MW	2,220	1,620	1,500	1,140	1,020	900	840	810
Average Wind	1,800 MW	2,880	2,460	2,160	1,680	1,260	1,140	1,020	900
	1,320 MW	2,700	2,160	2,040	1,500	1,140	960	840	810
High Wind	1,800 MW	3,480	2,580	2,520	2,040	1,680	1,380	1,020	900
	1,320 MW	3,240	2,400	2,340	2,040	1,560	1,320	900	810
Secondary Response Requirement									
	1,800 MW	2000	1950	1850	1750	1700	1600	1550	1450
	1,320 MW	1400	1300	1200	1150	1050	1000	900	800

Table 2: Future Low Frequency Response Requirements

9. High Frequency Response Requirements

9.1 A range of simulations were carried out to examine High Frequency response requirements. Volumes have not been calculated for the purposes of this report. However, many of the issues highlighted for Primary Response above are the same for High Frequency response.

9.2 Figure 17 shows a simulated frequency trace for a 1,400MW demand loss which shows that the maximum frequency point occurs at less than 10 seconds. This highlights that the issues of ramp rate, delay and response volume discussed above in relation to Primary Response are equally valid for High Frequency response.

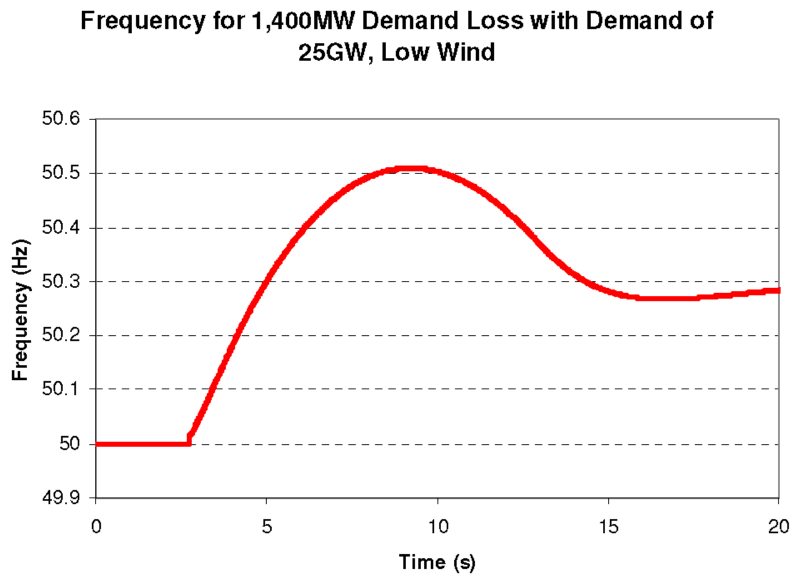

Figure 17: Frequency for 1,400MW Demand Loss

10. Impact of Varying Primary Response Timescales

10.1 The Primary Reponse requirements outlined above enable comparison to be made between requirements derived where response from asynchronous plant is delivered within 5 seconds and the requirements where all primary response from generation is delivered in 10 seconds.

10.2 The 5 second delivery time was initially selected based on the time that system frequency reached its minimum in simulations for the 20GW demand scenario. Further simulations were performed to investigate the benefit delivered as Primary Response timescales are reduced from 10 seconds.

10.3 Figures 18 and 19 show how the Primary Response requirement reduces as delivery timescales on asynchronous plant are reduced, using a 25GW and 35GW 'High Wind' generation and demand pattern.

10.4 The Primary Response requirement is shown at varying response delivery timescales alongside the reduction in requirement compared to the current 10 second criteria.

10.5 The incremental reduction (the reduction in requirement achieved by speeding response up by one second) is shown in the line plot on the secondary axis. In the cases investigated here, the incremental improvement reaches its peak value where response is delivered in 4 or 5 seconds.

10.6 Response rates of less than 5 seconds deliver less incremental benefit under these simulated conditions and would be expected to be more challenging to implement. Note that the 20% margin applied to the requirements in the sections above has not been applied in this analysis.

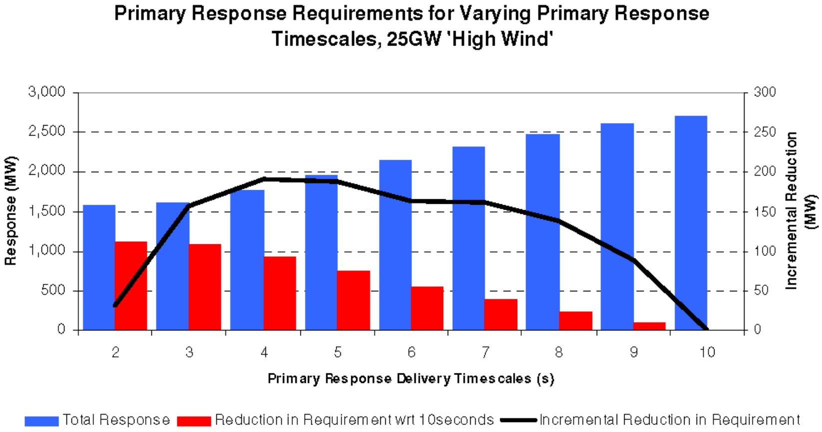

Figure 18: Varying Primary Response Timescales at 25GW system demand

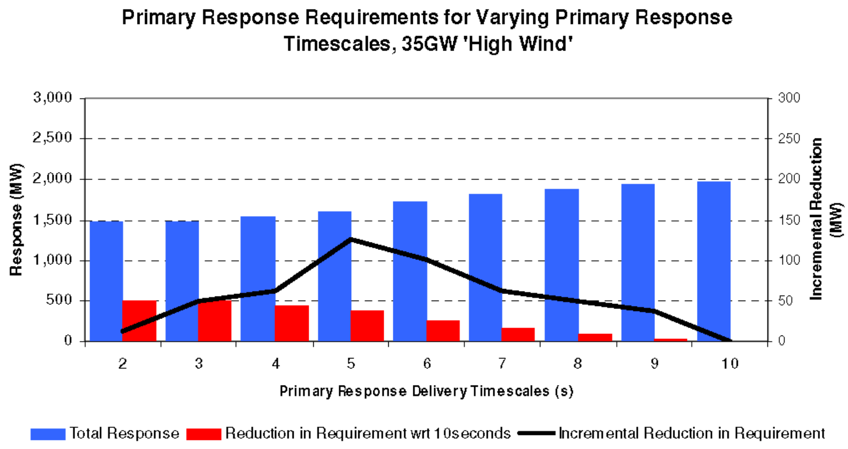

Figure 19: Varying Primary Response Timescales at 35GW system demand

11. Manufacturer Feedback

11.1 Wind turbine manufacturers played an active role in Technical Subgroup discussions, providing a great deal of useful guidance to the group. A number of points were raised within discussions including:

- the need for clarity and uniformity in requirements;
- timescales to develop equipment to meet new requirements; and
- the need to consider local and distributed system issues when specifying control system requirements.

11.2 The Technical Subgroup also discussed the synthetic inertia requirement developed in Canada which was understood to be similar to the 'one-shot' option discussed (with a power delivery profile thought to be suited to the Canadian system). Frequency response requirements in Ireland were also debated. These were understood to focus on faster delivery of Primary response, similar to the 5 second criteria already being discussed in the Technical Subgroup.

11.3 It should however be noted that some areas of equipment capability could not be discussed fully within the Technical Subgroup. National Grid therefore sought confidential feedback on a range of questions relating to Synthetic Inertia and Fast Frequency Response. Replies were received from 5 wind turbine manufacturers and one HVDC manufacturer.

11.4 All of the replies from wind turbine manufacturers stated that Fast Frequency Response (in 5 seconds) could be delivered by wind turbines with the exception of one, who stated it was not possible to confirm this at this time.

11.5 A number of replies highlighted that the delivery of Frequency Response by wind turbines was dependant on the wind resource available.

11.6 No specific implementation costs were provided but a number of the replies stated that development costs for them were likely to be associated with software and control systems rather than in turbine hardware.

11.7 Some replies indicated an implementation time, with the minimum quoted at 18 months, maximum at 2 years.

11.8 A number of replies also highlighted a desire to continue development work on a synthetic inertia. One also highlighted the potential benefits of synthetic inertia where its provision could mean that curtailment of wind would be minimised.

11.9 None of the respondents felt able to make specific comment on the provision of synthetic inertia or fast primary response on offshore networks connected via HVDC. However, one reply stated that the desired response timescales were well within the capabilities of current HVDC technology, providing an energy source was available.

12. Conclusions

12.1 In order to manage the Transmission System in the future and ensure system frequency can be managed to the criteria set out in the SQSS, there will be a requirement to mitigate the reduced contribution to system inertia from decoupled generation plants such as variable speed wind turbines and other static plant such as HVDC Converters.

12.2 The following conclusions were drawn from National Grid's simulations based on a 'Gone Green' generation scenario for the year 2020:

- A supplementary frequency control facility can deliver significant benefits in managing the 1,800MW and 1,320MW infeed risk at system demand levels of 35GW and below under all but "Low Wind" conditions.
- The measures needed to ensure compliance with the SQSS, and avoid impacting on system security, become more severe and more significant in volume as system demand, and the capacity of any synchronous generation meeting it, decreases;
- Additional low frequency relay triggered demand response was required as well as supplementary frequency control capability to achieve frequency containment at system demands of 20GW under 'High Wind' conditions;
- These factors suggests that both a supplementary frequency control capability and alternative actions will be required to ensure frequency containment can be achieved at demands of less than 25GW. Further alternative actions include:
    - Curtailment of the largest infeed loss; and
    - Additional balancing actions, such as:
        - curtailment of interconnectors or inflexible plant;
        - displacement using plant with additional response capability;
        - fast acting low frequency relay triggered response; and
        - addition of inertia, by 'low load operation' on synchronous generation for example.

12.3 It should be noted that the simulations were based on an interconnector position of 'float' (ie no import/export) and that any net interconnector import has the effect of displacing synchronous plant. There is currently 3.5 GW of interconnector capacity on the transmission system, a variability of 7GW. It should however be noted that the volume of interconnectors to Great Britain may increase in the future.

12.4 A number of supplementary frequency control capability options were investigated, including a pure 'df/dt' driven fast acting control on un-curtailed asynchronous plant which is intended to mimic the inertia capability of a synchronous machine. This form of control provides an ideal solution, as it helps solve the frequency control problem without the need to curtail wind. However, there are a number of issues associated with it:

- Any control system will incorporate a processing delay which needs to be limited to ensure the desired effect is achieved;

- Rate of Change of Frequency as an input parameter is inherently noise amplifying leading to unpredictability of response;

- Care needs to be taken not to extract too much energy from wind turbines as this can lead to an extended and detrimental recovery period, particularly at specific points on the wind turbine operating curve. This leads to some uncertainty over the volume and timescales of energy available; and

- Discussions suggest that wind based Power Park Modules will find it difficult to deliver both a 'df/dt' driven fast acting control and Primary Response consecutively with the volumes required. This issue is critical as work to date suggests that both are required under most of the relevant system scenarios.

12.5 Alternative synthetic inertia controllers based on Rate of Change of Frequency, using fixed and variable volumes were investigated. It was demonstrated that these options provided a potential solution to the frequency containment problem, provided that the correct volumes and characteristics could be specified. These would need to be validated for the full range of possible future system conditions.

12.6 Finally, the option of using faster acting proportional frequency control was investigated by taking a conventional Primary Response characteristic and adapting it to deliver response within 5 seconds rather than 10. This characteristic was applied to wind generation which was already curtailed in order to provide conventional Primary Response within the simulations described in this report.

12.7 This capability had the effect of reducing the Primary Response requirement and hence the need to curtail renewable generation significantly. A benefit of between 400MW and 950MW was observed in the simulations presented in this report. If one assumes that this benefit applies for 10% of the year at an average of 500MW and response price of

12.8 30 £/MW/h, a benefit of £13m per year in balancing cost could be attributed to this capability. There would be an additional carbon benefit for the wind curtailment avoided.

12.9 Based on the analysis conducted, it has been concluded that the single change to response provision that would yield the most significant benefit is through the introduction of a fast primary Frequency Response capability applicable to all decoupled generation sources which do not naturally provide an inertial contribution.

12.10 Such generating plant should have the capability to provide 10% or more of its registered capacity as primary Frequency Response which should be delivered linearly over a 5 second period from the inception of the generation loss or load change and an initial delay of no more than 1 second from the inception of the frequency change.

12.11 It is recognised that this specification may present a challenge to technology providers and manufacturers. However, it is believed that this specification is more achievable, at an earlier implementation date, than the df/dt triggered control option discussed above.

12.12 Simulations also showed a high degree of sensitivity to the ramp rate assumptions for Primary Response. It is recommended that these are specified explicitly within the Grid Code by setting out a maximum response delay of 1 second and specifying that response should be delivered linearly up to 10 seconds or 5 seconds as appropriate.

12.13 Whilst it is acknowledged that these proposals could resolve the issue for Plant in excess of 50MW, some consideration will still be required as to how this issue will be addressed in respect of Small Embedded Power Stations as this segment of the market is expected to grow in the future.

12.14 The studies have also demonstrated the effect on rate of change of system frequency against a credible set of future generating scenarios. As a conclusion it is seen that this will impact on Embedded Generation, in particular the effect on protection settings. It is therefore suggested that this report is highlighted to the Distribution Code Review Panel for further consideration in respect of Embedded Generation.

12.15 A final point to note is the extent of reliance on wind generation to deliver frequency control in the analysis performed in this report. Operators have little experience of this to date and it may be necessary to revisit the technical and commercial arrangements for the provisions of Frequency Response for asynchronous generators as more experience is gained.

12.16 Annex 7 contains text which sets out the very high level principles in addressing the need for a fast frequency response in order to address the issue of a diminishing contribution to system inertia from generating plants which are insensitive to changes in system frequency. The text has been drafted in the style of Grid Code change for illustrative purposes only.

13. Recommendations

Faster Frequency Response

13.1 Faster Frequency Response capability delivered within 5 seconds, for low and high frequencies, on users bound by the provisions of the Grid Code allows Frequency Response volumes to be reduced significantly in the situations analysed in this report.

(a) The value of faster Frequency Response should be assessed, taking into consideration the costs of implementation and the benefits in reduced curtailment of generation from renewable sources and other balancing costs; and

(b) Subject to this assessment, proposals should be developed for the appropriate obligations and/or market arrangements to ensure sufficient Frequency Response capability is available to maintain system security for anticipated future generation and demand patterns.

Clearer Primary Response Requirements

13.2 The simulations conducted by the Technical Subgroup have demonstrated the sensitivity of Frequency Response requirements to the ramping capability of responsive generation. The Grid Code requirements for Frequency Response should be reviewed with the aim of clarifying the ramping capability required from responsive generation in terms of:

(a) Adequacy of information provided on performance; and

(b) The need to stipulate minimum delay times and ramping capability for new providers.

Rate of Change of Frequency

13.3 The simulations performed by the Technical Subgroup give some indication to the potential change in the maximum Rate of Change of Frequency settings which needs to be considered in the context of the loss of mains protection deployed on embedded generation.

1.0 Synthetic Inertia Models

1.1 Two controllers were considered and tested. These being a one shot df/dt controller and a continuously acting df/dt controller. Both designs relied on Rate of Change of Frequency as a trigger signal. The reason being that Rate of Change of Frequency is a good measure as to the volume of generation lost. Clearly for the controller to work effectively it needs to know that the frequency has fallen and equally the rate of change of system frequency. For example, it would not appropriate to require the controllers to inject a fixed volume of active power irrespective of the generation loss as small generation losses could potentially result in temporary over frequencies and large generation losses could result in a risk of breaching the lower frequency limit. Both of these are controllers are described in detail below.

2.0 The One Shot df/dt Controller

2.1 The one shot df/dt controller is designed to inject an initial increase in active power following a frequency change in proportion to the Rate of Change of Frequency. The full active power injection should be available within 200ms and then decay exponentially over a period of Ts seconds. A small power recovery period of up to 5% of nominal power is permitted but limited to prevent the risk of subsequent frequency deviations following the initial generation loss or load change. An illustration of the control strategy is shown in Figure A1.0.

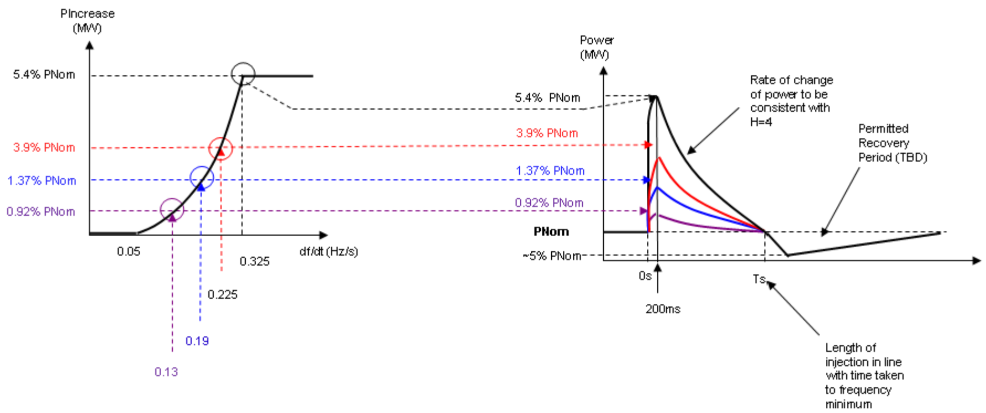

Figure A1.0

2.2 This control scheme was found to work well however, as the decay was exponential, ie generated by a mathematical function there was always a risk that the intended response would not be guaranteed if a subsequent event were to occur in the period between 0 – Ts seconds. For the purposes of the studies, a figure of 10 seconds was used although this was changed as a sensitivity. In addition, following discussions with manufacturers, the rise time of 200ms was debated as an issue as it would be difficult to implement using a df/dt controller. In respect of this, a number of sensitivity studies were run with different rise times to establish the effect on overall system frequency.

3.0 The Continuously Controlled df/dt Controller

3.1 The continuously controlled df/dt controller was developed to inject Active Power into the system in proportion to the rate of change of system frequency. In this event, the maximum active power would be injected then the rate change of system frequency is at its greatest. A representation of this controller is shown in Figure A2.0.

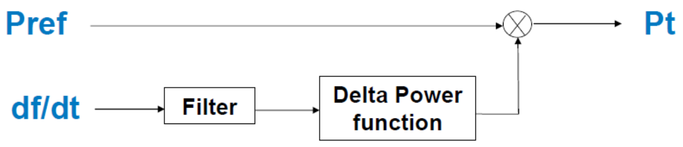

Figure A2.0

3.2 As with the one shot controller, this control system was also identified to work well ensuring that system frequency could be retained within statutory limits. Again, in response to questions raised at the working group, the delay time at which full active power was achieved from the inception of the frequency fall was examined and no major issues were identified with a 1 second delay time as shown in Figure A3.0.

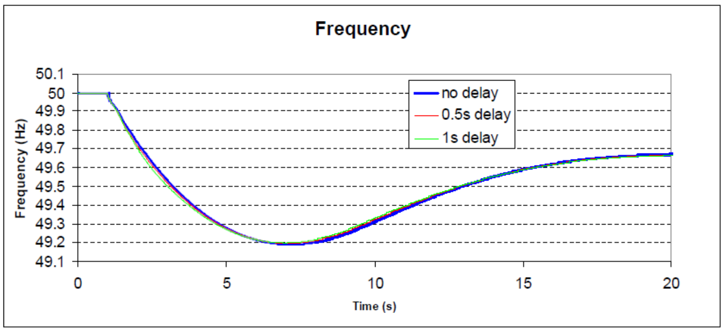

Figure A3.0

4.0 Rate of Change of Frequency as a Controlled Parameter

4.1 Both the one shot controller and continuously controlled df/dt controller utilised df/dt as an input parameter to provide the required response from the Wind Turbine. Whilst this is a good measure of how much generation has been lost or how much load has changed, unfortunately df/dt (being predictive) is a noise amplifying process which requires appropriate filtering, but equally can be triggered by non genuine generation losses such as switching incidents etc. In addition, as the control action would rely on the initial Rate of Change of Frequency, it would need to be quite fast acting and therefore the design of appropriate filtering becomes even more challenging.

4.2 In addition to the problems of df/dt as a control function, the problem of the recovery period as explained in references [1], [2] and [3] of this Appendix caused serious concerns to the adoption of a synthetic inertia controller. Since the issue could be resolved by the action of fast acting response, it was suggested that this would provide a better solution.

5.0 References

[1] Grid Code Review Panel Paper Reference pp10/21, Future Frequency Response requirements, dated September 2010.

[2] Contribution of Wind Energy Converters with Inertia Emulation to frequency control and frequency stability in Power Systems – Stephan Wachtel and Alfred Beekmann – Enercon – Presented at the 8th International Workshop on Large Scale Integration of Wind Power into Power Systems as well as on Offshore Wind Farms, Bremen Germany, 14 – 15 October 2009.

[3] Variable Speed Wind Turbines Capability for Temporary Over-Production – German Claudio Tarnowski, Philip Carne Kjaer, Poul E Sorensen and Jacob Ostergaard

[4] Study on Variable Speed Wind Turbine Capability for Frequency Response - German Claudio Tarnowski, Philip Carne Kjaer, Poul E Sorensen and Jacob Ostergaard

Annex 6 - Generation Scenarios

GG Year:2020

	Generation Capacities	Summer 20GW High Wind	Summer 20GW Average Wind	Summer 20GW Low Wind	Summer 25GW High Wind	Summer 25GW Average Wind	Summer 25GW Low Wind	Spring/Autumn 30GW High Wind	Spring/Autumn 30GW Average Wind	Spring/Autumn 30GW Low Wind	Spring/Autumn 35GW High Wind	Spring/Autumn 35GW Average Wind	Spring/Autumn 35GW Low Wind
Demand		20	20	20	25	25	25	30	30	30	35	35	35
Additional Demand (ie Pumping)		2	2	2	2	2	2						
Total Demand		22	22	22	27	27	27	30	30	30	35	35	35
Generation													
"Must Run" generation													
Baseload Synchronous	11.8	6.7	6.7	6.7	6.7	6.7	6.7	7.6	7.6	7.6	8.2	8.2	8.2
Wind	26.8	16.1	8.0	.0	16.1	8.0	.0	20.1	9.4	1.3	20.1	9.4	1.3
Total "Must Run"	38.6	22.8	14.8	6.7	22.8	14.8	6.7	27.7	17.0	8.9	28.2	17.5	9.5
Total Generation Capacity	100.0												
Primary Response													
Requirement		2.9	2.4	2.0	2.2	1.8	1.5	2.1	1.8	1.4	1.8	1.4	1.2
Static Response		0.4	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Net Response Req		2.6	2.2	1.8	2.0	1.6	1.3	1.9	1.6	1.2	1.6	1.2	1.0
Response on Synchronous Plant		0.5	1.5	1.8	1.0	1.6	1.3	0.8	1.6	1.2	1.1	1.2	1.0
Response on Asynchronous Plant		2.0	0.8	0.0	1.0	0.0	0.0	1.2	0.0	0.0	0.5	0.0	0.0
Response on Synchronous Plant													
Assumed Loading Point		75%	75%	75%	75%	75%	85%	75%	75%	85%	75%	85%	85%
Assumed Deload/Response Ratio		50%	50%	50%	50%	50%	55%	50%	50%	55%	50%	55%	55%
Responsive Plant Deload		1.1	2.9	3.6	2.0	3.2	2.4	1.5	3.2	2.2	2.2	2.2	1.7
Power Output on Responsive Plant		3.2	8.7	10.8	6.0	9.6	13.5	4.5	9.6	12.4	6.6	12.4	9.8
Response on Asynchronous Plant													
Assumed Loading Point		75%	75%	85%	85%	85%	85%	75%	85%	85%	85%	85%	85%
Assumed Deload/Response Ratio		50%	50%	55%	55%	55%	55%	50%	55%	55%	55%	55%	55%
Responsive Plant Deload		4.0	1.5	0.0	1.7	0.0	0.0	2.3	0.0	0.0	0.9	0.0	0.0
Power Output on Responsive Plant		12.1	4.5	0.0	9.8	0.0	0.0	6.9	0.0	0.0	5.2	0.0	0.0
Additional Balancing (Pullback)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Output on Non-responsive Plant		0.0	2.0	0.0	4.5	8.0	0.0	10.9	9.4	1.3	14.0	9.4	1.3
Aggregate Response													
Power Output on Responsive Plant		15.3	13.2	10.8	15.8	9.6	13.5	11.4	9.6	12.4	11.8	12.4	9.8
Responsive Plant Deload		5.1	4.4	3.6	3.7	3.2	2.4	3.8	3.2	2.2	3.1	2.2	1.7
Additional Output Reqd		0.0	0.0	4.5	-0.1	2.6	6.8	0.1	3.4	8.6	1.1	5.0	15.7
Additional Balancing (Pullback)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Generation		22.0	22.0	22.0	27.1	27.0	27.0	30.0	30.0	30.0	35.0	35.0	35.0

	Spring/Autumn 40GW High Wind	Spring/Autumn 40GW Average Wind	Spring/Autumn 40GW Low Wind	Winter 45GW High Wind	Winter 45GW Average Wind	Winter 45GW Low Wind	Winter 50GW High Wind	Winter 50GW Average Wind	Winter 50GW Low Wind	Winter 55GW High Wind	Winter 55GW Average Wind	Winter 55GW Low Wind
Demand	40	40	40	45	45	45	50	50	50	55	55	55
Additional Demand (ie Pumping)												
Total Demand	40	40	40	45	45	45	50	50	50	55	55	55
Generation												
"Must Run" generation												
Baseload Synchronous	8.7	8.7	8.7	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1
Wind	20.1	9.4	1.3	24.1	10.7	1.3	24.1	10.7	1.3	24.1	10.7	1.3
Total "Must Run"	28.8	18.1	10.1	34.2	20.8	11.5	34.2	20.8	11.5	34.2	20.8	11.5
Total Generation Capacity												
Primary Response												
Requirement	1.4	1.1	1.1	1.1	1.0	1.0	0.9	0.9	0.9	0.8	0.8	0.8
Static Response	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Net Response Req	1.2	0.9	0.9	0.9	0.8	0.8	0.7	0.7	0.7	0.6	0.6	0.6
Response on Synchronous Plant	1.2	0.9	0.9	0.9	0.8	0.8	0.7	0.7	0.7	0.6	0.6	0.6
Response on Asynchronous Plant	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Response on Synchronous Plant												
Assumed Loading Point	75%	85%	85%	75%	85%	85%	85%	85%	85%	85%	85%	85%
Assumed Deload/Response Ratio	50%	55%	55%	50%	55%	55%	55%	55%	55%	55%	55%	55%
Responsive Plant Deload	2.4	1.6	1.6	1.7	1.4	1.4	1.2	1.2	1.2	1.0	1.0	1.0
Power Output on Responsive Plant	7.2	8.8	8.8	5.1	7.8	7.8	6.7	6.7	6.7	5.7	5.7	5.7
Response on Asynchronous Plant												
Assumed Loading Point	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Assumed Deload/Response Ratio	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%
Responsive Plant Deload	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Output on Responsive Plant	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Additional Balancing (Pullback)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Output on Non-responsive Plant	20.1	9.4	1.3	24.1	10.7	1.3	24.1	10.7	1.3	24.1	10.7	1.3
Aggregate Response												
Power Output on Responsive Plant	7.2	8.8	8.8	5.1	7.8	7.8	6.7	6.7	6.7	5.7	5.7	5.7
Responsive Plant Deload	2.4	1.6	1.6	1.7	1.4	1.4	1.2	1.2	1.2	1.0	1.0	1.0
Additional Output Reqd	4.0	13.1	21.1	5.7	16.4	25.8	9.1	22.4	31.8	15.1	28.5	37.8
Additional Balancing (Pullback)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Generation	40.0	40.0	40.0	45.0	45.0	45.0	50.0	50.0	50.0	55.0	55.0	55.0

	Low Demand 20GW High Wind	Low Demand 20GW Average Wind	Low Demand 20GW Low Wind	Low Demand 25GW High Wind	Low Demand 25GW Average Wind	Low Demand 25GW Low Wind	Median Demand 30GW High Wind	Median Demand 30GW Average Wind	Median Demand 30GW Low Wind	Median Demand 35GW High Wind	Median Demand 35GW Average Wind	Median Demand 35GW Low Wind
Nuclear	60%	60%	60%	60%	60%	60%	65%	65%	65%	70%	70%	70%
Wind	60%	30%	0%	60%	30%	0%	75%	35%	5%	75%	35%	5%
CCS	0%	0%	0%	0%	0%	0%	50%	50%	50%	50%	50%	50%
Other	75%	75%	75%	75%	75%	75%	80%	80%	80%	80%	80%	80%

	Median Demand 40GW High Wind	Median Demand 40GW Average Wind	Median Demand 40GW Low Wind	High Demand 45GW High Wind	High Demand 45GW Average Wind	High Demand 45GW Low Wind	High Demand 50GW High Wind	High Demand 50GW Average Wind	High Demand 50GW Low Wind	High Demand 55GW High Wind	High Demand 55GW Average Wind	High Demand 55GW Low Wind
Nuclear	75%	75%	75%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Wind	75%	35%	5%	90%	40%	5%	90%	40%	5%	90%	40%	5%
CCS	50%	50%	50%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Other	80%	80%	80%	90%	90%	90%	90%	90%	90%	90%	90%	90%

1.0 General

1.1 The proposals below set out the very high level principles in addressing the need for a Fast Frequency Response in order to address the issue of a diminishing contribution to system inertia from generating plants which are insensitive to changes in system frequency.

1.2 For illustrative purposes only, the proposals have been drafted in the style of a Grid Code change. It is envisaged that the major changes would relate to the Glossary and Definitions, CC.6.3.7 and CC.A.3.

2.0 High Level Proposals for Primary Response

2.1 In order to limit the Rate of Change of Frequency following a generation loss or load change, each Generating Unit, Power Park Module (including Power Park Units thereof) or DC Converters which are insensitive to changes in system frequency and do not inherently contribute to system inertia shall be required to provide a Fast Primary Frequency Capability in addition to the requirements of CC.6.3.7 and CC.A.3.

2.2 A Fast Primary Frequency Capability shall be defined as:-

> "Primary Frequency Capability where the increase in Active Power output or as the case may be, the decrease in Active Power Demand must be in accordance with the provisions of the relevant Ancillary Services Agreement which will provide that it will be released increasingly with time over the period 0 – 5 seconds from the time of the start of the frequency fall (allowing for a maximum 1 second delay) on the basis set out in the Ancillary Services Agreement and fully available by the latter and sustainable for at least a further 25 seconds. The interpretation of Fast Primary Frequency Response to a -0.5Hz frequency change is shown diagrammatically in Figure CC.A.3.4.

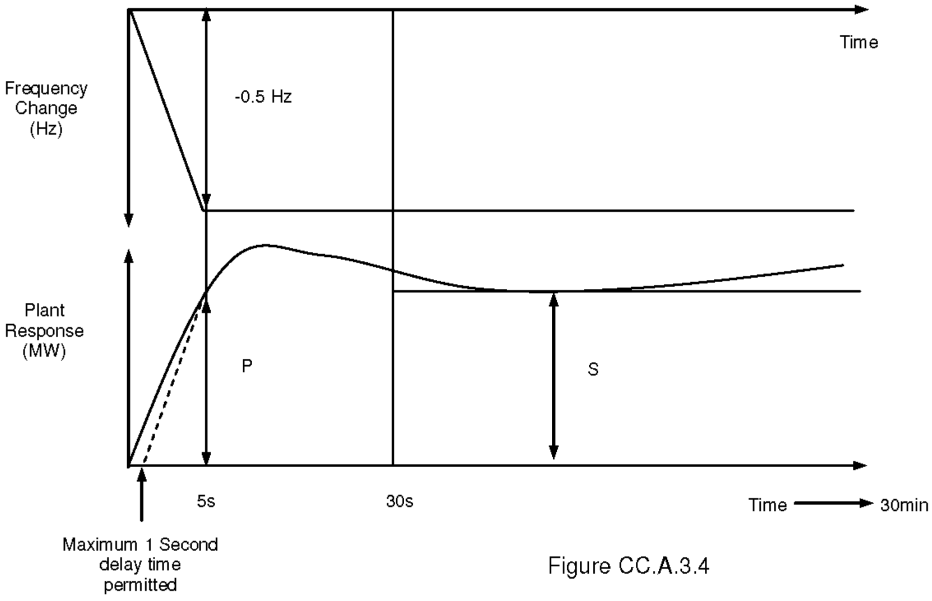

Figure CC.A.3.4

3.0 High Level Proposals for High Frequency Response

3.1 In order to limit the Rate of Change of Frequency following a demand loss or load change, each Generating Unit, Power Park Module (including Power Park Units thereof) or DC Converters which are insensitive to changes in system frequency and do not inherently contribute to system inertia shall be required to provide a Fast High Frequency Response Capability in addition to the requirements of CC.6.3.7 and CC.A.3.

3.2 A Fast High Frequency Response Capability shall be defined as:

> "High Frequency Response where the reduction in Active Power output in response to an increase in System Frequency above the Target Frequency (or such other level Frequency as may have been agreed in an Ancillary Services Agreement). This reduction in Active Power output must be in accordance with the provisions of the relevant Ancillary Services Agreement which will provide that it will be released increasingly with time over the period 0 – 5 seconds from the time of the start of the frequency increase (allowing for a maximum 1 second delay) on the basis set out in the Ancillary Services Agreement and fully achieved within 5 seconds of the time of the start of the Frequency increase and it must be sustained at no lesser reduction thereafter. The interpretation of Fast High Frequency Response to a +0.5Hz frequency change is shown diagrammatically in Figure CC.A.3.5".