National Grid Electricity Transmission System Operator (SO) Incentives for 1 April 2010

Initial Proposals Consultation

Version 1.0

Issued 5th November 2009

Responses requested by 16 December 2009

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Executive Summary

National Grid Electricity Transmission (NGET) is the National Electricity Transmission System Operator (NETSO) for England, Scotland, Wales and Offshore, defined hereon in as National Grid for simplicity.

Under the Transmission Licence, National Grid is obliged to perform Balancing Services Activities (BSA), which are defined as the operation of the transmission system and the procurement and use of Balancing Services required for reliable operation of the transmission system.

National Grid is obligated under the terms of the Transmission Licence to balance the system in a safe, efficient, economic and co-ordinated manner. The application of financial incentives encourages National Grid to invest in systems and resources to ensure BSA costs and risks are economically and efficiently managed and that innovative ideas and procedures are developed to reduce costs in return for a share of any savings delivered.

The Balancing Services Incentive Scheme (BSIS) is designed to deliver financial benefits to the industry and consumers from reductions in the costs or minimising risk associated with operating the electricity transmission network. The current format of the BSIS has been in place since NETA implementation in 2001.

In 2007 Ofgem trialled a new consultation process for SO incentives by asking National Grid Electricity Transmission (NGET) to lead on the development of Initial Proposals. Having reviewed the success of this approach, Ofgem has again asked NGET to lead on the engagement with industry and development of Initial Proposals for SO Incentives to be implemented from 1st April 2010.

This document provides an initial view of National Grid's forecast for the costs of system operation from April 2010 along with the drivers and assumptions made in reaching this forecast. In addition it also presents some options for the design of incentive schemes covering 2010/11 and 2011/12. The aim of the document is to present and seek views from the industry on the assumptions made in producing this forecast and the design of suitable incentive schemes based on this forecast.

Responses to this consultation will be used by Ofgem to inform the development of their Final Proposals for SO incentives for implementation from April 2010. These should be available in early 2010. Any responses received will be placed on our website (unless explicitly requested not to) and sent in full to Ofgem.

Executive Summary

The key themes in this proposal are summarised below:

- National Grid's preferred scheme for implementation on 1st April 2010 is a:
    - single year unbundled constraints incentive scheme
    - two year scheme for the remaining bundled cost components with current NIA methodology and reactive power default price adjustment

  We present our reasoning for this in section 4

- We forecast incentivised costs, excluding constraints, to total £485.4m for 2010/11 and £524.8m for 2011/12

- We propose creating a term to index the price of reactive power in line with the CUSC formulation for default reactive prices. This would reduce the central forecast of incentivised costs to £439.2m for 2010/11 and £473.5m for 2011/12.

- We set out the drivers and assumptions made in reaching these forecasts and seek comments of these.

- We forecast constraint costs to total £477m for 2010/11. Due to the lack of certainty of transmission and generation outages and other driving factors beyond 2011, it is very challenging to forecast constraint costs for 2011/12 with any reasonable degree of certainty. We explore how these issues can be addressed to realise longer term constraints incentives.

- With the above values, BSUoS is forecast to total £1262.2m for 2010/11. As we have not forecast constraint costs for 2011/12, a BSUoS value can not be given for this year.

- Finally, we examine the impact on IS systems of the proposed scheme designs and seek views from industry participants as to the impact on their systems.

- Summary Table

	2010 – 2011	**2011 – 2012**
IBC (Excl. Constraints)	**£485.4m**	**£524.8m**
IBC (Excl. Constraints) + Reactive Incentive Adjustment	**£439.2m**	**£473.5m**
Constraints	**£477m**	**Not Available**
BSUoS	**£1262.2m**	**Not Available**

Responses to this consultation should be sent to
soincentives@uk.ngrid.com

by 5pm on 16 December 2009

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Section 1
Overview

This section of the report introduces National Grid and the principles behind the Balancing Services Incentive Scheme (BSIS). An overview of 2009/10 BSIS progress is detailed along with information about the consultation process that has been recently carried out in preparation for the 2010/11 initial proposals.

1.1 An Introduction to National Grid

1 National Grid Electricity Transmission (NGET) is the National Electricity Transmission System Operator (NETSO) for England, Scotland and Wales, defined hereon in as National Grid for simplicity.

2 Under the Transmission Licence, National Grid is obliged to perform Balancing Services Activities (BSA), which are defined as the operation of the transmission system and the procurement and use of Balancing Services required for reliable operation of the transmission system.

3 National Grid is obligated under the terms of the Transmission Licence to balance the system in a safe, efficient, economic and co-ordinated manner. The application of financial incentives encourages National Grid to invest in systems and resources to ensure BSA costs and risks are economically and efficiently managed and that innovative ideas and procedures are developed to reduce costs in return for a share of any savings delivered.

1.2 The Balancing Services Incentive Scheme (BSIS)

4 The BSIS is designed to deliver financial benefits to the industry and consumers from reductions in the costs or minimising risk associated with operating the electricity transmission network. The current BSIS incentive format has been in place since NETA implementation in 2001.

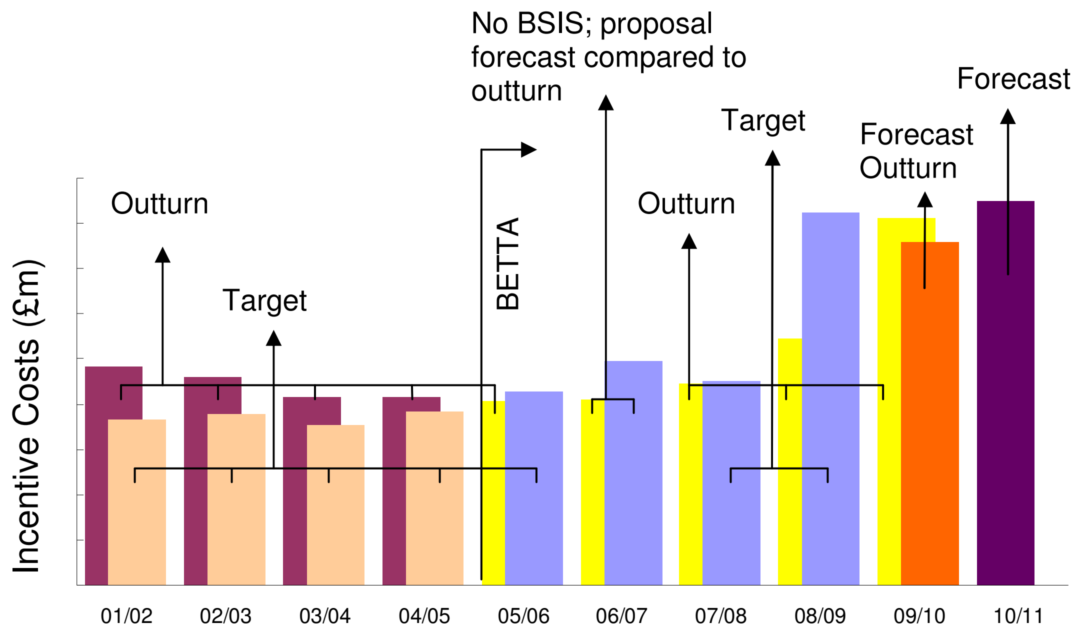

Figure 1: Incentive Scheme Performance

5 Figure 1 shows the BSIS outturn costs versus the agreed target since NETA go-live. As can be seen, the incentive cost outturn was below the target for the first four years of NETA. Since the introduction of BETTA, the outturn costs have been above the agreed target mainly due to increases in constraint and margin costs above those forecast. The outturn costs for 2009/10 incentive year are currently forecast to be below the target costs, an explanation of the reasons for this are detailed later in this section.

6 The BSIS provides a focus on key areas where National Grid is able to create value for the industry and consumers by reducing operating costs, and improving the accuracy and provision of information for use by the industry to better facilitate the market. The BSIS allows National Grid to retain a share of any value created or to bear a share of the costs should targets not be met.

7 The agreed timetable for the development of the BSIS commencing in April 2010 is as follows;

Date	Action
June / July 2009	Initial Industry Consultation/Engagement
July/ August 2009	Publication of mini consultation documents
November 2009	Publication of Initial Proposals
10th November 2009	BSIS Initial Proposals Workshop
November 2009	Ofgem to provide initial comments
December 2009	Initial Proposals consultation period closes
February 2010	Ofgem consultation on Final Proposals
1st April 2010	Scheme 'Go-Live'

8 This document introduces National Grid's initial proposals for the scheme due to commence from 1st April 2010, as described above. The agreed format for these initial proposals is for National Grid to present the cost drivers and assumptions used in the forecast and thus build up the explanation of the forecasting model and the drivers associated with each scheme option. A forecast of the costs for energy related components for 2011/12 is also included.

9 Feedback from the industry is essential for the development of these proposals from initial view into the final proposals. All responses to these initial proposals will be published on NGET's website (unless a specific request is made not to) and all responses will be sent in full to Ofgem.

10 **Responses to these initial proposals should be sent to:**

soincentives@uk.ngrid.com

by 16th December 2009

1.3 BSIS and BSUoS

11 National Grid is permitted to derive revenue for the Balancing Services Activities (BSA) carried out under the terms of the Transmission Licence. These costs are recovered via the Balancing Services Use of System (BSUoS) charges.

12 All participants who are subject to the Connection and Use of System Code (CUSC) [1] are obliged to pay BSUoS charges based on the amount of energy each participant has taken from or supplied to the National Grid in each half hour settlement period.

13 Costs incentivised through BSIS form a proportion of the BSUoS charges paid by CUSC signatories, as described above. BSIS costs can be categorised into two main groups; external costs and internal costs;

- The internal BSIS costs include National Grid's internal costs for operating the transmission system. For example, staff and IS overheads.

- The external BSIS costs recover the external costs National Grid incurs when operating the transmission system. These costs include BM (BM) charges, contracts and trading carried out to minimise the costs of actions shown in Figure 2 below.

[1] http://www.nationalgrid.com/uk/Electricity/Codes/

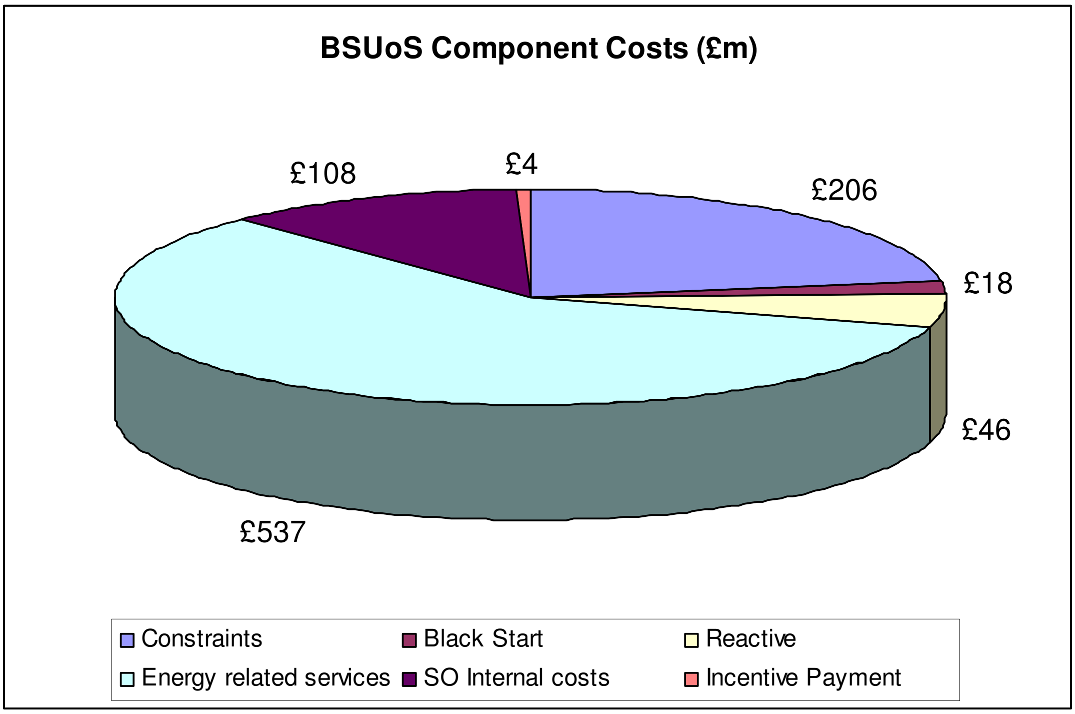

Figure 2: 2009/10 BSUoS cost forecast (September 2009)

14 The BSIS incentivises National Grid to be innovative and increase efficiency and cost effectiveness in carrying out its BSAs, thus reducing overall Incentivised Balancing Costs (IBC).

15 Currently the BSIS target is agreed and implemented as a one year scheme. Therefore each year, a revised target is developed and agreed. The targets for the System Operator (SO) internal incentive are agreed in line with the Transmission Price Control Review (TPCR).

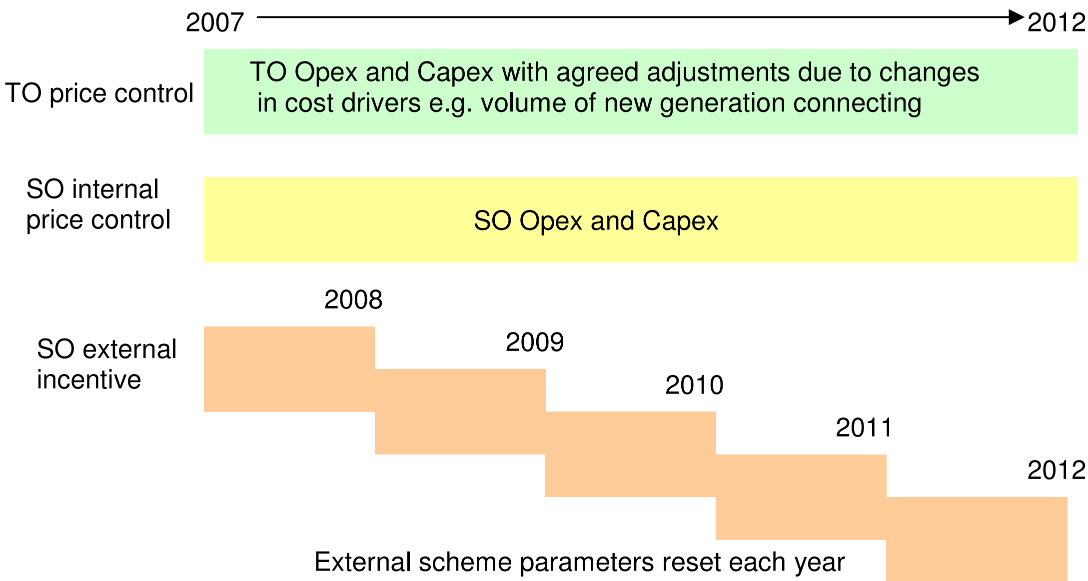

Figure 3: TO and SO Price control periods

16 As can be seen in Figure 3, the SO Internal Opex and Capex targets are agreed for a five year period at the Price Control Review with the BSIS target and sharing factors being agreed on an annual basis. With this arrangement any efficiency improvements of external costs created by any innovation (which may for example increase internal costs) are rolled up in to subsequent years target's and the innovation is only rewarded in a single year.

17 These agreed sharing factors for the BSIS incentive are also applied to the internal SO incentive scheme for each year. The current internal SO incentive scheme therefore contains an upside sharing factor of 25% and a downside sharing factor of 15% against targeted costs. However, unlike the BSIS incentive, as detailed in section 1.4, there is no deadband, caps or collars.

18 For activities that are deemed Transmission Owner (TO), a different incentive arrangement is in place. A target allowance was set at the last TPCR but (effectively) with 100% sharing factors as National Grid is wholly exposed to opex increases or decreases around this allowance. Therefore, any costs incurred by the TO in reducing operation costs (such as extended working to reduce the exposure to constraint costs) has a 100% impact on the TO costs. Potential issues with different sharing factors and hence "incentive rates" between TO opex costs and SO opex / balancing costs was discussed as part of the Potential Enhanced Electricity Transmission Owner (TO) Incentives, detailed in section 1.6.

19 In the transmission licence the external BSIS costs are referred to as the Incentivised Balancing Costs (IBC) and can be defined as follows;

$$\mathbf{IBC = [\ CSOBM + NIA + BSCC + TLIC\ ] + [\ minor\ terms\ ]} \qquad \mathbf{(1)}$$

Where

Acronym	**Full Description**
IBC	Incentivised Balancing Costs
CSOBM	Cost to System Operating for the BM
NIA	Net Imbalance Adjustment
BSCC	Balancing Services Contract Costs
TLIC	Net Cost of Transmission Losses
Minor Terms	The minor terms are other costs associated with the balancing services, which are relatively small in comparison to the other terms.

20 External BSUoS can be expressed as the following

$$\mathbf{BSUoS_{(ext)} = CSOBM + BSCC + Incentive\ payment} \qquad \mathbf{(2)}$$

21 Combining and rearranging terms allows the relationship between external BSIS and external BSUoS costs to be defined by the following equation;

$BSUoS_{(ext)}$ = IBC – NIA – TLIC + Incentive payment (3)

22 As can be seen by equation 3, the performance of the BSIS will directly affect the BSUoS costs charged to CUSC participants. For this reason, the performance of National Grid against the target set out in the BSIS should be of interest to the industry.

BSUoS = $BSUoS_{(ext)}$ + Internal SO costs + Internal Incentive payment (4)

23 Equation 4 shows the overall BSUoS costs. As can be seen, BSUoS costs are made up of BSUoS external costs (costs of balancing the system) plus the internal SO costs with the external and internal incentive payment.

24 Responses received during the consultation process indicate there is a level of interest present within the industry. National Grid is working with industry participants to increase engagement in discussion of the future drivers and costs, along with suitable incentive mechanisms that reflect these.

1.4 The 2009/10 BSIS

1.4.1 Overview of Current Scheme

25 The 2009/10 BSIS has been under way since April 2009. The current BSIS combines all balancing components (i.e. constraints and reserve, amongst others) into a single bundled scheme with overall performance dependent on the management of all aspects of the bundled components.

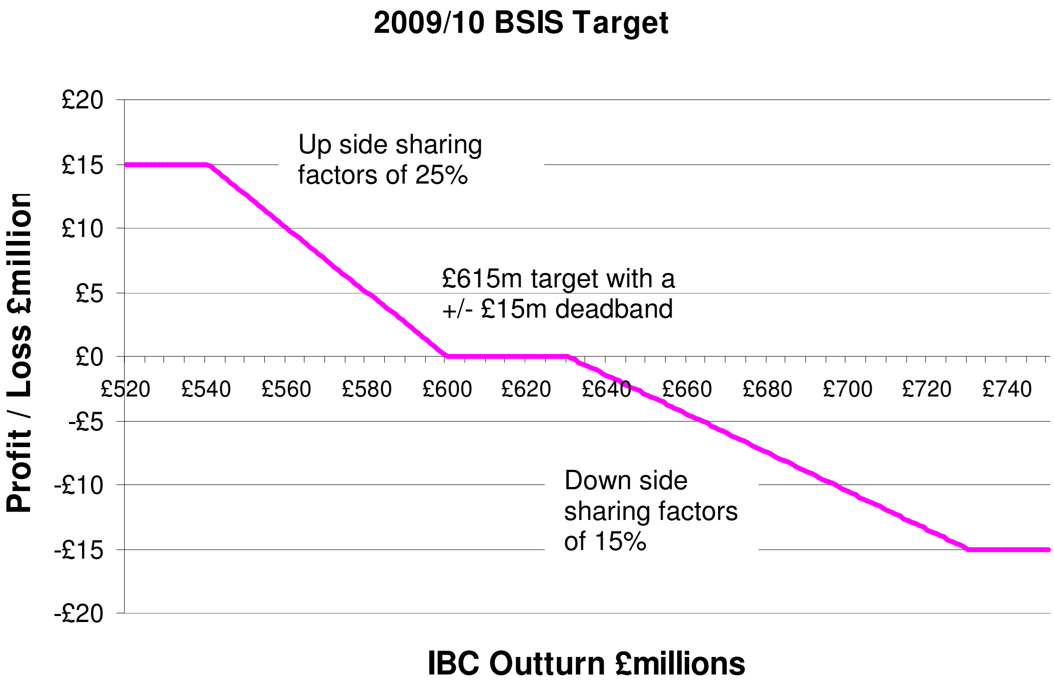

Figure 4: BSIS Profit / Loss Profile 2009/10

26 Figure 4 shows the incentive arrangements in place for the start of the 2009/10 scheme. Where BSIS costs vary away from the target, the industry and National Grid share in the benefits or disbenefits.

27 The current scheme contains an upside sharing factor of 25%; this means that for every £1 reduction in costs below the lower boundary of the deadband, the industry share the benefit with National Grid 75% to 25%, i.e. the industry receives 75p and National Grid receive 25p up to the scheme profit cap of £15m. Should costs be reduced beyond the scheme profit cap then 100% of the saving would be passed to the industry. For outturn above the upper level of the deadband, the industry and National Grid share in the disbenefit, with National Grid paying 15% of the costs up to a maximum of £15m.

28 The asymmetrical sharing factors were initially proposed by National Grid to reflect the asymmetrical cost risk profile of the scheme (as shown in Figure 4). This asymmetry occurs due to the impact of low probability high cost events such as extreme weather conditions (for example, a 1 in 20 winter that would produce very cold conditions significantly increasing margin costs) driving costs up more than costs would be decreased by a similar low probability events (such as a 1 in 20 warm winter that would produce mild conditions).

29 For the 2009/10 incentive, there were a number of uncertainties in key assumptions. To address these uncertainties, a methodology was agreed with Ofgem that would adjust the scheme target if the events differed from these key forecast assumptions. There have been some

changes in these key assumptions that have instigated these adjustments.

30 These changes are associated with delays in the implementation of Congestion Management Guidelines on the French interconnector and the delayed closure of major demand-side provider of balancing services.

31 We have recently written to Ofgem to formally request a reduction in the agreed BSIS target in line with these changes. The changes in these key assumptions from those agreed prior to the start of the incentive scheme result in a reduction in the target costs (and deadband) of £13.6m as shown in the graph below. Adjustments to the scheme will require agreement from Ofgem and subsequent licence change to reflect the proposed changes.

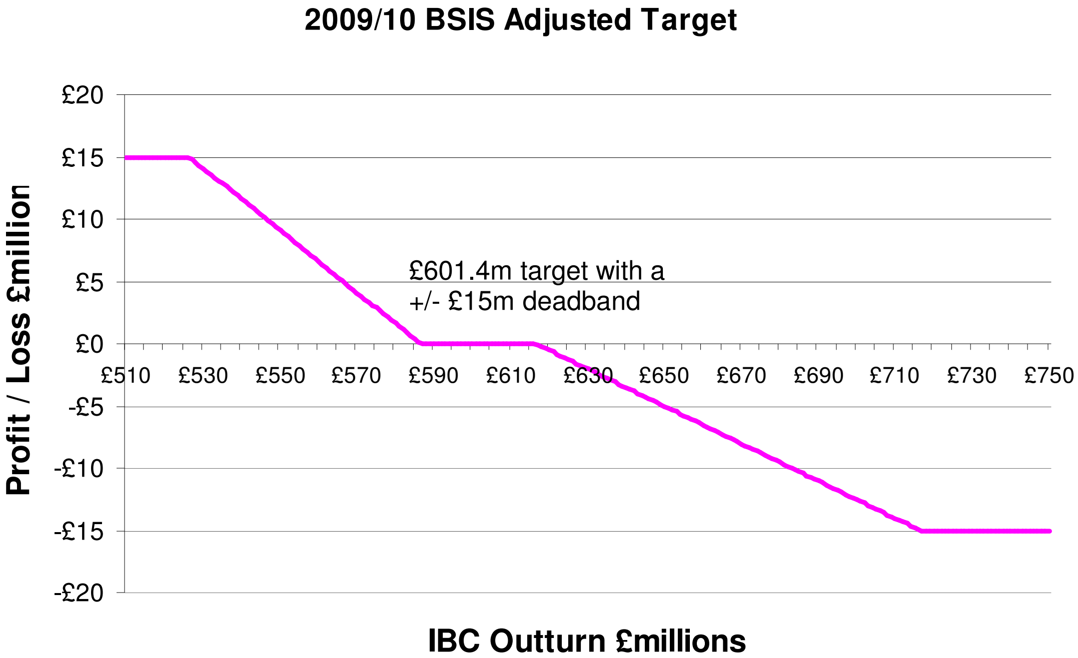

Figure 5: Adjusted BSIS Profit / Loss Profile

32 Figure 6 shows the BSIS forecast figures on which the scheme was based, the latest forecast figures, the monthly outturn figures and the cumulative monthly forecast for this scheme. The “scheme forecast” in Figure 6 was produced in February 2009 and was used as the basis by Ofgem in the final proposals for the 2009/10 BSIS.

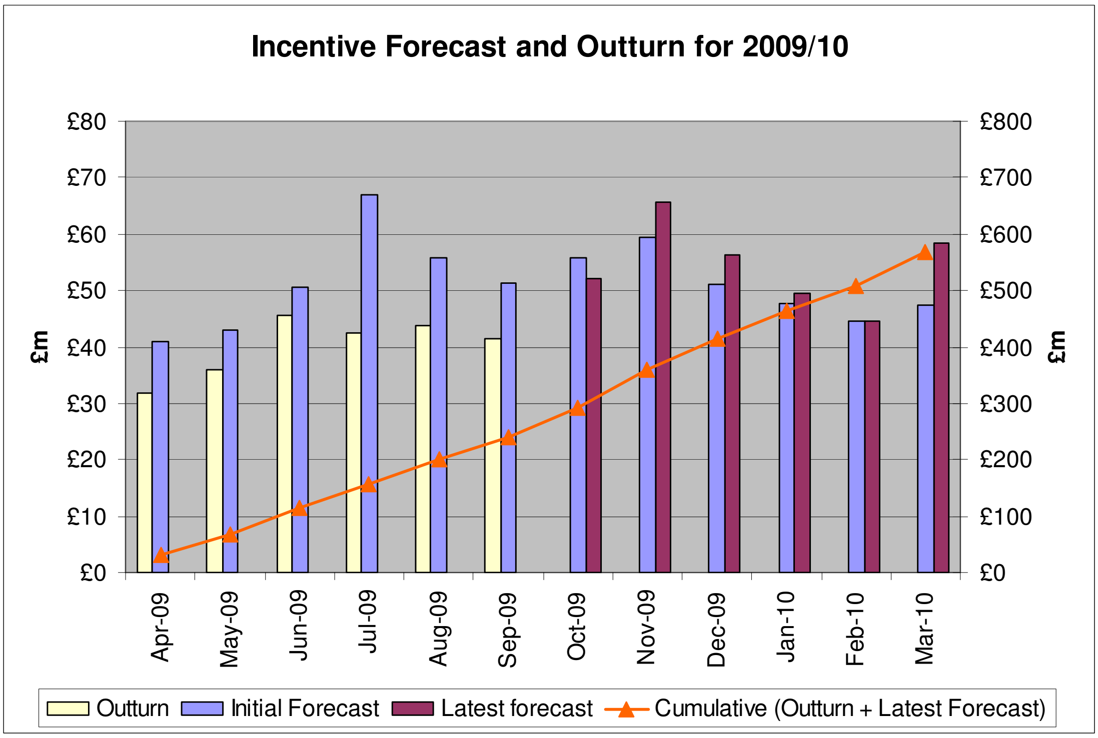

Figure 6: Monthly Incentivised Balancing Costs forecast & outturn

33 Figure 6 was presented and discussed with industry participants at the Electricity Operational Forum, held on the 7th October 2009.

34 Since the start of the 2009/10 BSIS, National Grid has successfully managed to lower BSIS outturn costs by approximately £50m. Three of the more significant BSIS savings have been made by securing the following actions (actual costs are not included due to commercial sensitivity);

- A successful contracting strategy to reduce constraints costs
- Securing more efficient ancillary services contracts
- Optimising the dynamic calculation of reserve requirements

35 Constraint costs have outturned lower than forecast due to successful contracting strategies aimed at limiting the output of generation behind critical system boundaries. Also, a number of power stations have been contracted to provide new intertrip facilities, which is also contributing to lowering constraint costs.

36 National Grid's negotiation strategy to secure Firm Frequency Response (FFR) for the next 18 months further contributed to reducing incentivised balancing costs (IBC) throughout 2009/10.

37 National Grid has developed a new technique to optimise its reserve requirement calculation and give a variable requirement which changes with the Net Imbalance Volume (NIV). This results in the reserve

requirement being calculated dynamically to account for market length resulting in an overall cost saving.

38 In addition to the reduction in costs achieved by actions taken by National Grid, lower BSIS costs have outturned due to the market being long compared to the anticipated level. This has resulted in a reduction in operating reserve costs, due to a lower volume of BSA being required.

39 Although cost reductions have been achieved elsewhere in the 2009/10 BSIS, footroom costs have outturned higher than originally forecast due to:

- An increase in inflexible generation running at periods of low demand. This is a result of high nuclear availability and an increase in wind generation.

- Low gas prices resulting in gas-fired generators running overnight at minimum output rather than desynchronising overnight.

40 To mitigate the effects of increasing footroom costs, National Grid has taken a number of actions, including extensive use of pre-gate actions to achieve lower prices than those in the BM; the assessment and recalibration of high frequency response parameters[2] resulting in a reduction in the volume of bids and offers required in the BM; and the sale of energy via the French interconnector which effectively raises system demand as an alternative to desynchronising generation.

41 Presently, the cumulative incentivised costs for 2009/10 BSIS are expected to outturn at around £570m, as shown in Figure 6. Taking into account the proposed changes to the BSIS scheme target costs set out in paragraph 30 above and, if National Grid continues to perform as per the cumulative outturns displayed in Figure 6, National Grid will retain a profit share of around £4m to £6m, due to actions taken to reduce costs of system operation.

1.5 The Consultation Process

42 Via an open letter, published on 28 May 2009[3], Ofgem has asked National Grid to lead on the development of initial proposals for the implementation of System Operator (SO) incentives commencing April 2010. The letter summarises Ofgem's views on the objectives, process and timetable for this year's consultation. National Grid's response to this letter can be found on the National Grid website[4].

[2] The parameters used to convert a response requirement into a volume of actions required is discussed in more detail in section 3.2.4.1

[3] http://www.ofgem.gov.uk/Markets/WhlMkts/EffSystemOps/SystOpIncent/Documents1/Open%20Letter%20final.pdf

[4] http://www.nationalgrid.com/NR/rdonlyres/D68DE8C6-DB21-4513-B60E-98B3AE709305/35809/SOInitialProposalsTimetableNGOpenLetter.pdf

43 In this letter, Ofgem recognised the valuable contribution made by the industry in developing the incentive scheme implemented in April 2009 and go on to state that they are keen to further promote engagement from industry participants, end consumers and smaller suppliers in this year's process. In response, National Grid has presented at a number of industry meetings and arranged bilateral discussions with interested parties to highlight the issues for this year's consultation. A generic copy of the slides used at these meetings can be found on National Grid's website.[5]

44 If you would like National Grid to present at any future meeting or would like to meet on a one to one basis to discuss this year's consultation, then please contact us using the contact details at the end of this document.

45 As outlined in Ofgem's open letter, there were a number of key issues that needed to be addressed to facilitate the development of robust Initial Proposals. These issues were addressed by publishing three independent mini consultations, which discussed the development of SO incentives. The topics of each of the mini consultation was as follows;

- Transmission Losses, Reactive Power and Black Start
- Energy Related Components
- Constraints

1.5.1 Transmission Losses, Reactive Power and Black Start Mini Consultation

46 This Mini Consultation discussed a number of themes associated with transmission losses, reactive power and black start contracts. The costs associated with transmission losses, reactive power and black start contracts contribute approximately 7% of the forecasted total BSUoS costs for 2009/10, as shown in Figure 2. The key themes are summarised below.

47 This consultation discussed National Grid's level of control over transmission losses along with the appropriateness for National Grid to be incentivised to manage them. In light of these discussions, alternative methodologies to incentivise management of Transmission losses were proposed and evaluated, which could be developed in future incentive schemes.

48 The development of a multi-year scheme and of a reactive power index was discussed in the reactive power section of this consultation. Questions to the industry were posed about the perceived benefits that could be achieved by unbundling the reactive power incentive from the rest of the BSIS.

[5] http://www.nationalgrid.com/uk/Electricity/soincentives/AnalystArea/

49 The black start section of this consultation identified the changes that are required over the next two to five years in light of the changing generation background. The costs associated with black start provision are expected to increase; hence the views of the industry were sought regarding the developments that could be made to the black start incentive to reflect these changes.

50 Six responses to the Transmission Losses, Reactive Power and Black Start Mini Consultation were received. In general there was support for the indexing of reactive power prices, but limited support for the unbundling of any of these incentives from the main BSIS. There was limited industry support for options, which had the potential to increase volatility of costs and Income Adjusting Events (IAE).

1.5.2 Energy Related Components Mini Consultation

51 The Energy Related Components Mini Consultation discussed the key issues surrounding the development of longer term incentive schemes plus the benefits of and reasons for unbundling the energy related components from the rest of BSIS.

52 The energy related components considered in this mini consultation were: energy imbalance, margin, footroom, response and fast reserve. These components account for 58% of the forecast total BSUoS costs for 2009/10, as shown in Figure 2 . This consultation presented the drivers that impact energy component costs and sought industry views as to the level of control National Grid has on each. Developments to the formulation of NIA were presented and discussed.

53 Six responses from the industry were received in reply to this mini consultation. In general there was limited support for options, which had the potential to increase the volatility of costs and IAE; specific questions were asked regarding their implications. Mixed views were received regarding the potential developments to NIA, and whether its formulation should be made more transparent and simple or optimal fit and more complex.

1.5.3 Constraints

54 Constraint costs contribute to 22% of the forecast total BSUoS costs for 2009/10, as shown in Figure 2. The mini consultation considered alternative treatments for the constraint component of BSIS. Key drivers of constraint volumes and costs were discussed and the options for and implications of an unbundled scheme were discussed. The development of adjustment terms to allow the scheme target be updated according to key factors was proposed. Alternative methods to treat fault outages were presented for discussion. As in the other mini consultations, the potential for a longer term incentive scheme was discussed.

55 Six responses were received from the industry in reply to the Constraints Mini Consultation. Mixed views were received; whilst a majority view did not support the proposals for un-bundling constraints from BSIS or any options, which had the potential to increase the volatility of costs and IAE or the development of the adjustment terms. However, some support for these suggestions were received.

1.6 The Potential Enhanced Electricity Transmission Owner (TO) Incentives

56 National Grid has recently published an informal consultation to the industry, entitled The Potential Enhanced Electricity Transmission Owner (TO) Incentives[6]. The purpose of this document was to consult the industry about the potential benefits in pursuing a range of initiatives.

57 The ideas discussed in The Potential Enhanced Electricity Transmission Owner (TO) Incentives Consultation interact strongly with the achievement of broader government energy policy objectives, the reform of transmission access arrangements and the development of the SO incentives presented in this document.

58 Seven responses were received in reply to the Potential Enhanced Transmission Owner Incentives Consultation, a copy of these can be found on the National Grid website[7]. A high-level summary of the consultation and responses is presented below.

59 Chapter 3, "Investment Incentives for Grid Connections", proposed an enhanced investment incentive in England and Wales to complete local works in faster than normal timescales.

60 Respondents identified no compelling need to revisit the existing incentives on local works for Scottish Transmission Owners that were established via the last transmission price control. Some respondents suggested that changes to the England & Wales arrangements may be appropriate and desirable, subject to further analysis on the potential benefits, but that it was important to ensure that the design of such a scheme aligned with the provision of wider works and SO constraints.

61 National Grid proposes that further analysis on the potential benefit for an enhanced investment incentive for local works in England & Wales should be undertaken.

[6] http://www.nationalgrid.com/NR/rdonlyres/FB4A9925-15AB-462A-B516-33543A44B460/37082/PotentialEnhancedElectricityTransmissionOwnerIncen.pdf

[7] http://www.nationalgrid.com/uk/Electricity/soincentives/docs/

62 Chapter 4, “SO/TO Interface Issues”, considered improvements to the way the System Operator co-ordinates and changes outage plans with both the Scottish and England & Wales Transmission Owners.

SO-driven Capital Expenditure on Scottish TOs:

63 There was support from the Scottish TOs for a ring fenced Capex allowance that could be used for SO driven projects, and drawn down on a case by case basis, although it was noted that such work should not compromise essential reinforcement projects. There was less support from respondents for an equivalent scheme in England & Wales.

64 National Grid proposes that further work be undertaken in this area, noting that any fund should be transparent and appropriately justified through cost-benefit analysis.

SO/TO Interaction in England and Wales:

65 There was broad support for addressing those differences between the SO and TO incentives that could give rise to perverse incentives. Respondents were of the view that aligning the incentive structures should promote a more optimal approach to managing constraints across both SO and TO activities.

66 National Grid proposes that further work be undertaken in this area.

Extending the Duration of the Final Outage Plan:

67 There was some support for extending the current duration of the final outage plan from one to two years (to provide greater scope for outage optimisation) and allowing any change costs to be funded over this extended period. Some respondents noted the importance of ensuring the funding arrangements deliver the correct outage planning behaviour.

68 National Grid considers that further analysis is required to determine the benefit of extending the outage change allowance to also cover England & Wales, including the required magnitude of such a fund and who would ultimately bear the cost.

69 Chapter 5, “Aligning TO and SO Incentives”, considered, at a high level, ways of incentivising TOs to help manage constraint costs. Three potential approaches were discussed – (1) incentivising specific outage change activity, (2) incentivising the availability of transmission capacity and (3) incentivising minimisation of network constraints.

70 There was little support from respondents for any of the explicit incentive models presented, with some wary of creating incentives that reward licensees for simply for meeting the terms of their licence, and possibly to the detriment of their normal baseline performance. The general view was that developments in this area would require detailed consideration,

precluding implementation in the shorter term, with a preference for any such incentives to be introduced at the start of a new price control period.

71 National Grid considers that further analysis is required to identify potential benefits in this area, noting the interaction with the forthcoming transmission price control reviews.

72 We are in the process of considering the consultation responses in detail and will communicate our proposals for taking work forward in the near future. The clear interaction between this work and the development of SO incentives for constraints will be carefully considered going forward.

1.7 Industry responses to consultations

73 All industry responses have been gratefully received and reviewed during the development of these proposals. It is hoped that further industry feedback will help to improve and develop the initial proposals into the final proposals, such that they better reflect the opinions of the industry.

1.8 Development of a 'Fixed Price' BSUoS methodology proposal

74 At the Transmission Charges Methodology Forum (TCMF)[8] on 30th September 2009, Centrica presented a methodology for reducing the volatility of balancing charges[9]. Centrica's proposed methodology smoothed BSUoS charges within year by charging 1/12th of each of the previous 12 months' outturns in a given month.

75 A number of comments were received at the meeting on the proposal which Centrica undertook to take away for further consideration.

[8] The TCMF is an industry forum that discusses National Grid's charging methodologies and the principles behind them. The aim of the forum is to allow Users to become involved in the development of the charging methodologies and enable National Grid to keep them under constant review. All existing or prospective Connection and Use of System Code (CUSC) parties are eligible to send one representative to the meeting.

[9] The presentation can be found at the following link http://www.nationalgrid.com/NR/rdonlyres/DC114EB8-D0BC-4745-ABCF-F4CAC8F573A3/37279/TCMF_presentation_30092009Centrica.pdf The minutes of the meeting can be found at the following link http://www.nationalgrid.com/NR/rdonlyres/FB206939-9C1D-422E-9E4C-1FA92C8461CC/37432/300909TCMFMeetingRepDraftv02.pdf

Section 2
Balancing Services Components

This section sets out the components from which Balancing Services costs are incurred. It also describes the relationship and drivers of these various areas thus providing an overview of BSIS costs.

2.1 Introduction

76 The costs within the Balancing Services Incentive Scheme (BSIS) are formed by the following components, representing actions taken by National Grid in our role as system operator:

- Energy Related Components
- Reactive
- Minor components (including Black Start and Transmission Losses)
- Constraints

77 Costs for operating the system are classified (e.g. split between energy, margin, response, constraints, etc) according to our internal Balancing Actions Autopsy Report (BAAR) costing methodology.

78 This chapter provides an overview of each of these cost components and a description of the drivers affecting them. The next chapter will provide a detailed explanation of the assumptions for each of the most relevant drivers utilised for forecasting the costs of the BSIS starting in April 2010.

2.2 Overview of the energy related cost components

79 Energy related components refer to the costs incurred by National Grid to balance generation and demand, maintaining the system frequency at 50 Hz. An excess of generation relative to demand causes frequency to increase, while lack of generation relative to demand causes frequency to decrease.

80 These components capture actions taken by National Grid to match generation and demand, and hence system frequency, taken at different time scales, as shown in Figure 7 below.

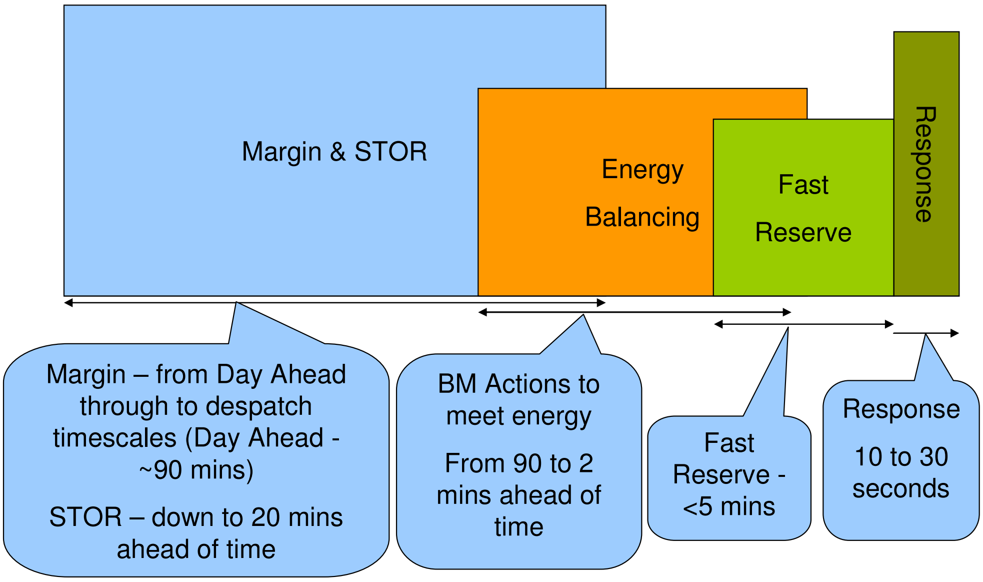

Figure 7: Actions taken in different time scales to manage system frequency

81 An overview of each component is given below with a description of the main drivers in section 2.5. A more detailed explanation of each cost component can be found in Appendix B of our Consultation Document on Developments of the Incentive for the Energy Related Components (2/09)[10] and at National Grid's website: http://www.nationalgrid.com/uk/Electricity/Balancing/services/.

2.2.1 Energy Imbalance

82 Energy imbalance costs are those incurred by National Grid to correct for differences between the generation supplied by the market and the demand on the system. The following actions are taken to ensure that generation and demand are balanced:

- buying and selling power in the BM (otherwise known as offers and bids);
- pre-gate closure balancing transactions (PGBTs); and
- trading, either through over the counter negotiations or through the energy exchange market, APX.

83 The volume of energy imbalance actions is also known as Net Imbalance Volume (NIV) and is often referred to as market length[11].

84 The price of energy imbalance actions is dependant on the submitted (and accepted) prices in the BM (due to the large number of actions

[10] http://www.nationalgrid.com/NR/rdonlyres/95D86B42-F2A4-4317-83D5-551F9AE27D7E/36514/Energyconsultation_final.pdf

[11] TQEI and NIV both measure market imbalance (length), albeit via different methods. TQEI is calculated in the settlement stage as the sum of all participants' energy imbalance, while NIV is calculated in operational timescales as the sum of all actions taken by National Grid. A valid approximation is TQEI = -NIV.

taken in the BM), which hold a relationship with the prevailing wholesale power price as illustrated in section 2.5.

2.2.2 Net Imbalance Adjustment (NIA)

85 The Net Imbalance Adjustment (NIA) is a factor aimed at minimising the incentive scheme exposure for changes in power price and market length, minimising the possibility of windfall profits and losses in the incentive scheme as a result of changes in parameters outside our control.

86 NIA is added to the actual balancing services costs for the calculation of the Incentivised Balancing Costs (IBC), as defined in National Grid transmission licence:

87 NIA is calculated on a half-hourly basis as a function of wholesale power price and market length. For the current incentive scheme (2009/10), a revised NIA calculation was introduced with the formula:

NIA = 450 x SPNIRP + 0.9 x SPNIRP x TQEI, for long market periods
NIA = 450 x SPNIRP + 1.25 x SPNIRP x TQEI, for short market periods

Where
- SPNIRP is the Single Net Imbalance Reference Price, calculated according to the transmission licence
- TQEI[12] is the Total System Energy Imbalance Volume, as defined in the Balancing and Settlement Code

2.2.3 Margin

88 Margin costs are incurred when National Grid synchronises additional units onto the system in order to ensure that the Short Term Operating Reserve Requirement (STORR) is met. The STORR is set such that there is a risk of only 1 in 365 days that total demand will not be able to be met. Setting STORR is a fine balance: demanding a lower risk implies a more expensive system operation; achieving cost reduction through the reduction of this requirement implies an acceptance of higher risk of demand disconnection

89 The volume of margin actions is dependent on the system conditions in relation to the STORR requirements. For instance, the headroom created by reducing output from self-despatched generation units in longer markets reduces the need to take margin actions (see section 3.2.7.1).Another input is the variation in output from intermittent sources. This energy needs to be supplied from alternative sources when the

[12] TQEI and NIV both measure market imbalance (length), albeit via different methods. TQEI is calculated in the settlement stage as the sum of all participants' energy imbalance, while NIV is calculated in operational timescales as the sum of all actions taken by National Grid. A valid approximation is TQEI = -NIV.

intermittent source is unable to. In shorter timescales this potential shortfall contributes to STORR.

90 Operationally, costs related to meeting STORR are called Margin actions. There are two basic mechanisms to achieve STORR: Operating Reserve actions and contracting of Short Term Operating Reserve (STOR) units.

91 The first mechanism is acted by the purchase of power from units not scheduled to be connected in the system at the required time. These actions are expected to cause either the additional synchronisation of such units or the advancing of synchronisation time of units that were already planned to connect, or the delaying of the de-synchronisation time of units already connected in the system. These Operating Reserve actions can be operated either in the form of offers in the BM or as PGBTs and Trades, in the main these actions come from offers in the BM.

92 The price of offer prices in the BM hold different relationships with different drivers dependent on the fuel type of the unit utilised. For instance, offer prices from coal fired units have a strong relationship with wholesale baseload power price, whilst offer prices from gas fired units are more closely related to the wholesale clean[13] gas prices. The relationships are further explored in section 3.3.5.

93 The second mechanism to achieve STORR is the contracting of relatively fast acting standby generation through STOR tenders. STOR units can be either BM participants or not. Such units are paid availability fees and utilisation fees.

94 Two additional items fall within the “Margin” cost group: BM Start Up and Constrained Margin Management actions.

95 BM Start Up relates to actions taken by National Grid to position generation units with longer notice times into a state of readiness through “warming” the units.

96 Constrained Margin Management (CMM) relates to additional operating reserve actions taken only partially due to the sterilisation of operating reserve (headroom) caused by active transmission constraints. Therefore, if an operating reserve action taken in a given generation unit is deemed to be completely for the replacement of sterilised headroom behind a constrained boundary, then it is assigned as a constraint cost; otherwise, if only part of the created headroom is deemed to have been necessary for sterilised headroom replacement, then the cost is assigned as CMM, as illustrated below:

[13] Clean gas prices refer to the fuel price corrected by the carbon emission price in the EU ETS.

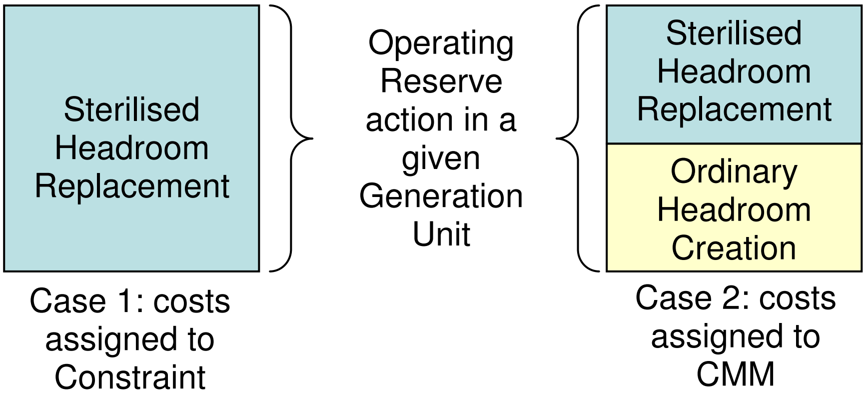

Figure 8: Operating Reserve actions assigned to Constraints or to CMM

2.2.4 Footroom

97 Whereas Margin actions are those that enable National Grid to increase generation to higher than expected demand levels, Footroom (or downward regulation) actions are those taken to reduce the amount of generation connected in the system so that frequency can be safely managed in periods of lower than expected demand.

98 The level of footroom available becomes an issue particularly at times of low demand, when the majority of flexible generation is at its minimum stable output. Footroom costs are related to the de-synchronisation of some units at their minimum stable level in order to increase other units (i.e. to move them away from their minimum stable output such that they can act in response to changes in frequency).

99 The volume of footroom actions required is significantly impacted by the availability and running regimes of generation, in particular inflexible types such as nuclear and wind. High levels of inflexible generation generating during periods of low demands often sees flexible generation moving toward their minimum stable output (as would be expected from the relative merit order running of such generation), increasing the volume of actions required.

100 The price of footroom actions is relatively stable, as most actions tend to be taken overnight in the summer (lower demand periods), when power prices tend to also be stable. This is discussed further in section 3.3.4.2

2.2.5 Response

101 Response costs are incurred by National Grid to instruct providers (generators and demand units) to act in a frequency responsive mode, i.e. changing their output or offtake automatically according to the system frequency for which they receive capability and response energy payments. The amount of generation and demand held in this frequency responsive mode is a function of the largest possible immediate loss of generation and demand and the maximum acceptable frequency excursion in such event.

102 National Grid incurs two main costs by performing such actions: the cost of positioning the units in the responsive mode (bids and offers in the BM) and the usage fee charged by the generators to act in such mode (tendered).

103 In the case of the cost of positioning the units in the responsive mode, the prices submitted are related to wholesale power prices. A full discussion is to be found in sections 3.3.4.1 and 3.3.6.1. In the case of fee charged by the generators to act in such mode, prices are dependent on those submitted via the Frequency Response Price Submission (FRPS) system for mandatory response and tendered/contracted prices for commercial frequency response provision.

104 Special contracts exist to minimise National Grid's cost (or risk of increased cost) of positioning the units in frequency response mode, namely the Firm Frequency Response (FFR) and Part Loaded Response (PLR) contracts.

105 The above described mechanism is provided by dynamic response providers. A certain proportion of frequency response can also be achieved with the immediate disconnection of large demand units, the so called 'static' response providers. With such providers there is typically only a fee associated with usage.

2.2.6 Fast Reserve

106 In the event of an incident involving generation disconnection, frequency response units will act immediately to stabilise frequency within acceptable limits. Control engineers will issue instructions to re-despatch generation so that a new steady state balance can be achieved; however, those actions have a natural delay time, dependant of the dynamics of the available generation at the time of the incident. In order to achieve a more promptly re-establishing of frequency and restore the system frequency response capability, National Grid need to use units with enhanced dynamic characteristics.

107 Additionally, in the event of rapid demand changes, such as those experienced during "TV pickups", National Grid will utilise the enhanced capabilities of fast acting units.

108 Fast Reserve costs relate to the contracting and use of such generation and demand units. Fast reserve prices are mostly dependent on tendered (and accepted) prices, submitted by service providers.

2.3 Reactive Power

109 Reactive power production and consumption results from electricity transmission using alternating current. Reactive power is managed on a locational basis through the generation and absorption of Mvars[14] and is essential for maintaining voltage levels within designated limits across the transmission system. More details on reactive power can be found in section 3 of our Consultation Document 1/09[15].

110 Within the BSIS, reactive power relates mostly to the volumes procured by National Grid from generation units. The requirement for generators to provide reactive power is defined in the Grid Code. The required output level at any given time from the generator is determined by National Grid and is generally used to optimise the transmission network voltage profile. The volume of reactive power procured by National Grid depends on the system demand and the overall configuration of the transmission system at that time.

111 There are two types of arrangement by which reactive power can be procured from a generator: default arrangements and market arrangements.

2.3.1 Reactive Power Procurement Default Arrangements

112 For generators that have not entered a market agreement with National Grid, the generator will be paid using the default arrangements outlined in the Connection and Use of System Code (CUSC). This mechanism is for generators that meet the Grid Code requirements (CC6.3.2) for reactive power provision and are requested by National Grid to provide reactive power services. The current arrangements are based on the generators metered reactive power volumes (i.e. utilisation only) and paid using a reactive power default price which is defined within the CUSC as a function of wholesale prices and Retail Price Index. The same payments apply to both absorption and generation of reactive power.

113 More detail can be found under Schedule 3 Part 1 of the Connection and Use of System Code (CUSC)[16].

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[14] A var is the unit of reactive power with a Mvar being a million vars.
[15] http://www.nationalgrid.com/NR/rdonlyres/7C4BD8DD-E71B-48F5-95E9-B611AD73CB9D/36153/ElectricitySOIncentivesConsultation.pdf
[16] http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/contracts/

2.3.2 Reactive Power Procurement Market Arrangements

114 This service is open to transmission users with and without a Grid Code obligation to provide reactive power. There are two forms of this arrangement: "Obligatory Reactive Power Service" and "Enhanced Reactive Power Services". The market arrangements enable the reactive power provider to request via a tender process:

- an available capability price; and/or
- a synchronised capability price (£/Mvar/hr); and/or
- a utilisation price (£/Mvarh); plus
- choice of contract length (from a minimum period of 12 months and thereafter in 6-month increments (12, 18, 24, 30, 36 months, etc.))

115 Reactive power volumes and costs procured under the market arrangements form a small percentage of overall volumes procured (approximately 7% in 2008/9).

116 More detail can be found under Schedule 3 Part 1 of the Connection and Use of System Code (CUSC).

117 There is additional information on the procurement of reactive services on our web site:

http://www.nationalgrid.com/uk/Electricity/Balancing/services/ReactivePower/

2.4 Minor Components

2.4.1 Black Start

118 National Grid has an obligation under the Grid Code to ensure that the transmission networks can be re-energised in the event of a total or partial system shutdown. Such re-energisation is known as black start.

119 Despite the low likelihood of a total or partial system shut-down occurring, contingency arrangements must be in place to enable a timely and orderly restoration of supplies.

120 National Grid's obligation is met by contracting with generating stations to be able to re-start generation without a power in feed from the transmission system; ensuring transmission equipment can be operated in the absence of external supplies and by agreeing contingency procedures with generators and network operators. There is no obligation upon generation to provide black start services.

121 The costs for black start are dependant on contract costs which may include availability fees, capital contributions and testing fees.

2.4.2 Transmission Losses

122 A small percentage of the energy transferred over the GB electricity transmission system is lost due to the physical process of transmitting electricity. This 'lost' power is known as transmission losses and is currently around 1.7% of the power transmitted.

123 Transmission losses are not a cost that National Grid is directly exposed to in relation to balancing the system. However, National Grid is incentivised to minimise losses as part of BSIS.

124 To convert the transmission loss volume into a cost, the current incentive uses a reference price. The transmission losses reference price is based on the forward price plus an adjustment to replicate the shadow price of carbon[17] (as implemented in 2008/09).The shadow price of carbon adjustment was calculated using the differential between the market price of carbon and the shadow price of carbon taking into account the relative generation types and efficiencies. The forward price used was £47.09/MWh (the average forward price for 2009/10).

125 Figure 9 shows the level to BSIS adjustment, for 2009/10, for a range of potential transmission losses outturns against the 6.0TWh target and 0.2TWh deadband (x-axis).

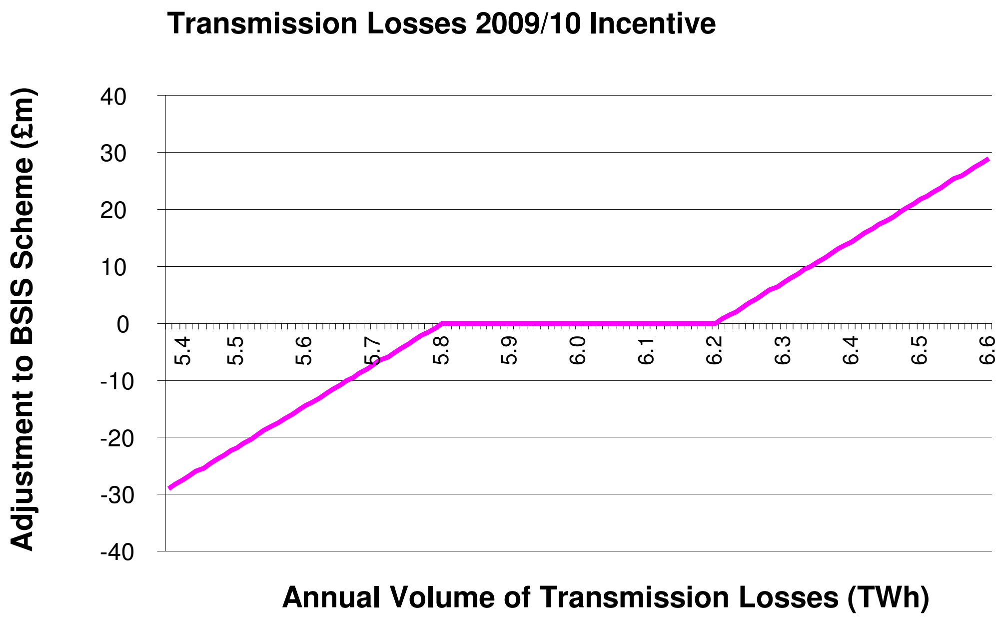

Figure 9: Calculation of Transmission Losses adjustment

[17] http://www.defra.gov.uk/environment/climatechange/research/carboncost/pdf/HowtouseSPC.pdf

126 As can be seen, as the transmission losses outturn moves away from the agreed target, the BSIS adjustment shown on the y-axis quickly ramps up to significant levels. The graph shows that for a 10% change in losses volumes, there is a £29million impact on the BSIS scheme.

2.5 Cost drivers of Energy, Reactive, Black Start and Transmission Losses:

127 National Grid is incentivised through the BSIS to reduce the cost of operating the transmission system. Such costs are dependent on a number of factors, each with different degrees of predictability and volatility and also the level of control that National Grid can express in that area. This section outlines the main cost drivers, with a brief description and our view on how controllable, predictable and volatile they are.

128 The cost of energy component actions are the result of the volume of services required and the price of these services. Their main drivers are:

- Electricity wholesale market price
- Balancing Mechanism (BM) prices
- Balancing Services Contracts
- Volume of Wind generation
- Level of market imbalance (market length)
- Generator availability and operating regimes
- Requirements for services to comply with NETSSQSS

129 Reactive power costs share the driver of wholesale power price. Additional drivers are:

- RPI
- Level of active power flows across the transmission system
- Customer Reactive Power Demand
- Commercial Reactive Power contracts
- Reactive power dispatch

2.5.1 Electricity Wholesale market price

130 One important driver of the costs incurred by National Grid to manage system frequency is electricity wholesale market price. Market price impacts the cost of pre-Gate trades, BM actions and the volume and direction of flows across the Anglo-French interconnector.

131 Wholesale power price is also a strong driver of reactive power costs as almost the totality of reactive power is purchased using the default arrangements. The default price is defined in CUSC Schedule 3 Appendix 1[18] and is calculated monthly based on the relevant month's RPI and month ahead wholesale power price. This process ensures that power price is accurately reflected in accordance to the most up to date data available.

132 Whilst the prices to which National Grid is exposed for managing system frequency have a half-hour granularity and the reactive power default prices are calculated monthly, the current incentive target is based on forward power price that is looking up to 16 months ahead. Utilising forward market price curves have the advantage of using a relevant external, transparent and well understood market based index representing the current value of energy for the period in question; if all balancing actions were performed at this moment the price quoted would be that paid, save for any premiums on specific services. However, the uncertainty of power prices introduces a risk into the forecast and can also lead to windfall gains and losses for changes in power price away from the forward price in the future.

133 Figure 10 illustrates the change in forward prices over time compared to the outturn. The range has been developed comparing forward power prices and day ahead price. The P90 and P10 lines indicate the statistical boundaries for the accuracy of forward power price as an indication of value the market will reach by the day ahead power stage. There is a 10% chance that day ahead price will be below the P10 range and a 10% chance that the day ahead price will be above the P90 range. Therefore, there is an 80% chance that the day ahead price will be within the P10 – P90 range. As can be seen, the range of day ahead power prices when compared to the year ahead forward price increases the farther ahead the forward power price forecast has been used. The graph indicates that:

- at 4 weeks ahead the ability to use forward power prices as an indication of short-term prices sits within a range of around +30%/-25% of actual prices
- at 16 weeks ahead (approximate time between of the year ahead 'final forecast' and the start of the incentive scheme), the ability to use as forward power prices is only +50% / -30%

[18] http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/contracts/

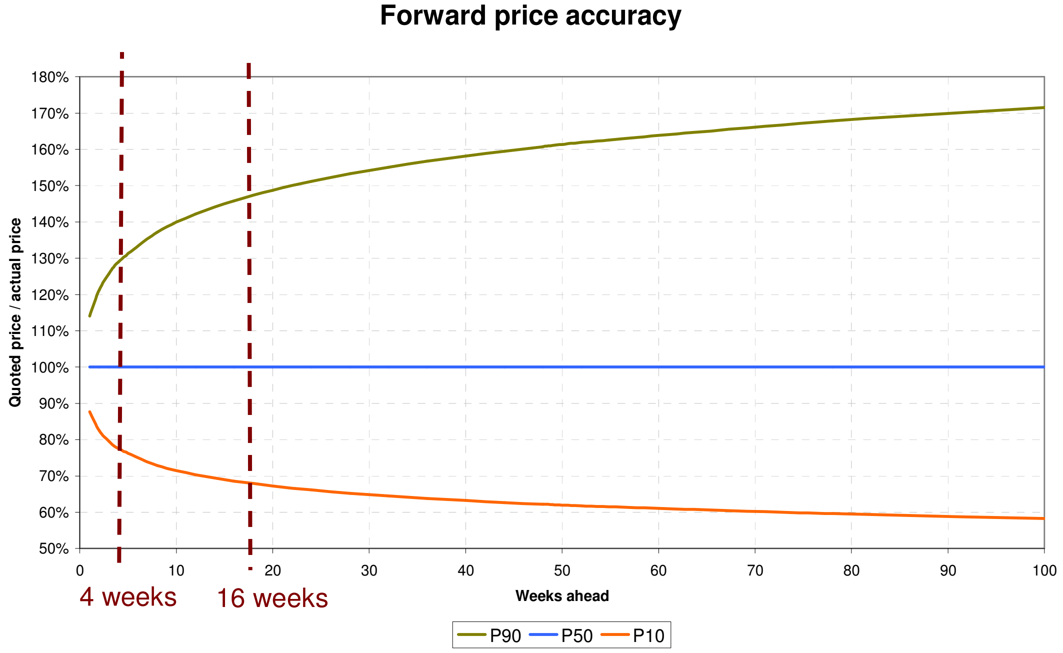

Figure 10: Volatility of power price forecast

134 The actual power price to which National Grid is exposed presents a significant volatility, which impacts the ability of National Grid to forecast balancing costs. Figure 11 illustrates the volatility of half-hourly, mean daily and mean monthly power prices (SPNIRP)[19]

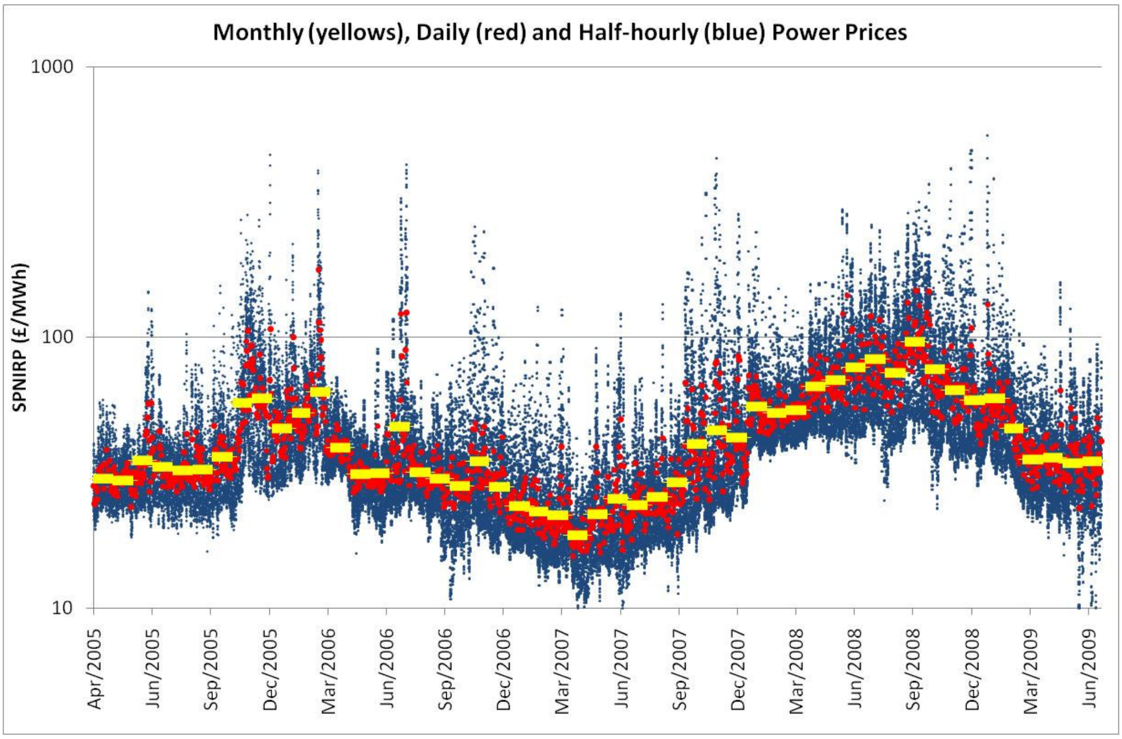

Figure 11: Power price volatility, as represented by SPNIRP

[19] SPNIRP, as defined in NGET transmission licence, is the Single Price Net Imbalance [volume] Reference Price for each settlement period

135 It can be seen that the risk of forecasting power price is directly related to the time between the forecast and real time. This demonstrates the difficulty for National Grid in accurately using forward power price as an indication of short term power prices at the year ahead stage.

2.5.2 Balancing Mechanism (BM) prices

136 Prices in the BM directly impact on the costs of balancing actions taken in the BM and (indirectly) pre Gate closure, driving costs of Energy imbalance, margin and response.

137 The average Bid and Offer prices accepted in the BM depend upon:

- the Bid and Offer prices submitted (which reflects the degree of competition in the BM as well as generators' behaviour); and
- the volume of actions taken to balance the system

138 Figure 12 below shows the ratio between volume weighted average accepted BM Offer and Bid prices and the prevailing electricity market price as defined by SPNIRP. The black lines indicate the typical boundaries of the values.

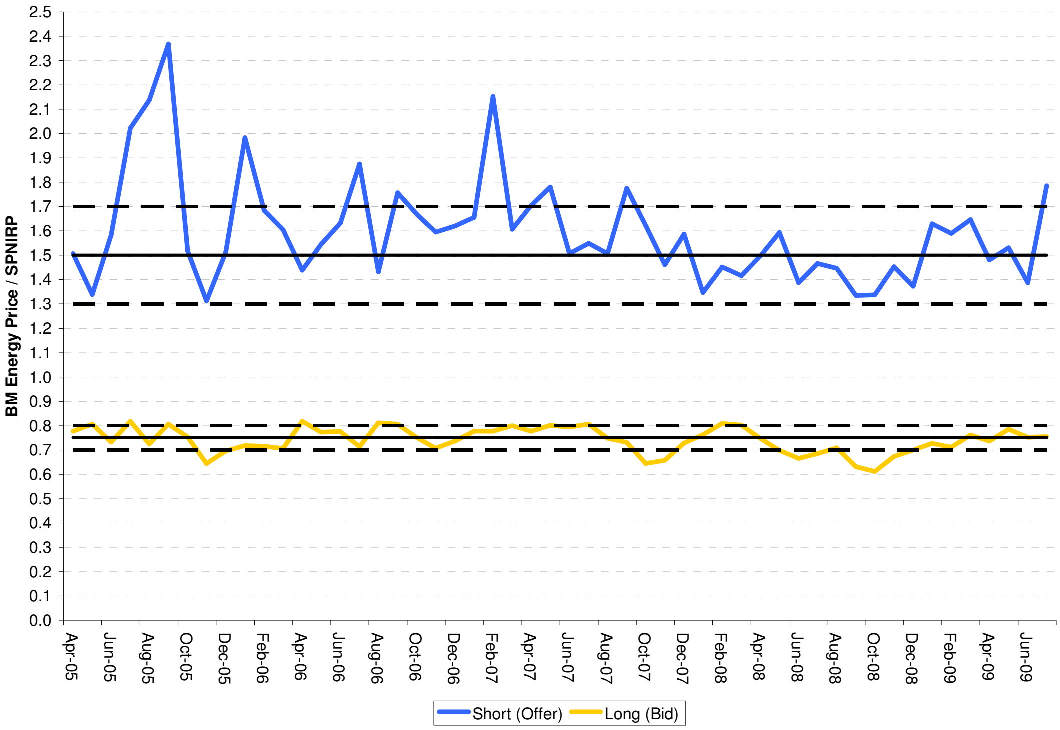

Figure 12: Ratio between BM prices and Power Price

139 As can be seen, there is a strong (and relatively stable) relationship between power prices and BM prices, meaning that any uncertainty and volatility associated with power price (as mentioned previously) will directly reflect in a similar level of uncertainty and volatility in the prices of services procured in the BM.

2.5.3 Balancing Services Contracts

140 Balancing Services (BS) contracts for the provision of Margin (Short Term Operating Reserve (STOR) and BM Start Up contracts), Response (mandatory and commercial response services) and Fast Reserve are assessed against the relevant economics when compared with their alternatives. The volumes available from contracts reduce the volume actions to be taken in BM and hence the costs incurred.

141 National Grid can develop the terms and procurement methods for these balancing service contracts to create efficiencies in the provision of these services and to encourage competition. National Grid constantly reviews market arrangements to ensure a wide range of options are made available for managing the system. National Grid has recently completed a review of the STOR, Fast Reserve and Firm Frequency Response services, specifically making changes to better facilitate longer-term services and demand side provision.

142 Any balancing service contract agreed is dependant on the provider submitting suitable prices and terms and these being assessed as economic compared to the alternatives and accepted by National Grid. Therefore, National Grid has control over the acceptance of contracts and can influence this cost driver. National Grid is subject to changes in the bidding behaviour of submitted prices from service providers. These may be influenced by the level of competition for the services, underlying cost drivers (e.g. maintenance costs), fuel prices and, changes to service terms and conditions.

143 As shown in Appendix B of our Consultation Document 2/09[20], the volume of services procured via Balancing Services contracts vary through the years. As mentioned previously, the volume of contracts depend both on the number of providers, the system requirements and on the relevant economics assessment against available alternatives.

2.5.4 Volume of Wind Generation

144 Increased wind capacity and the corresponding greater generation intermittency places greater balancing costs on both market participants and National Grid. How this burden falls between National Grid and the market depends on the incentives (efficient avoidance of imbalance charges) to do so and the market's ability to forecast wind output and balance its own position.

[20] http://www.nationalgrid.com/NR/rdonlyres/95D86B42-F2A4-4317-83D5-551F9AE27D7E/36514/Energyconsultation_final.pdf

145 While increased renewable generation has benefits in reducing carbon, from a balancing perspective higher densities of wind generation will lead to an increased volatility for forecasts of plant output at all lead times. This increased unpredictability of plant output impacts most of the activities National Grid undertakes to balance the system.

146 All energy related products will be affected as the wind penetration level becomes more significant, but margin costs are likely to be specially affected in the near term. This is due to the fact that, with greater uncertainty of generation output, it will require National Grid to hold greater levels of margin to secure the range of possibilities.

147 The impact on energy imbalance is via a possible effect of wind generation on market length. In our analysis so far we have not yet found a robust statistical link between wind and market length and are continuing to investigate this. The evidence to date is discussed further in section 3.

148 As highlighted in section 2.2.4, the volume of footroom actions required is significantly impacted by the availability and running regimes of generation, in particular inflexible ones such as nuclear and wind, as high levels of inflexible generation, during low demands, often sees flexible generation moving toward their minimum stable output. An increase in the capacity of connected wind would be expected to increase incidence of these situations and hence an increase in the volume of actions, and costs, of creating additional footroom.

149 In addition, the number of flexible units running at their minimum stable output prevents sufficient high frequency response being carried on part-loaded units. This results in an increased volume of Offers to position plant in order to provide high-frequency response and so increases costs here as well.

150 Our current estimate is that each additional 100 MW of wind will have an effect in the energy components of circa £1 million per year. This cost reflects the impacts across margin, footroom and response.

2.5.5 Level of market imbalance (market length)

151 The volume of actions taken by National Grid for Energy Imbalance is a result of the difference between self-despatched generation and demand in a given half-hour. This difference gives rise to the market length which is therefore a direct driver of the costs of this component. Other components are indirectly affected by market length, particularly Margin, as the headroom created when units are pulled back to resolve energy imbalance creates additional headroom which could be utilised if demand subsequently increases or other generation is lost. As such this requires National Grid to take synchronise fewer machines to create this headroom.

152 In long market periods (demand lower than generation), energy imbalance actually reduces the costs of system operation (negative cost), reducing overall BSUoS costs. In any given month, a number of periods will have long markets and a number of periods will have short markets. The net effect over the whole month will define if the mean monthly NIV is short or long. Because costs incurred in periods with short markets are asymmetrical to the incomes received in periods with long markets, as the mean monthly NIV move towards a more balanced position, the income from energy imbalance decreases to the point of becoming a cost. Figure 13 illustrates the relationship between market length, as measured by the Net Imbalance Volume (NIV), and energy imbalance costs based on outturn data since BETTA Go-live.

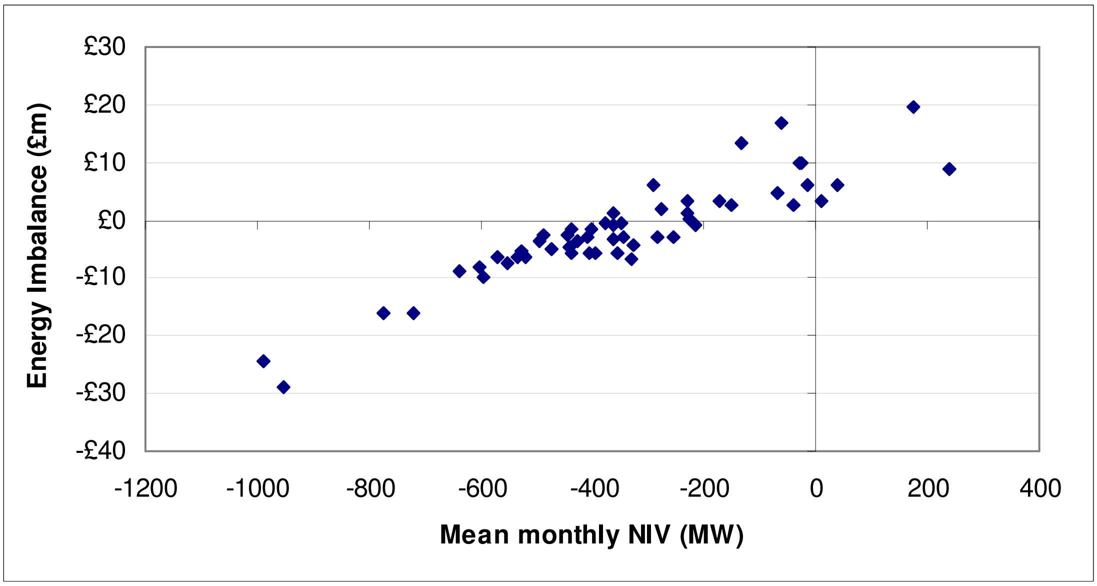

Figure 13: Mean Market Length and Monthly Energy Imbalance Costs

153 Market length is dependent upon the demand expectation from generators and suppliers (and how this differs from the outturn), their respective contracting strategies and the market incentives (efficient avoidance of imbalance charges). National Grid forecast market imbalance levels when setting BSIS cost targets albeit with some uncertainty.

154 The uncertainty in market length forecast can be divided in two areas: the expected mean value and the expected half-hourly volatility.

155 Figure 14 illustrates mean monthly NIV since BETTA Go-live (dark blue line) and a 3-month rolling moving average (light blue line) to smooth the data and facilitate analysis of the behaviour of this driver and demonstrates the uncertainty of forecasting a mean value of market length.

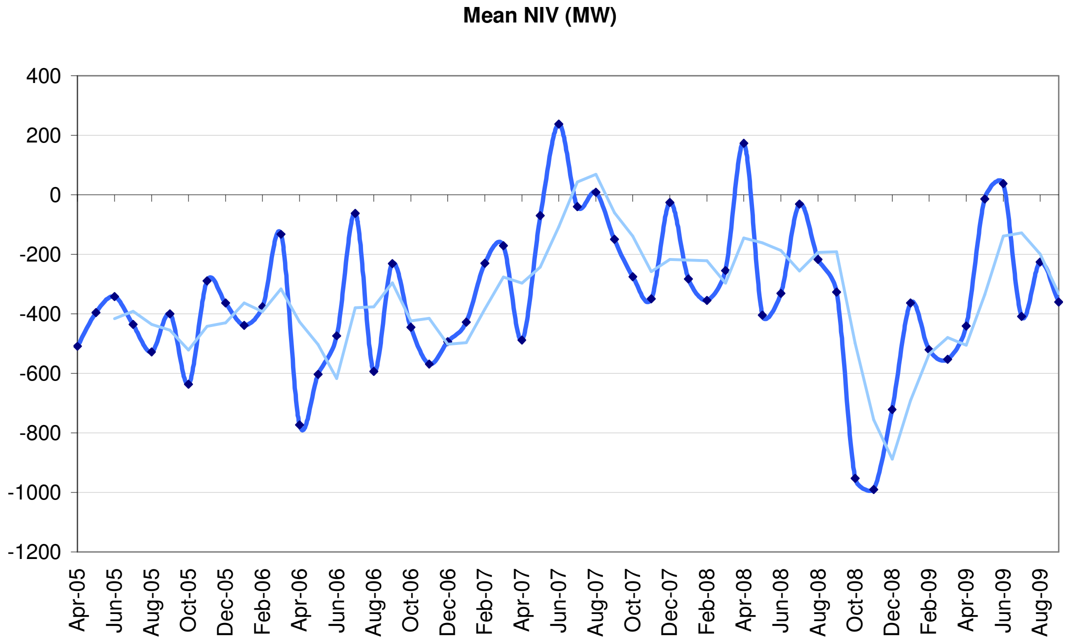

Figure 14: Trajectory of market imbalance

156 Apart from the unpredictable nature of the mean value of market length, the values to which National Grid are actually exposed have a half-hourly granularity with significant volatility, as illustrated in Figure 15.

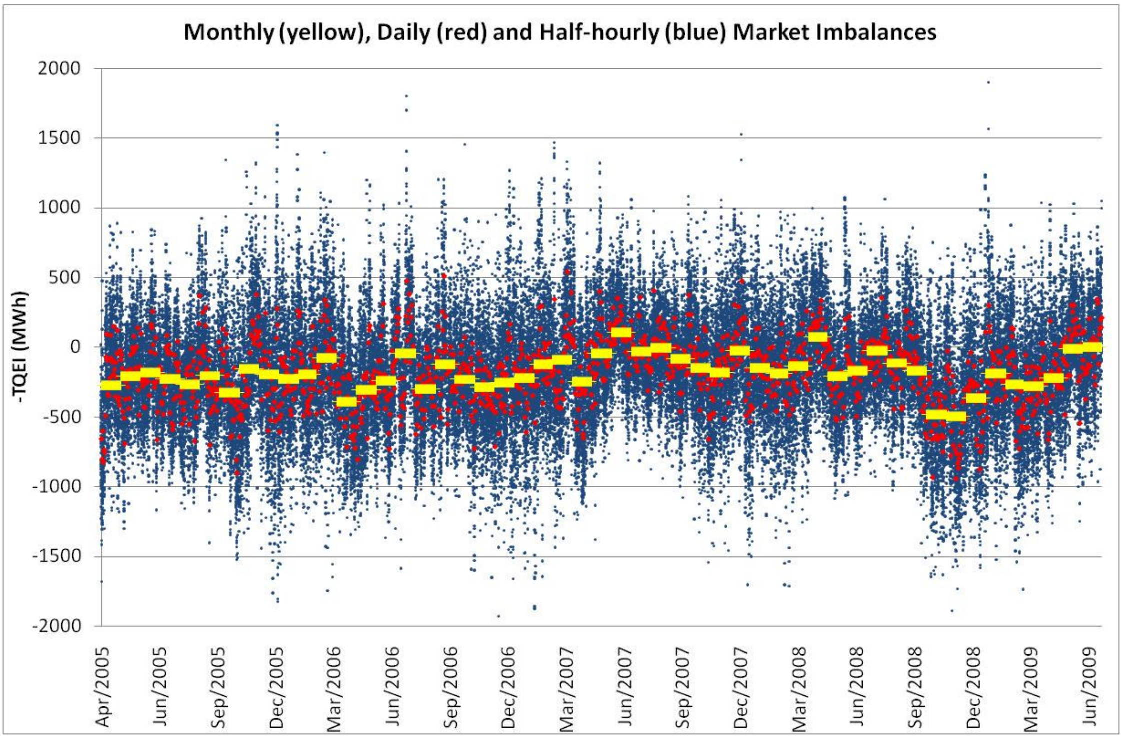

Figure 15: Volatility of market imbalance

2.5.6 Generator availability and operating regimes

157 The availability of certain generators, especially inflexible ones such as Nuclear and Wind, allied to changes in operating regimes as a result of regulatory conditions (such the Large Combustion Plant Directive, LCPD) and the impact of changing fuel prices can and do affect the system conditions.

158 Under the LCPD there is approximately 8.5 GW of opted out[21] coal plant that has significantly changed its operating regime and, in the longer term, those generators along with an additional 3.5 GW of oil plant are due to close by 31st December 2015 (totalling 12 GW of plant closures).

159 Two extreme situations can be described to illustrate the effect of generation availability and changing operating regimes. On one extreme, the combination of low demand periods (such as summer overnight), high inflexible (nuclear and wind) generation and the self-positioning of flexible generation at minimum levels rather than desynchronising[22] causes a situation whereby there is insufficient flexibility to reduce generation to meet negative reserve requirements and therefore balance the system. As a result National Grid is required to de-synchronise units to create additional footroom at a high cost (due to the high differential between the bid price to de-synchronise a unit and the offer price to increase generation from minimum output levels).

160 Conversely, low inflexible (nuclear and wind) generation and limited running of generation subject to LCPD rules has historically seen a reduction in the amount of margin inherent on the system. This is due to LCPD rules placing a strong incentive to run all generation units together and as a result generators needing to choose between running all generation or no generation (i.e. very ‘lumpy’ generation decisions, with the decision often being not to run). As a result of this reduction in market provided margin, the volume of actions taken by National Grid to procure operating reserve increases.

2.5.7 Requirements for services to comply with NETSSQSS

161 The volume procured for certain services depend on the requirements of the National Electricity Transmission System Security and Quality of Supply Standards[23] (NETSSQSS). For instance, the largest infeed loss in the system (both in the generation and in the demand side) dictates the amount of frequency response required to secure the system and so

[21] Under LCPD, coal and oil plants had two basic options:

- Fit Flue Gas Desulphurisation (FGD), thus being allowed to run as usual (“opt in”); or
- Continue to run with a limited life derogation, with 20,000 hours of operation between 1st January 2008 and 31st December 2015 (“opt out”)

[22] Possibly due to wear and tear on plant and the increased risk of start up failures the next morning

[23] http://www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode/

the number of units that are despatched to provide this service. In the longer-term the largest infeed loss is likely to increase as larger generating units connect to the system. Requirements may change due to the output of the SQSS review and the investigations into the abnormal generation losses of May 27th 2008[24].

162 Additionally, National Grid sets Short Term Operating Reserve Requirements (STORR) according to a statistical analysis that seeks to ensure that the risk of not having sufficient generation to meet demand is lower than 1 in 365. These requirements are set depending on the level of demand forecast error, plant loss frequency, wind forecast error, etc.

163 Therefore, whilst the volume of certain services are dependant upon the requirements set in industry codes in order to ensure desired system security levels, some proportion can be controlled by National Grid through the continuous assessment of system conditions and optimisation of internal processes.

2.5.8 Retail Price Index (RPI) – impact on costs of reactive power

164 Like Power Prices, RPI is forecast at the year ahead stage and is another factor not within the control of National Grid. RPI is based on the projections by Experian Business Strategy. As discussed in section 2.3.1, prices for reactive provision under the default arrangements are dependant upon RPI.

2.5.9 Level of active power flows across the transmission system

165 Volumes of reactive power required to secure the system are partly dependant on the level of active power flows across the system. The higher the level of active power flows, the higher the reactive power absorbed by the transmission system and so higher volumes of reactive power are required to compensate for this increase.

166 Figure 16 shows the reactive power produced or absorbed by an overhead line. As can be seen, the volume of reactive power absorbed (increasing the reactive requirements) increases as active power flows across the line increase. Therefore, as active power flows across the system increase, the level of reactive power absorbed also increases.

[24] http://www.nationalgrid.com/NR/rdonlyres/E19B4740-C056-4795-A567-91725ECF799B/32165/PublicFrequencyDeviationReport.pdf

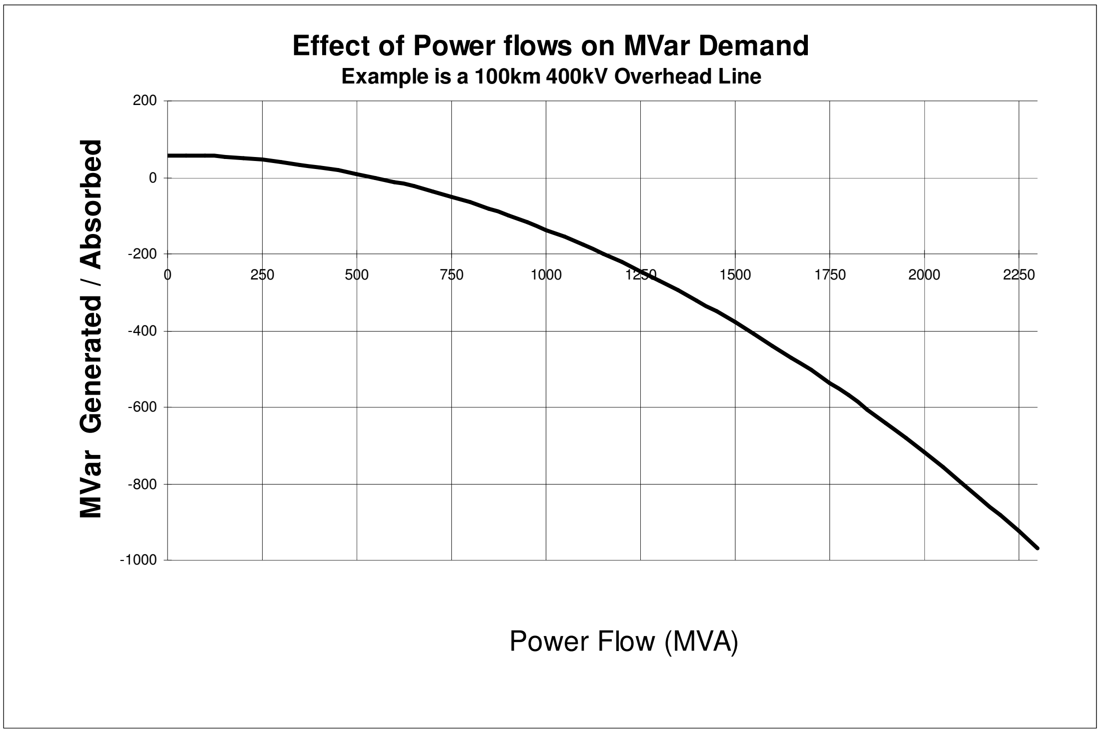

Figure 16: Impact of Power Flows on Reactive Power

167 The volume of active power flows on the system is determined by the disposition of generation and demand. The level of active power flows across the transmission system can to some extent be forecast and so the level of reactive power absorbed or produced by the system can also be forecast. However, changes in generation profiles in line with changes in market dynamics can occur outside our forecast, resulting in a change in reactive power levels.

2.5.10 Consumer Reactive Power Demand

168 Consumer reactive power demand follows similar trends to demand for active power and, therefore, can be forecast reasonably accurately. There are a number of factors that can impact on reactive power demand levels. The main factors are generally weather related, such as an abnormal hot spell in the summer leading to an increase in air conditioning load and so an increase in reactive demand.

2.5.11 Commercial Reactive Power contracts

169 Commercial contracts for the procurement of reactive power are assessed against the relevant economics when compared with the default mechanism. The contract is dependant on the provider submitting a tender and this being accepted by National Grid. Therefore, National Grid is in control over the acceptance of contracts and can influence this reactive cost driver to a limited extent, i.e. if the provider has not retracted the tender on the back of increasing default prices.

170 The use of Reactive Power contracts can provide a hedge against increases in default prices (driven by wholesale power prices and RPI) and increases in volume (driven by weather and active power flows) as it offers a mechanism to pay capability (i.e. fixed) payments in return for lower utilisation (i.e. variable) payments

171 The volume of reactive power procured via market arrangements has decreased over the last four years. National Grid aims to review the market arrangements currently in place and has recently submitted a CUSC Amendment Proposal (CAP173)[25] to improve the timescales for reactive market tender acceptance.

2.5.12 Reactive power dispatch

172 To control local voltage levels and optimise voltage profile across the system, National Grid uses both generators and transmission equipment. Reactive power requirements are generally localised and, as such, there may be a limited number of providers that can deliver the service in a specified area.

173 National Grid uses a number of tools and procedures to determine the most economic method of dispatching reactive power. This results in both transmission equipment and generators being used to manage voltage to deliver an economic solution.

174 The dispatch is determined by both pre- and post-contingency (i.e. considering credible circuit faults) considerations, location of generation and transmission equipment and cost of provision.

175 National Grid has control over the dispatch of reactive power across the system. By optimising the voltage profile and managing the output from generation, volumes of reactive power can be controlled.

2.6 Black Start cost drivers

176 Black Start costs are based on the contracts agreed with counterparties, which are exclusively generation owners at present. The contract costs comprise an availability fee for the ongoing provision of the service, any capital costs required to secure the service and any costs incurred in testing service providers across the year.

25 http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/amendments/currentamendmentproposals/

177 For the purposes of Black Start, the network is considered as a number of interconnected zones. Within each zone, we contract to make certain that, under black start conditions, there is at least one station available and ready to connect to a 'dead' bar to begin system and demand restoration. To ensure this confidence, we endeavour to contract with more than one station in each zone.

178 The equipment required at a power station to provide a Black Start service tends to be installed at the time the station is built. Retrofitting this equipment can be done but is often difficult and expensive. Hence, it would be expensive and asset intensive to create a 'competitive' market for the provision of Black Start

179 Any increase in prices or requests for contribution to the capital costs to install new or replace/refurbish existing assets is assessed and, where necessary, the Generator is asked to provide supporting evidence.

Question 1: Have all cost drivers for Energy, Reactive, Black Start and Transmission Losses been captured and correctly identified as being within or outside National Grid control?

2.7 Overview of Constraints

180 Constraints occur when there is a deficit in system capacity to either meet local demand or transport energy to other parts of the network. This occurs where the difference between generation and demand within an area or zone exceeds the capacity of the transmission system connecting that zone to the rest of the system. e.g. Abs(Zonal generation – Zonal Demand) > system capacity. A more detailed explanation can be found in section 2.3 of our Consultation Document 3/09[26].

181 As shown in Figure 17 below, the volume of constraint is dependant on the generation in excess of demand, or vice versa, behind a system boundary relative to the transmission capacity of that boundary. As generation and demand vary, the volume of constraint required will also change.

[26] http://www.nationalgrid.com/NR/rdonlyres/5BCE1A3B-D7BC-4F1B-8DFF-68B6162643DA/36862/NGETSystemOperatorIncentivesfor1April2010Consultat.pdf

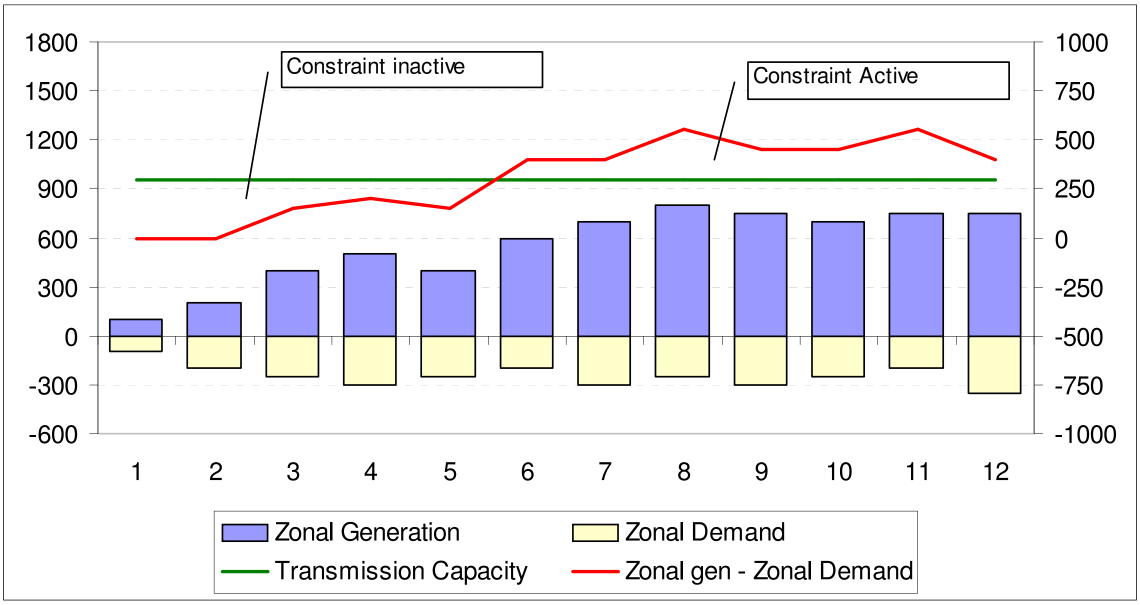

Figure 17: Volume of Constraints

182 The green line indicates the system boundary capability when considering a single boundary. This can be an intact system capability, i.e. all equipment in service, or with circuits out of service. When the excess generation (i.e. generation – demand) exceeds the boundary capability, shown by the red line, the constraint is considered ‘active’ and action is required to ensure that the boundary capability is not exceeded.

183 Alternative actions taken to manage constraints incur different costs. As shown in Figure 2, constraint costs are forecast to make up approximately 22% of BSUoS costs this year.

184 The preferable outcome when it comes to managing the costs of constraints is to prevent the constraint from occurring in the first place. Significant efforts are made to avoid constraints, for example requesting the relevant TO to reschedule outage(s) to align them with a generator outage, utilisation of enhanced ratings, reconfiguration of the transmission system, etc. However, further action is often required to manage a constraint.

185 Where a constraint must be managed by limiting or increasing the output of a generator, costs will be incurred. In some circumstances other services, such as system-to-generator intertripping arrangements, can be utilised assuming the necessary generator and transmission infrastructure and appropriate agreements are in place. Use of an operational intertripping scheme will incur a tripping fee, if the scheme operates, governed by the CUSC; whereas use of a commercial intertripping scheme is likely to involve payment of an arming fee as well as a tripping fee if the scheme operates; both of which will increase the overall cost of constraints.

186 Management of transmission system constraints is achieved by the most economic method available as set out in the Balancing Principles Statement. This includes changing the output of generation using the BM, forward trading or bi-lateral contracts that limit generation output.

187 Figure 18 shows the breakdown of constraint costs between actions taken in the BM and trades, intertrips and contracts.

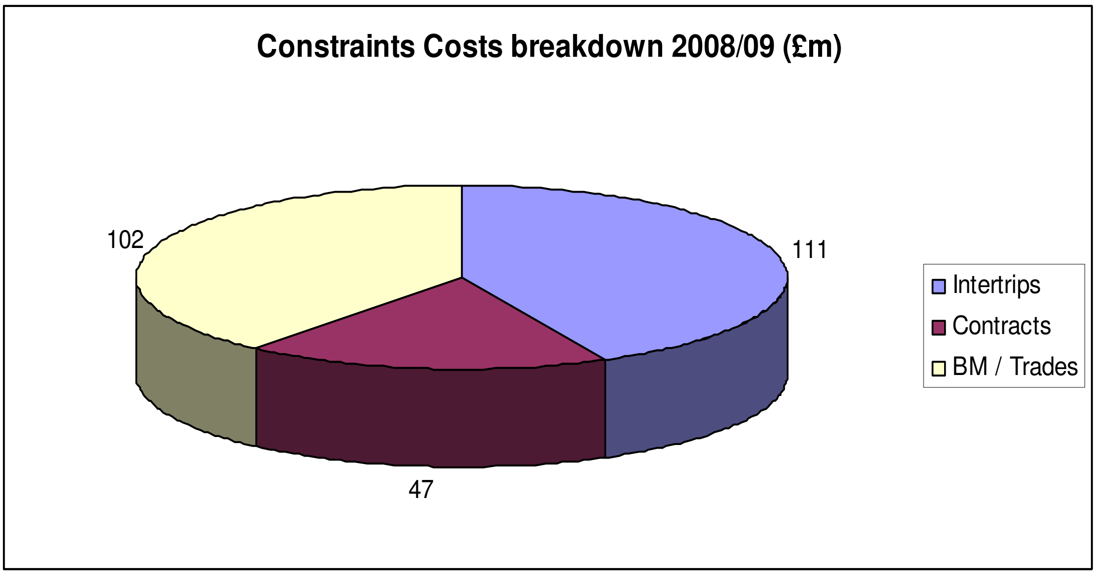

Figure 18: Constraint Costs by resolving action 2008/9

2.8 Constraint Cost Components

188 Constraint costs have the following component factors

- The volume of actions required
- The price of those actions

2.8.1 Volume of Actions

189 The volume of actions required to manage a constraint is dependent on:

- Generation pattern within the constrained zone.
- Wind Generation
- Demand Levels
- The volume and direction of flows on interconnectors
- Transmission System Capacity
- Transmission system faults
- System-to-generator intertripping arrangements

2.8.1.1 Generation pattern

190 The generation pattern can significantly impact on constraint volumes and therefore costs. As shown previously, for a static demand and system capacity, the volume of generation has a significant impact on the constrained volume:

Abs(Zonal generaton – Zonal demand) > system capacity

191 The output of generation in excess of the constraint limit behind the constraint boundary must be reduced to secure the system

192 The generation pattern is determined by market conditions with approximately 97% of the volume being self-dispatched. The remaining 3% of volume is managed by National Grid through the BM.

193 Whenever possible, National Grid endeavours to reduce the likelihood of constraints occurring by aligning the transmission outages with the generators intended outage plans as indicated by their submitted information under the Grid Code – section OC2. However, there is always a risk that the generation outage may move, resulting in the potential for constraint costs to be realised.

194 Whilst National Grid presently has limited influence over the initial dispatch of generation, National Grid can control the volume of generation once dispatched. The two main methods of managing constraint volumes is to take actions in the BM to reduce output (or increase for import constraints) or to implement bilateral contracts that can alter generation patterns.

195 The implementation of Locational BSUoS[27] or an alternative form of targeted pricing may influence generator dispatch decisions and improve the co-ordination of generation and transmission outages, therefore serving to reduce constraint costs.

2.8.1.2 Wind Generation

196 A significant proportion of the new wind farms are located in Scotland, behind the Cheviot boundary. This boundary is not compliant with the standards set out in the NETSSQSS and, as such, additional generation will increase constraints costs unless there is a reduction in other forms of generation output from the same group.

197 The impact of wind capacity, as moderated by load factor, on the constraint volume is non-linear and, currently, each additional 100 MW of new wind connecting behind the Cheviot boundary is expected to increase constraint costs by £1 million per month.

198 The above costs are not necessarily caused by the intermittent nature of the wind generation, but mostly due to the non-compliant boundary. As such, an additional 100 MW of conventional generation behind Cheviot would have similar impacts[28].

[27] http://www.nationalgrid.com/uk/Electricity/Charges/modifications/uscmc/

[28] Conventional generation could respond better to market price signals with lower output during low demand periods. However, the expected load factor of a conventional plant is much higher than that of wind generation, thus both effects are likely to cancel each other.

2.8.1.3 Demand levels

199 Demand is led by the requirements of consumers. National Grid forecasts the level of demand and uses this forecast to calculate the expected constraint volumes. National Grid can forecast demand to a reasonably level of accuracy.

200 The volume of constraints is influence by the level of demand as shown in Figure 17. However, there is presently limited scope to use demand as a method to manage constraints although efforts have been made in recent years to encourage demand side participation in the BM and other services.

201 For export constraints, demand would need to be increased within the constrained zone to alleviate the constraint. Users may not be able to increase their energy usage at the time required, therefore, this is generally not an option that is currently available.

202 For import constraints, demand would need to be reduced within the constrained zone to manage the constraint. It may be possible to reduce energy output from demand centres with a large enough capacity, such as large energy users like cement works or large industrial sites some of which have commercial contracts in place for other Balancing Services.

2.8.1.4 Direction and volume of flows on interconnectors

203 There is currently one interconnector between the GB transmission system and mainland Europe, the England – France Interconnector, Interconnexion France – Angleterre (IFA). This interconnector connects the GB transmission system at Sellindge to France. The energy flowing on the IFA is traded and as such dependant on the price spread between power price in France and in the UK. When importing power, it acts as large generator and when exporting acts as demand. The position of large units of generation or demand at an extreme point on the system has the effect of materially changing the flows on the system. The volume and direction of flows has a significant effect on volumes of constraint in the South of the transmission system.

204 A second interconnector between the UK and the Netherlands, known as BritNed, is under construction and due to commission in early 2011.

205 The Moyle Interconnector connects the GB transmission system in Scotland to Northern Ireland. The direction of flow of power on this interconnector affects constraints on the Cheviot boundary. When there is a limit to the power transfer which can be secured from Scotland to England, exports on the interconnector reduce the natural flow across the Cheviot boundary.

2.8.1.5 Transmission System Capacity

206 The transmission system is generally constructed such that there is sufficient capacity for all the connected generation to reach the wider market. This meets the standards set by the NETSSQSS.

207 However, there are a number of intact system restrictions i.e. boundaries on which constraints can occur with all circuits in service. Such constraints arise from a lack of transmission capacity relative to the connected, and running, generation and demand. The Cheviot boundary is one with such a restriction.

208 The main reason for system capacity restrictions is associated with outages of transmission system equipment required for:

- New demand or generation connection
- System reinforcement
- Asset replacement
- Maintenance
- Repairs
- Fault outages

209 System capacity reductions caused by outages can result in the restriction of power flows across the remaining system. The main mitigation methods used to minimise potential constraint volumes at the planning stage are:

- nesting of multiple outages – thus maximising system access while limiting exposure to the constraint
- careful placement of the outage to correspond with favourable generation or demand conditions
- developing arrangements that limit the impact of the outage, such as reducing outage length by changing working patterns.

210 Within Scotland, National Grid as the System Operator coordinates the development of transmission circuit outage plans in collaboration with Scottish Transmission Owners (STOs). The rolling outage planning process, including timescales for exchange of outage data, is outlined in the SO-TO Code (STC)[29] for STOs and in the Grid Code[30] for generators. The process is iterative in nature, culminating in an agreed Final Outage Plan for the next financial year by calendar week 49 in the current year.

211 There are arrangements in place through the STC to allow National Grid to request changes to the final outage plan as system circumstances change in order to ensure continued delivery of standards set by the NETSSQSS and where changes may help to reduce constraint costs.

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[29] Procedure STCP11
[30] Operating Code no. 2

212 Any changes to the final outage plan requested by National Grid[31] allow the STOs to recover reasonably incurred costs from National Grid. A nominal allowance of £1m[32] is currently available to National Grid (upon which it is incentivised) to make outage change payments to the STOs. These payments are to provide compensation to the STOs for increased opex costs that the STO may be exposed to as a result of the SO's request. National Grid recovers these payments via the Balancing Services Use of System charges. The scope for cost recovery is limited to changes requested by National Grid to the final outage plan.

213 In England and Wales (E&W), internal 'transmission procedures' are in place for exchange of outage data within National Grid and to manage outage changes. These procedures are similar to the outage planning procedures in the STC. There is no outage change allowance for recovery of reasonably incurred outage change costs for the E&W TO.

214 National Grid liaises with the STOs, in accordance with the obligations laid down in the STC to identify capital schemes that either reduce constraint costs or mitigate the risk of constraints occurring (known as SO led TO capex). National Grid in its role as Transmission Owner (TO) in E&W and SO takes advantage of this combined role by continual economic assessment of such schemes. The lead-time for such schemes makes this a mechanism for reducing constraint costs in the longer-term.

215 As discussed in the introduction to this consultation, National Grid published an informal consultation in September on a range of proposals that explore potential improvements to the management of System Capacity[33].

2.8.1.6 Transmission System Faults

216 Reduction in system capacity due to transmission system faults can not be mitigated against in the same way as for planned outages by National Grid. By their nature, the occurrence and impact of fault outages cannot be forecast accurately due to the number of assumptions that need to be made about what conditions may exist at the time of the fault.

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[31] The definition of an 'outage change' is given in NGET's Transmission Licence, Special Condition AA5A, Part 2(ii), paragraph 21A.

[32] NGET's Transmission Licence, Special Condition AA5A, Part 2(ii), paragraph 15C put in place an allowance for outage changes (ON_t) of £1,000,000 in 2004/05 prices. The formula in paragraph 15C allows an adjustment to the term ONt using the $IRPI_t$ index which is defined in paragraph 15A.

[33] http://www.nationalgrid.com/NR/rdonlyres/FB4A9925-15AB-462A-B516-33543A44B460/37082/PotentialEnhancedElectricityTransmissionOwnerIncen.pdf

217 Faults resulting in damage to transmission system equipment require significant outages to allow safe return of the equipment to service. As the outage has not be subject to the normal planning process, the outage required can be lengthy as resource, equipment and access may not be available. It will not have been placed against favourable generation conditions, leading to an increased risk of actions being taken to secure the system.

2.8.1.7 System-to-generator intertripping arrangements

218 System to Generator tripping services may be utilised to reduce the volume of generation that has to be constrained prior to a fault occurring[34]. The immediate change in generation output in the event of a fault permits increased boundary transfers over and above those possible when generator run down rates must be used to manage a post-fault situation. Use of System to Generator tripping is dependant on the required infrastructure, and commercial or operational agreements, being in place and agreement from the relevant generator that they are willing to have such facilities.

219 Use of System to Generator tripping services avoids the need for replacement energy and margin prior to the fault occurring as well as dissipating the requirement for the initial BM actions to control transfers out of the area. For commercial intertrips there is normally an “arming fee” associated with activation of the intertrip, along with a “tripping fee” should the intertrip operate to disconnect the unit. National Grid raised a CUSC amendment proposal (CAP170) on 27 February 2009 seeking to reduce potential constraint costs by limiting the costs associated with certain commercial intertripping schemes.

220 The costs of utilising an intertrip are assessed against the alternative methods by which the constraint could be managed, e.g. managing in the BM. Where use of the intertrip is economic against the other options that are available then it will be utilised.

2.8.2 Price of actions required

221 The cost of resolving a constraint within the BM is influenced by the actions taken to alleviate the constraint, actions required to rebalance energy and any actions required to preserve system margin.

222 Where economic to do so, and where the facilities exist, trades, intertrips and / or bi-lateral contracts may be used to manage constraints.

[34] Normal management of constraints requires that generation prior to a fault occurring is at a level where, should a fault occur, it would not cause unacceptable thermal or voltage excursions.

223 The price of actions taken to manage a constraint is dictated by the available generation. For constraint boundaries where there are limited levels of generation that can be controlled this will force National Grid to take the most economic option that is available as dictated by the economics of the local generation. For constraint boundaries with a larger pool of generation the price is generally close to the price of marginal generation.

224 To help provide some price certainty, and to manage the constraint price risk, National Grid has recently developed new contract forms such as the Constraint Management Service[35] to better manage constraint costs and to improve transparency. At present, the opportunities to contract in advance are limited due to the uncertainties over generation background and transmission outage planning (i.e. outages may start late or be cancelled). In response, National Grid are reviewing the risk balance in constraint contracts which may allow the ability to contract further in advance, for example through wholesale price indexation.

225 The use of intertrips can significantly influence constraint costs, as detailed in Section 2.8.1.7 above

2.8.2.1 Alleviation and Energy Rebalance

226 The price of actions taken to manage constraints, and any replacement actions, are set by market participants and, as such, the main driving factor is the prices available from generation to manage the constraint in the BM and/or the National Grid's ability to negotiate favourable rates outside of the BM. These rates have historically moved with wholesale power prices thus reflecting market conditions and placing a limitation on the level of price control that can be achieved.

227 In general, it would be expected that both Bids and Offers will move with underlying wholesale prices. However as wholesale prices increased in the summer of 2008 Bid prices levelled off whilst Offers continued to rise. This led to an increase in the "spread" between Bid and Offer prices for constraint resolution as shown in Figure 19. This factor contributed to increased costs relative to those forecast for constraints when setting the BSIS target for 2008/9. This increased "spread" was seen in the utilisation of trades and contracts to manage constraints. However, the use of intertrips, where available, did help to cap some of this upward trend.

35 http://www.nationalgrid.com/uk/Electricity/Balancing/services/systemsecurity/constraint_agree/

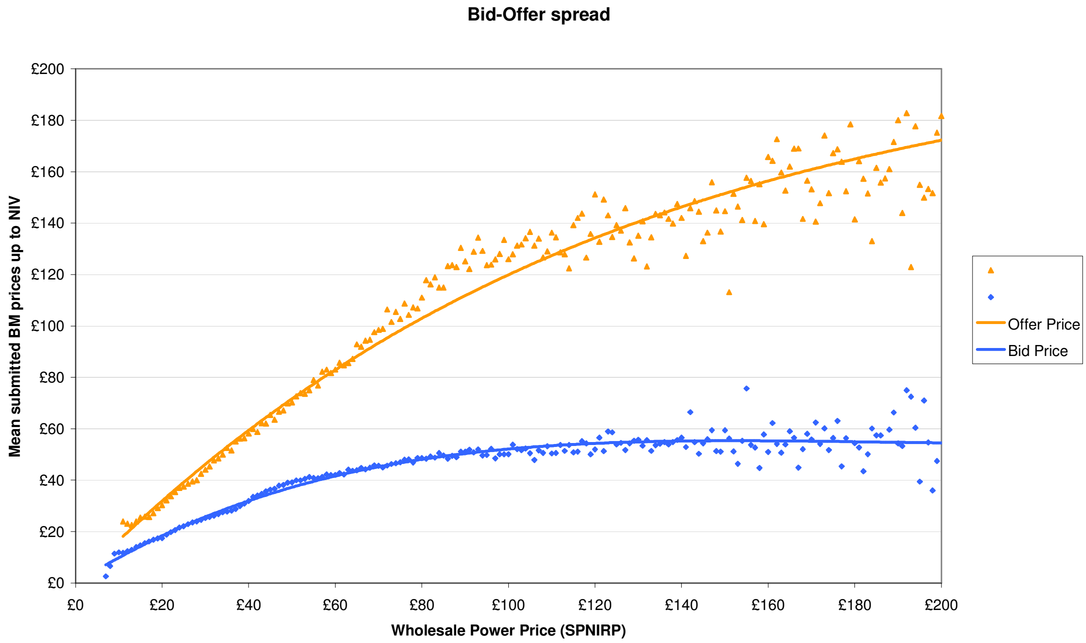

Figure 19: Bid – Offer spread

2.8.2.2 Replacement margin costs

228 The costs of replacement margin actions are a function of prevailing system conditions, the level of generation self-despatched by the market and the disposition of such generation. Replacement margin actions have to be taken from units at unconstrained parts of the system, reducing the pool of available providers and, whereas the margin sterilised by a constraint can be recovered at the most economical rate available, prevailing market conditions will dictate the price paid for this service.

2.9 Future Drivers of Constraints

2.9.1 Transmission Access and Interim Connect and Manage

229 Ofgem and the Department for Business, Enterprise and Regulatory Reform (now the Department for Energy and Climate Change (DECC)) established the Transmission Access Review (TAR) in August 2007 following publication of the Energy White Paper. The review considered the current arrangements for accessing the Transmission system from a technical, commercial and regulatory perspective. The review set out a number of high level principles upon which enduring access arrangements should be based[36].

[36] The principles are set out in the TAR Final Report http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=84&refer=Networks/Trans/ElecTransPolicy/tar

230 Potential reforms to the transmission access arrangements were progressed by industry through normal code and charging governance routes. On 25th June 2009 the Gas and Electricity Markets Authority recommended to the Secretary of State that he use his powers under the Energy Act 2008 to facilitate reform of transmission access as, in its view, the industry had not delivered appropriate reform proposals. DECC has recently issue a consultation on transmission access reforms[37].

231 In May Ofgem issued an open letter setting out its decision on the interim approach – interim Connect and Manage (ICM) – it would adopt to GB SQSS derogations to facilitate the earlier connection of generation to the transmission and distribution systems in GB. ICM is designed to accommodate the advancement of all generation connections.

232 Under the ICM regime, the works that play a part in determining the connection date are only those which are deemed local. The wider transmission reinforcement works required to make a fully compliant connection for all circumstances is no longer required to allow us to make a connection offer, but the non-compliant connection is subject to approval of a derogation against the NETSSQSS by Ofgem. National Grid will raise a request for derogation when offers for a coherent projects have been signed by customers.

233 In practice this means that new generation may be connected prior to the transmission system reaching the standards set by the NETSSQSS, giving rise to boundaries which are derogated from compliance with the NETSSQSS. Derogation for the Cheviot boundary has been in place since the introduction of BETTA. As a result of ICM, it is expected that additional non-compliant boundaries will appear across the National transmission system.

234 Since the implementation of ICM, National Grid has contacted all those customers that had expressed an interest through the quarterly reports to advance their connection. This totals around 5GW of new generation. In Scotland revised offers have been made to 450MW of generation with a further 900MW currently being processed. For England and Wales, approximately 1.6GW has submitted modification applications to advance their connection dates. This increase in non conventional generation presents a new set of challenges in the management of the transmission system as well as increasing the volume of actions required to resolve existing system constraints, in particular existing intact system constraints (e.g. all transmission equipment in service).

[37] http://www.decc.gov.uk/en/content/cms/consultations/improving_grid/improving_grid.aspx

235 Constraint volumes are driven by the difference in zonal generation and demand relative to the transmission capacity. Under ICM, the rate at which new generation connects will increase without wider increases in transmission capacity, which is likely to lead to increased volumes of constraint actions and associated costs.

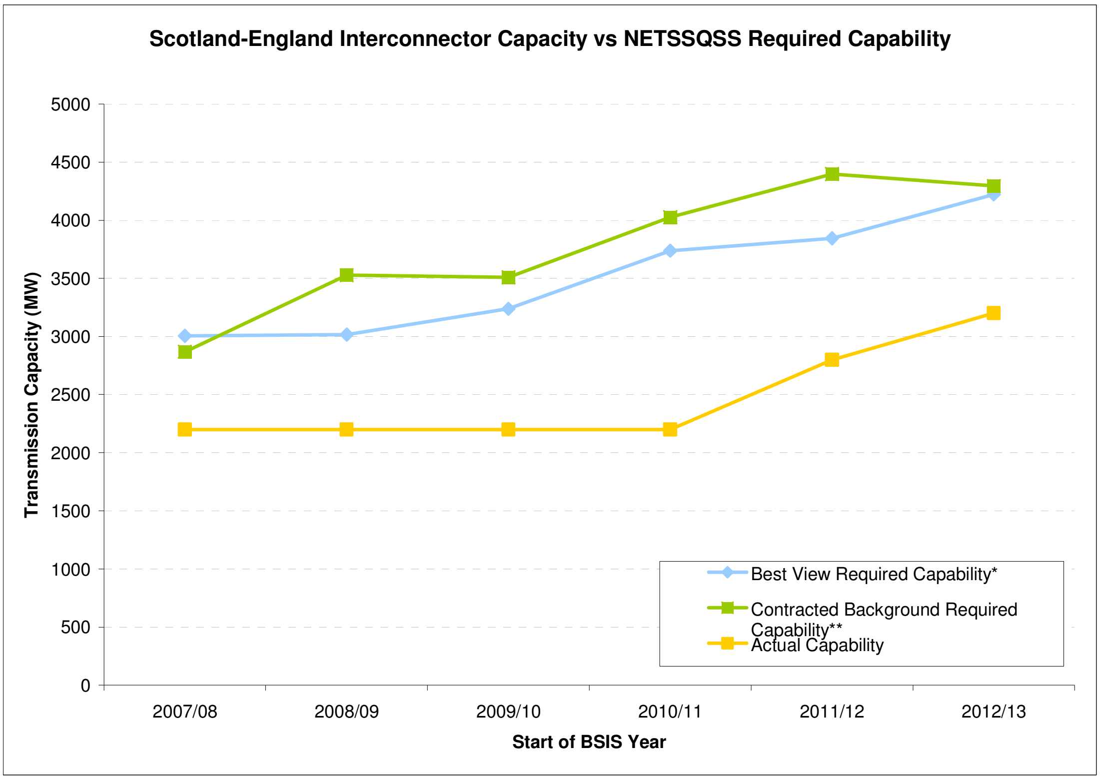

Figure 20: Cheviot Interconnector Capacity Vs NETSSQSS Required Capability

236 Figure 20 shows the planned increase in capacity of the Cheviot boundary (orange line) against the expected generation pattern (blue & green lines). As can be seen, the actual capacity is some way below the required capacity. In 2010/11, this is expected to be near 1000MW, although an increase to the capacity is expected on the boundary around November 2009, note the chart shows capacity at the start of financial (BSIS) year. As the deficit in capacity increases due to new generation connections, the volume of constraint actions will increase, leading to increased constraint costs.

2.9.2 Wind Generation

237 Table 1 shows the total connected generation capacity in Scotland, with a connection agreement with National Grid at July 2009, broken down by generator type. Wind generation is expected to increase significantly over the next few years. This increase in wind is represented above in the expected generation shown in Figure 20.

Plant Type	MW
Wind	1414
Gas	1819
Coal	3386
Nuclear	2289
Hydro	1900
Other	262
Total	11070

Table 1: Connected generation capacity in Scotland

238 Due to ROC[38] payments, moving wind from its maximum output at any time has a high cost relative to conventional generation. To date wind has not been used to manage constraints as conventional generation has provided a more economic alternative. However, we are increasingly likely to be required to constrain wind, particularly during periods of low demand with limited conventional plant running.

239 Amongst these challenges presented by the increased volumes of connected wind is the availability of mechanisms to control the output of all wind generators. National Grid has presented on these issues at a number of Operational Forum and have recently produced a note which has been passed to a number of parties, including AEP and BWEA members[39].

240 There is a significant volume of wind generation which is not part of the BM. To manage the output of such generation, a new balancing service has been developed, known as the 'Generation Curtailment Service'. It is designed for the provision of reduction in output specifically from sites that do not participate in the BM. This service provides National Grid with the ability to curtail a volume of generation with varying response and utilisation time. A number of providers who own or manage sites have been approached to discuss and develop service provision.

Question 2: Have all the cost drivers for Constraints been captured and correctly identified as being within or outside National Grid control?

[38] Renewable Obligation Certificate - (ROC)
http://www.ofgem.gov.uk/Sustainability/Environment/RenewablObl/Pages/RenewablObl.aspx

[39] http://www.nationalgrid.com/NR/rdonlyres/FF277D5B-1D45-460E-A455-E7AE5A2A7C9C/38171/Newsletter_Accessing_Renewable_Energy_Sept09.pdf

Section 3
Forecast

This section looks at the method by which our forecast is constructed and the assumptions made therein. The outcome from this is presented along with the ranges of costs anticipated for the various components for the costs of Balancing Services from April 2010.

3.1 Introduction

241 In this section we outline the main cost drivers on balancing services for 2010/2011 and aim to assess the impact they have on the forecast. In the later part of this section we outline the forecast of the second year of a possible two-year scheme.

242 The methodology used in developing this initial forecast is similar to that used to develop the forecast for the 2009/2010 incentive, with significant improvements by use of a consolidated model in the forecast of the energy related components and additional models used to prepare constraints forecasts.

243 An addition to the Scottish constraint costs model has also been developed. This addition explores the scenario of high wind generation at times of low demand with limited fossil fuel plant running. This scenario arises as increased levels of wind generation displace conventional generation as discussed in section 2.9.2.

244 The outage plan within England & Wales suggests an increased volume of constraints in England and Wales. As a result, separate models have been developed to thoroughly examine those outages which result in the most significant volumes of constraint and thus associated costs.

245 The forecast contains a set of assumptions that try to emulate the main external factors affecting the balancing services costs. The forecast tools are used to produce cost expectations of the various components, while reflecting the relationships between the different areas. A number of simplifications have been made to ensure that the forecast models used are not overly complex whilst maintaining an appropriate accuracy of forecast. Therefore, not all the identified drivers in the previous section are explicitly modelled or represented in the forecasting methodology due to the increased complexity without significant improvement to the accuracy of the forecast.

246 Within the model, a number of assumptions can be called "structural" (hard assumptions), meaning they are not expected to change in the short to medium term. Examples of these are items such as the function relating the frequency response requirement to the demand and the

largest infeed loss to the system. Another example is the relationship between monthly wholesale power prices and the half-hourly indicative wholesale prices (SPNIRP). These structural assumptions are therefore beyond the scope of this initial proposal.

247 The next sections describe the "soft assumptions", those that are subject to variations in the short to medium term.

248 As developed for the BSIS forecast last year, we have used ranges of assumptions to develop our forecast to provide an indication of the likely spread of both BSIS and BSUoS costs.

249 This section is divided in three main parts:

- Volume assumptions
- Price assumptions
- Component forecasts

250 The details presented will provide a thorough description of each assumption utilised in the forecast model, the reasoning behind the chosen values and briefly mention which components they affect.

251 The discussions of component forecasts will provide a detailed explanation of the relationship between the relevant assumptions and each cost component, their forecast cost and the expected range of costs given the uncertainties in the forecast.

3.2 Volume assumptions

252 The volumes required for several components of the forecast are driven by common factors. These drivers are:

- Market Length (NIV)
- Volume of wind generation
- Nuclear generator availability
- System requirements for compliance with NETSSQSS
- Demand forecast
- Volume of margin actions

3.2.1 Market length (NIV) assumptions

253 Net Imbalance Volume (NIV) or market length, as discussed in the section 2, is a measure of the real time imbalance between demand and generation, which has to be resolved by National Grid via the acceptance of bids and offers in the BM or via pre-gate closure actions.

254 The forecast of NIV directly impacts the expected cost of energy imbalance and margin.

255 The difference between demand and self-despatched generation that forms NIV is largely dependant on the individual strategies of supply companies which are subject to a number of drivers, beyond the control or knowledge of National Grid. The same applies to generation owners.

256 As National Grid does not have access to any information on the specific approach of any supply or generation company, and because our focus is on the overall balancing costs, we use analysis of historic volumes and a view on market behaviour to derive our forecast of NIV. We welcome any comments from generators and suppliers on these issues.

257 The first step in our forecast of market length is to take an average distribution of NIV based monthly historic volumes, by EFA block since BETTA go-live. This enables both within year and within day seasonality are captured along with the ranges that have been observed. All data points are treated equally within this with no weighting given to any particular year.

258 Figure 21 illustrates mean monthly NIV since BETTA Go-live (dark blue line) and a 3-month rolling moving average (light blue line) to smooth the data and facilitate analysis of the behaviour of this driver.

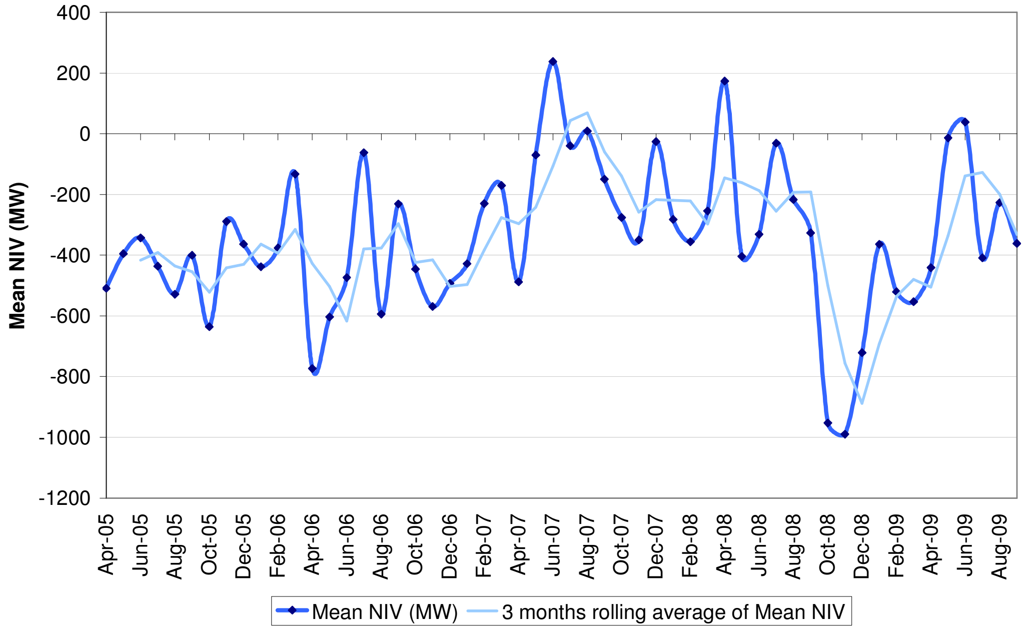

Figure 21: Mean NIV since BETTA Go-live

259 Visual inspection suggests that between April 2005 and March 2007, mean monthly NIV has been relatively stable (within a natural monthly volatility) around 400 MW long (negative). From April 2007 (and especially after November 2007) to September 2008 there seems to have a step change, bringing NIV to a relatively stable position around 200 MW long. Our current view is that this shortening change represents the market participants' learning curve as they gain experience in terms of how costs associated with management of the risk of being short may outweigh the penalties avoided.

260 The last quarter of 2008 sees a significant lengthening of the market, most likely caused by the recession and the consequential demand reduction not anticipated in the long term contracting strategy of market participants. At the beginning of the 3rd quarter of 2009, NIV seems to have returned to pre-recession levels, possibly reflecting the adjustment of market participants' contracts portfolio to reflect the reduced demand.

Question 3: Is historic market length a suitable proxy for future market length?

Question 4: Do you agree with the conclusions we have reached with respect to the observed changes in NIV since BETTA go-live? If not, why not?

261 The baseline forecast produced from the average of all years will not take these trends in to account. In addition, unusual events, such as the abnormally long October and November seen in 2008, are not expected to be repeated as the causes have been corrected for by the market. However, the data arising from the historic data will alter the average value that includes them.

262 In order to reflect the changes that have been observed, and described above along with our perceived drivers, we apply a set of offset to our forecast, so that the mean monthly and yearly NIV better reflect the observed historic data and our belief as to the likely future outcome..

263 The first offset applied was on the months of October and November, as the extremely long NIVs observed in these months last year are not expected to be repeated. Illustrating with numbers, the simple average of all years data for these months would yield mean NIVs of around 570 MW long for the months of October and November 2011. Our proposal is to offset those months by 200 MW, bringing their mean NIVs to around 370 MW long, which is in line with historic levels for these months.

264 The application of equal weightings to all years since BETTA yields an expected yearly mean NIV of around 320 MW long. As explained in paragraph 259, we expect mean NIV to return to around 200 MW long, so a second offset of 120 MW has been applied through the whole year in order to align the forecast length with this expectation.

265 Other possible NIV scenarios would be:

- Not applying any offset, reflecting a possible economic recovery in a slower pace than expected by the market
- Applying a 240 MW offset, reflecting a possible economic recovery in a quicker pace than expected by the market

3.2.1.1 Effect of Wind on NIV assumptions

266 Within the assumptions affecting market length, a possibly important driver is the effect of wind generation on NIV. The incentive for maximising generation output provided by the ROCs and anecdotal experience suggest that wind generation is more likely to "spill" its output into the system instead of contracting it, which would have the effect of making NIV longer as the contracted value would be unchanged but additional generation present.

267 In addition, given the intermittent nature of wind generation, if wind farm owners were to contract their expected output, the volatility caused by deviations from this expected value would cause NIV to become more volatile.

268 Both the effects of wind on mean NIV and its volatility were considered as part of our forecast model. Our historic data (Figure 22 and Figure 23 below) suggests that 28% of the expected wind generation visible to National Grid will be spilled (for every 100 MW of expected wind generation, NIV will get longer by 28 MW) and that wind volatility (standard deviation) affects NIV by 8% (every 100 MW of wind standard deviation causes NIV standard deviation to increase by 8 MW).

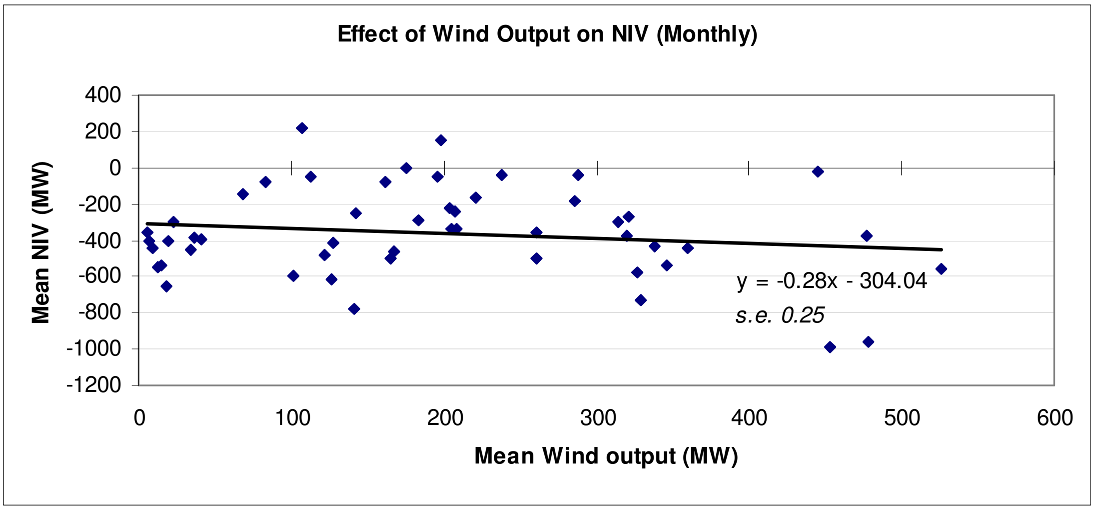

Figure 22: Effect of Wind on Mean NIV since BETTA Go-live

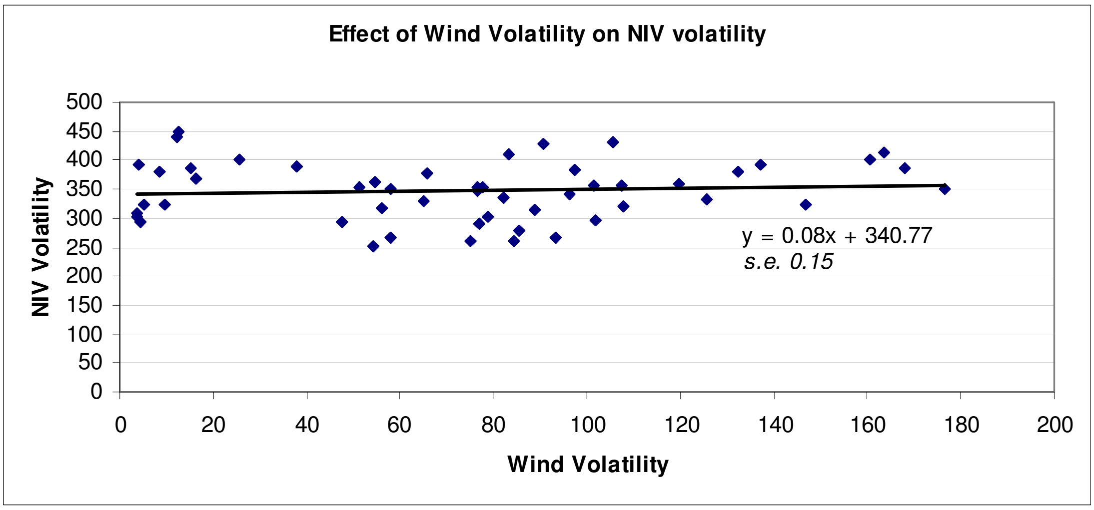

Figure 23: Effect of Wind on NIV volatility since BETTA Go-live

269 The above figures, however, have low statistical significance (as measured by the standard errors of the linear regression), casting doubts over the evidence of these effects. We recognise that one variable regression is not the best practise, but given that it is very unlikely that Wind output holds strong correlations with other variables affecting NIV, we do not believe this analysis suffers from omitted variable bias.

270 Based on this statistical analysis, for now we are leaving the effect of wind on NIV out of our forecast, but we are seeking views from the industry on how wind is expected to affect NIV. As the volume of data available for analysis increases, further analysis can be completed to confirm the statistical significance of the above figures.

Question 5: What do you believe is the impact of wind on market length at this time; how do you see this varying as wind penetration increases and what do you believe are the key drivers? What additional analysis could be carried out to determine the current and / or future impacts?

3.2.1.2 NIV forecast scenarios

271 As previously mentioned, our current base case for market length is based on an average of historic NIV since BETTA go-live, with offsets applied to correct for the abnormally long markets of October and November 2008 as well as to bring the mean yearly value to our expected level of 200MW long.

272 Figure 24 below illustrates four possible scenarios

- the green line is our base case including the described offsets (equal weightings, 200 MW offset applied in October and November and an additional 120 MW offset applied through the whole year)

- the purple line is the base case with an further 120 MW offset applied through the whole year, making an offset of 240 MW in total (earlier recovery from recession)
- the orange line is the base case, but with no offset (later recovery from recession)
- the red line is the later recovery from recession scenario, with wind generation making NIV longer and more volatile.

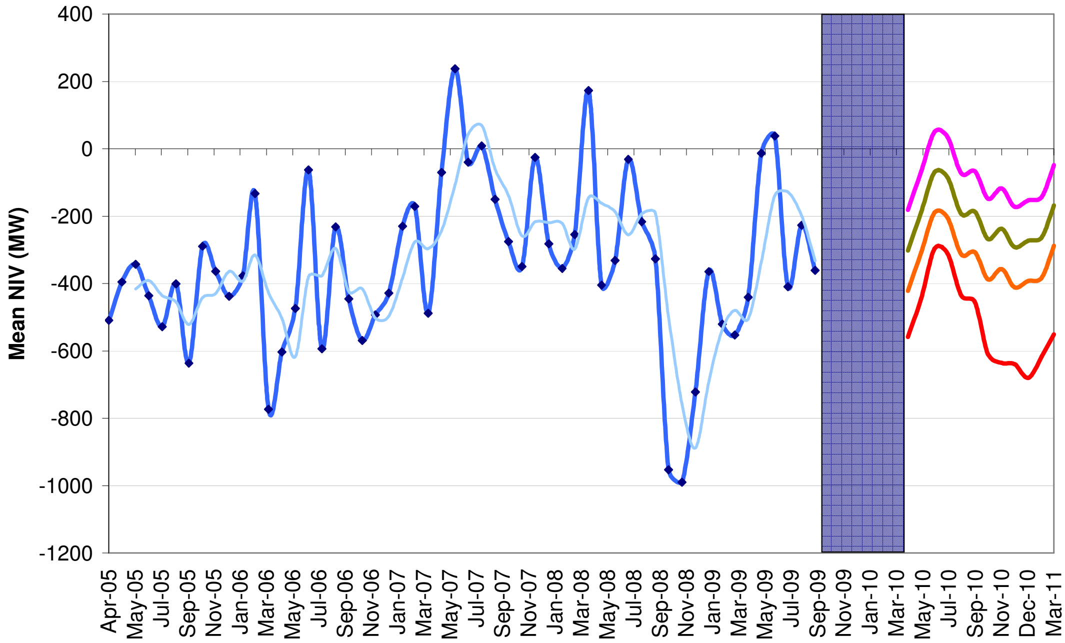

Figure 24: NIV scenarios

273 The forecast for NIV directly leads to the forecast volume for Energy Balancing and NIA.

> Question 6: Do you agree with our base case scenario for NIV? If not, which scenario should be used and why?
>
> Question 7: Are there any other factors or scenarios that you believe should be considered in deriving a NIV forecast?

3.2.2 Volume of wind generation

274 There is a major building programme ongoing with respect to the construction of new wind turbines, principally in Scotland. Based on the current signed connection agreements and the rate of construction that is visible it is forecast that connected wind capacity will grow by 100MW per month across the forecast period.

275 The Scottish constraint model uses actual connection dates, where these are available, as specific wind farms have significant impact on constraint costs due to the geographical nature of constraints and a number of outages are linked to connection of these wind farms.

276 As energy components are less sensitive to wind farm locations and the date at which production starts from any given location can vary dramatically, the energy model uses an average increase of 100MW of installed wind capacity per month. This allows for early connection where this is not outage dependent and also for delays to the start of production after transmission reinforcements are complete. This is based on the current signed connection agreements and the rate of construction that is visible.

277 In each case the installed wind capacity will increase from 4.1GW at the end of 2009/10 to 5.3 GW by the end of March 2010.

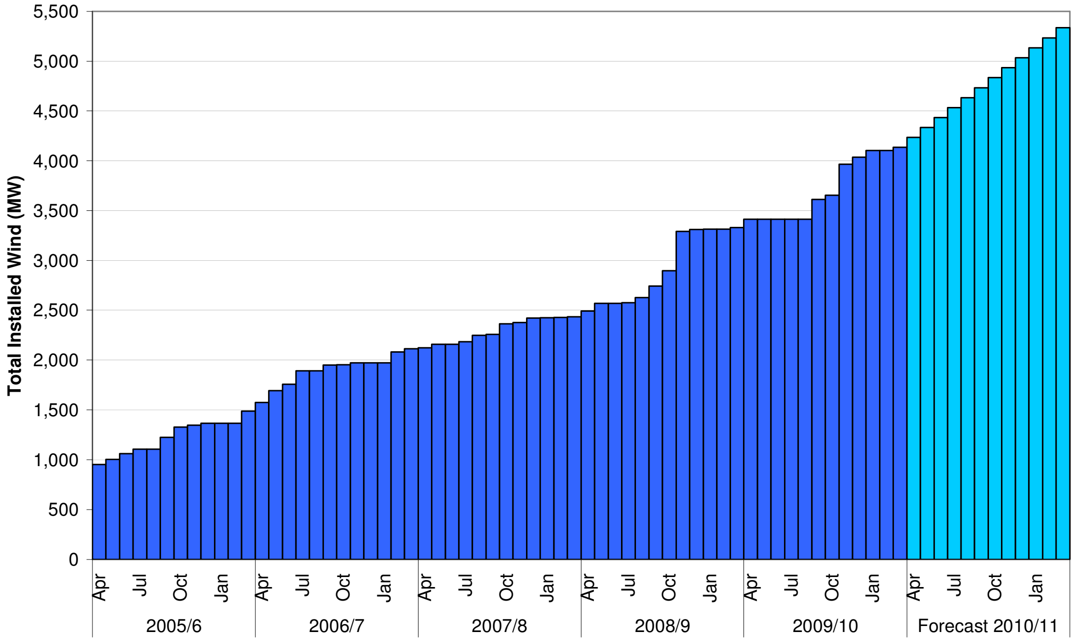

Figure 25: Installed wind capacity

Question 8: Do you believe that installed wind capacity will increase as indicated? If not, please indicate how you believe the rate will change and why.

278 The relationship between installed capacity and energy produced is given by the load factor. We are assuming that wind generation load factor will remain at the same level as the historic data available to us. The graph below illustrates the monthly mean load factors (i.e. the average wind output divided by the installed capacity per month in the historic data) and the 95th percentile (i.e., observed load factors have been below those figures for 95% of the time in each month). Peak is defined as the hours between 7am and 7pm.

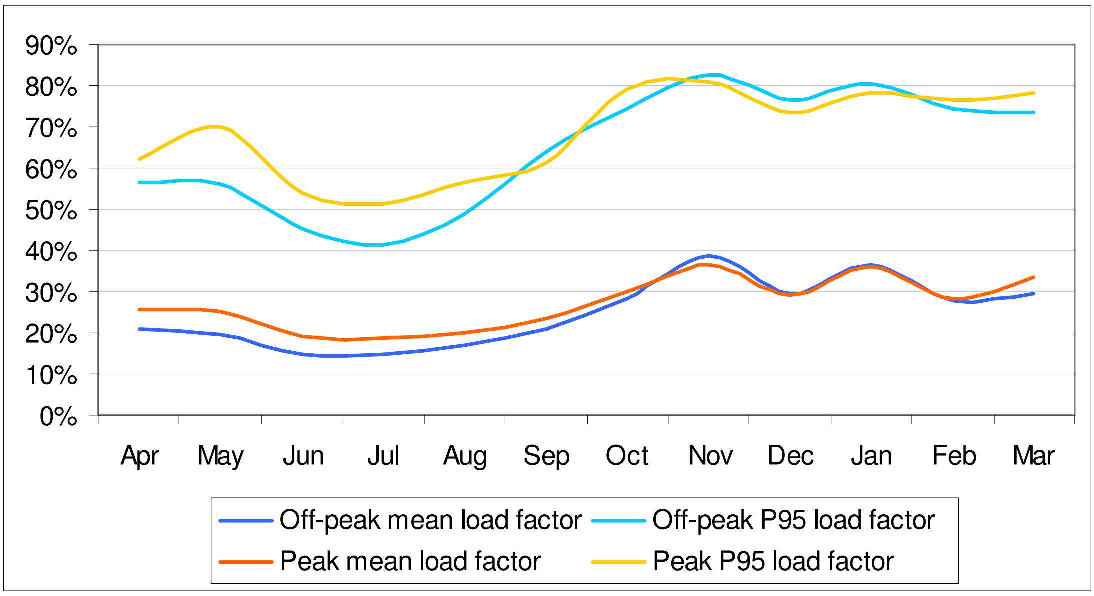

Figure 26: Wind load factor

279 The expected wind generation directly affects margin and footroom costs as a result of variability of output and inflexibility respectively. These effects are discussed further in section 2.5.4. As discussed earlier, the effect of wind generation on NIV is uncertain, to which we are seeking views.

3.2.3 Nuclear generator availability

280 The only other generation type that is explicitly utilised as an input to the forecast is Nuclear. This generation type is considered to be of particular importance given its inflexibility and, therefore, its impact on footroom costs. The nature of the impact of inflexible plant on footroom is explained further in section 2.5.6.

281 At the moment, we are using a repetition of 2008's summer output for summer 2010 and the 12 month average thereafter, as illustrated in the figure below.

282 Simply applying a 12 month average to the whole year at this point would have the undesirable effect of capturing the low availability of late 2008, misleading the forecast to a lower figure.

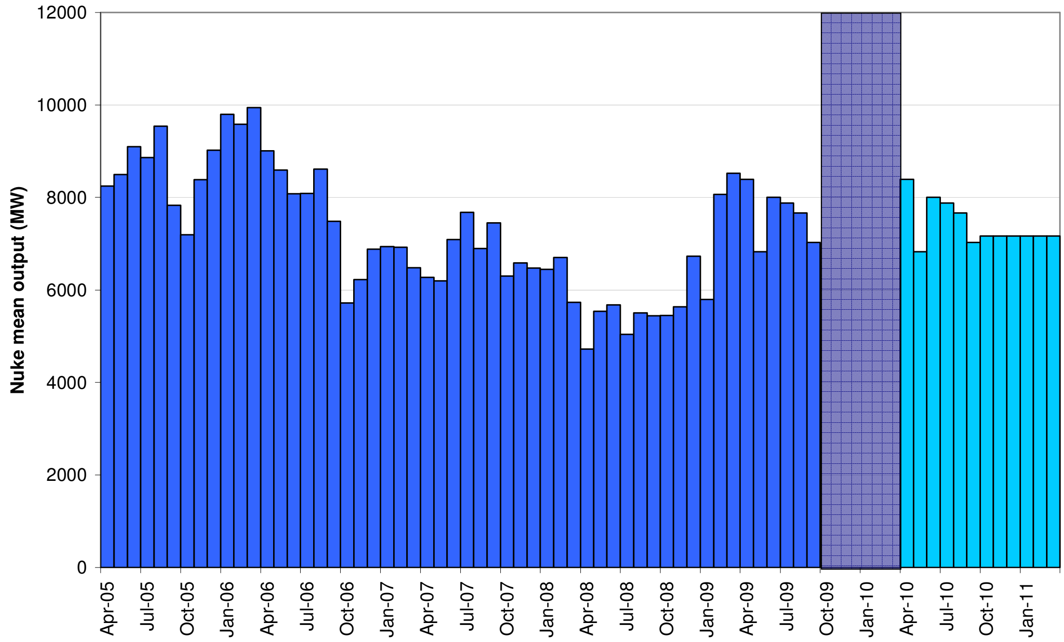

Figure 27: Nuclear output

283 For the final proposal, we consider it appropriate that the 12 months average throughout will be used. This assumption has been used as improved availability is expected to continue as seen in recent months. As such this measure should give a reasonable estimate of the output that this generation fleet will achieve going forward.

284 Using a data set for a longer period will include the low availability observed during the refurbishment outages of 2008 and would not capture the improved availability expected, and indeed seen, following the successful completion of these significant works.

Question 9: Do you believe that nuclear generation will maintain its current level of availability?

3.2.4 System requirements for compliance with NETSSQSS

285 The volume procured for certain services depend on the requirements of the National Electricity Transmission System Security and Quality of Supply Standards[40] (NETSSQSS). The forecast for energy components assumes that these requirements will not change. Whilst this has been assumed in the forecast, it is worth noting this may change in the future as part of the fundamental review of the NETSSQSS and investigations

[40] http://www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode/

in to the 27th May 2008 low frequency incident[41] may result in a change to these requirements.

286 Assumptions used to forecast volumes to meet NETSSQSS requirements are described by component below.

3.2.4.1 Response

287 The requirement for frequency response, as discussed in section 2.2.5, is prescribed to ensure sufficient changes in energy output are delivered to arrest falls or rises in frequency in the event of sudden loss of generation or demand. The requirement is driven by the largest system loss permitted by the NETSSQSS and system demand. The largest loss has been assumed to remain at the current level. This will be reviewed against the outcome of the fundamental review of the NETSSQSS, due in 2010. This will not be available until after the incentive scheme commencing April 2010 is agreed.

288 The response requirement to meet NETSSQSS requirements is converted to a volume of BM response actions using a multiplier, based on the response capability of the GB generation fleet, taking account of historical performance according to the following formula:

Response Volume = Response Requirement / Response Multiplier

289 The multiplier used for low frequency response is 0.55. This is the average response delivered per MW of headroom across the GB generation fleet. For example if the largest loss of generation on a day gives rise to a response requirement of 1320MW then, based upon the multiplier of 0.55, 2400 MW of responsive generation headroom will be needed to cover this loss.

290 The multiplier used for high frequency response is 0.7. This is the average response delivered per MW of footroom across the GB generation fleet. For example if the largest loss of demand on a day gives rise to a high frequency response requirement of 1000MW then, based upon the multiplier of 0.70, 1430 MW of responsive generation footroom will be needed in order to provide this response.

291 These parameters are reviewed periodically. They are forecast to remain at 0.55 and 0.7 for 2010/11 and 2011/12 as there is no significant change in generator characteristics (i.e. average response capability of the generation fleet) anticipated in the next two years.

292 The requirement for response is met from generators as a mandatory service and from commercial services remunerated via tenders from generation and demand side providers.

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[41] http://www.nationalgrid.com/NR/rdonlyres/E19B4740-C056-4795-A567-91725ECF799B/32165/PublicFrequencyDeviationReport.pdf

293 When dispatching units to carry frequency response a number of factors need to be considered in addition to the requirement. These factors include the plant mix available and if the system is limited by the amount of low frequency or high frequency response available. Improved optimisation processes have allowed these factors to be managed in such a way that response holding volumes have reduced over the past year whilst maintaining the same requirements and system security.

294 The forecast for provision of response from generation is based on the 12 month rolling average (as illustrated in Figure 28). This captures a marginal reduction in volumes, due to the increased optimisation of processes within the control room as described above. The historic 24 month average is 7% higher than that of the 12 month average, reflecting the reduction in dispatched volumes over this period

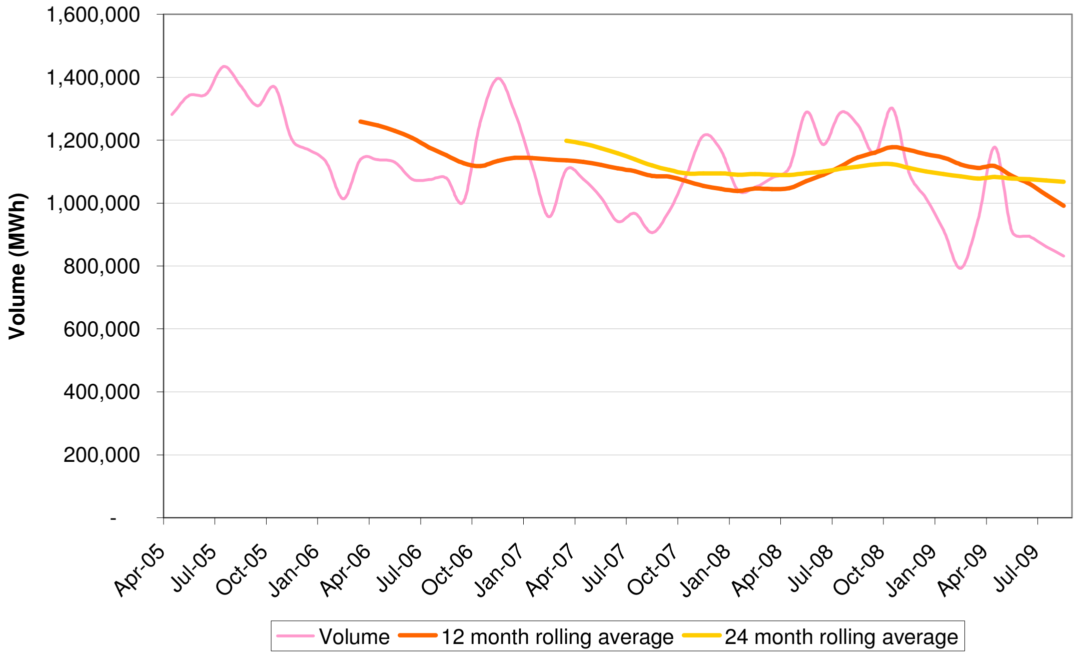

Figure 28: Mandatory Response Volumes

295 When a generator self dispatches at full output, there can be a requirement for actions to position this generation at a lower operating level via BM actions in order to provide low frequency response. On any given day a number of units will need to be positioned in this way in order to economically provide the required frequency response services. The majority of the time, the system is constrained by the requirement for low frequency response. When providing low frequency response, a generator will also provide high response services, thus also meeting the high response requirement.

296 BM actions to position plant in order to provide high frequency response are primarily required over night during the summer. Over peak periods[42], there is sufficient flexible plant synchronised for the

[42] Typically from 07:00 to 19:00

requirement to be met without further action. Volumes of BM actions taken to position generators to provide high frequency response are also related to Footroom volumes, as when National Grid de-synchronises one unit, offers will be taken from other units to raise their output level from their minimum stable level (SEL) to the point where they can provide high frequency response.

297 Frequency Response can be provided by either static (e.g. triggered) or dynamic (constantly varying) providers. The volume of static and dynamic response providers are assumed to be the same as the ones currently available, i.e. including the reduction in static provision following the closure of major demand-side provider.

298 National Grid is working with new providers although the volumes expected from these in 2010/11/12 are unlikely to be significant. The forecast assumes that all current providers remain available as we have no information to indicate otherwise.

Question 10: Do you agree with the assumptions made in producing a frequency response volume forecast? If not, please indicate why not.

3.2.4.2 Fast Reserve

299 Volumes of actions taken in the BM for Fast Reserve are split into volumes of offers and volumes of bids.

300 The volume of offers is based on a time trend, which has been selected based on historic data since BETTA (Figure 29 below). A clear monthly volatility is seen, which is repeated in the forecast. As discussed in Section 2.2.6, fast reserve is used to manage rapid changes in demand and generation output. The time trend[43] and the 12 month rolling average both point to an increase in offer volumes. This increase reflects the increased dynamism of the demand, most probably caused by the increasing capacity of embedded wind generation (which acts as a negative demand).

[43] This has the co-efficients 62t+9230 with standard errors of 26 & 760

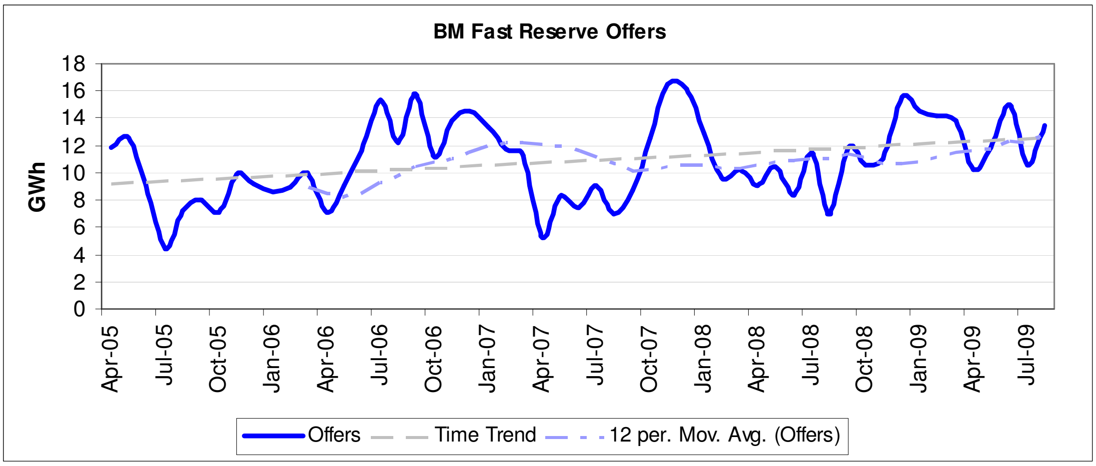

Figure 29: BM Fast Reserve Offer volumes

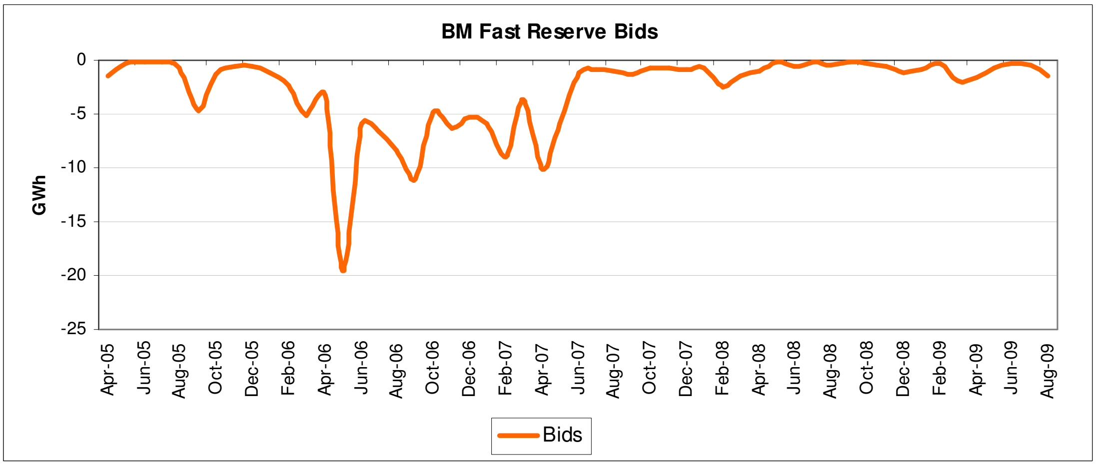

Figure 30: BM Fast Reserve Bid Volumes

301 For simplicity, given that the volumes of bids are very low, they are forecast as a repetition of the last 12 month's volumes.

Question 11: Do you agree with the assumptions made in producing a fast reserve volume forecast? If not, please indicate why not.

3.2.4.3 Reactive

302 The volume of reactive power required is related to system demand. The chart below illustrates the ratio between Lead volumes and the inverse of demand (blue line, left-hand axis) and the ratio between Lag and demand (orange line, right hand axis) since BETTA Go-live. This shows that Lag reactive (used to increase volts) is directly proportional to demand and that Lead reactive (used to reduce volts) is inversely proportional to demand.

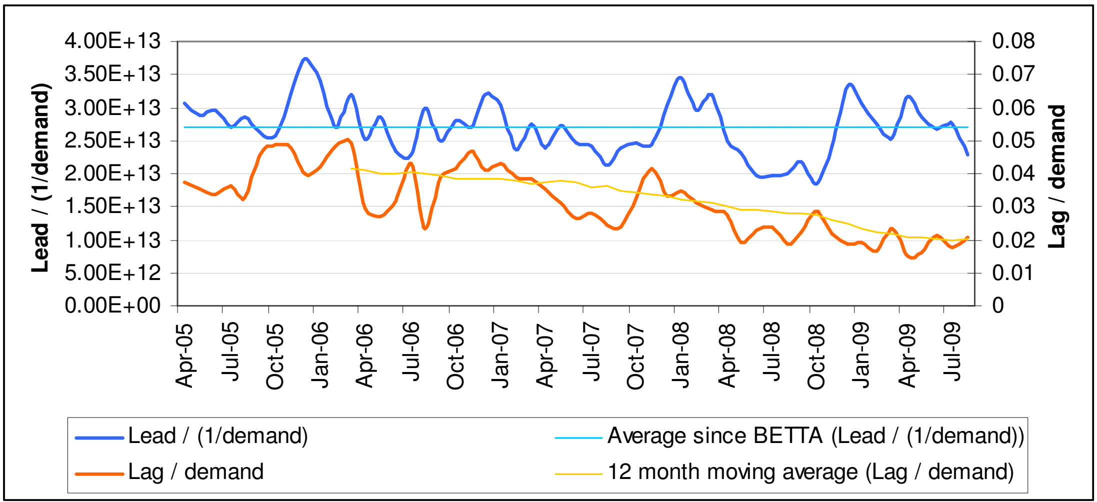

Figure 31: Reactive Power ratios to Demand since BETTA Go-live

303 The forecast for Lead is based on the monthly average of historic data since BETTA Go-Live, capturing both its stable nature (better seen in the graph above) and the monthly volatility, pictured in the graph below.

304 For Lag, the data from the last 12 months (the lowest since BETTA) is used, reflecting the limits of achievable reduction resulting from optimisation of control room process. . Further reduction would require either reduction to system security, installation of new reactive equipment or significant investment in the development of new optimisation tools.

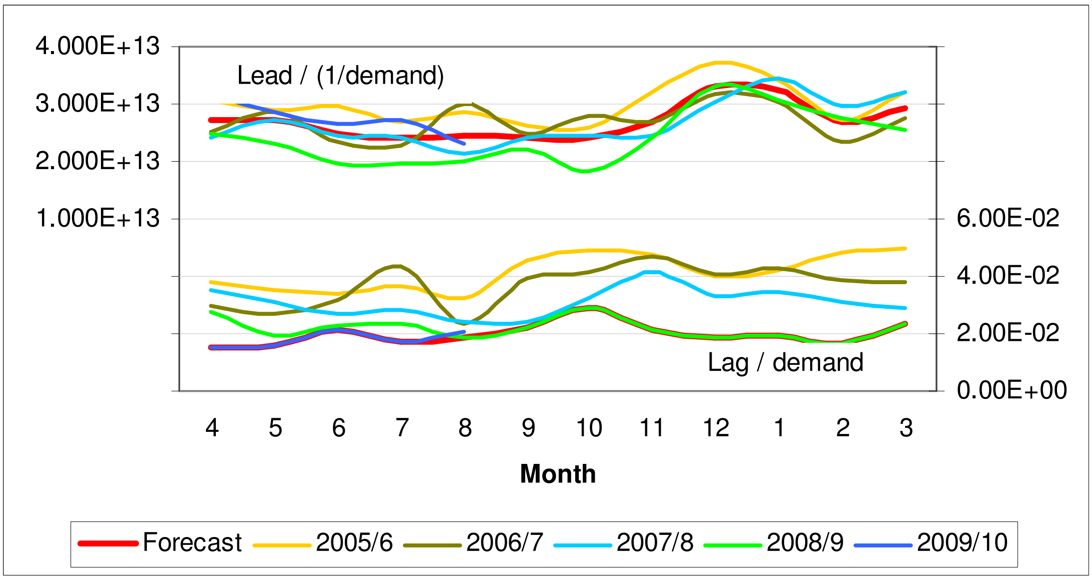

Figure 32: Reactive Power ratios to demand on monthly basis since BETTA Go-live

Question 12: Do you agree with the assumptions made in producing a reactive volume forecast? If not, please indicate why not.

3.2.5 Demand forecast

305 The main drivers affecting demand over a long period are weather related and economic conditions. In the forecast model, demand directly affects the costs of frequency response, footroom and reactive.

306 The demand forecast used in the model uses historical data for the last twelve months, scaled according to information about key factors.

- For the period for April to mid September 2010 (31/3/10 to 18/9/10), the demand for that period in 2009 has been used "as is" with no scaling factor applied. This accounts for seasonal changes in demand and reflects the belief that economic conditions will not inflate or depress demand for electricity compared to the same period in 2009 and 2010.

- For the period from mid September 2010 to end of March 2011, the demand from the same period in 2008 and 2009 was used. This data was scaled to 95% to account for the effect of the recession on demand. This is the same scaling that is currently applied to demand forecasts produced for winter 09/10. This scaling assumes that demand will be flat for 2010/11 as the economy comes out of recession rather than be further depressed or increase back to pre-recession levels immediately.

- Bank holiday, Christmas and Easter demands were shifted to adjust for the different days in each year.

307 When the Anglo-France Interconnector (IFA) is exporting this has the same effect on system operation as increasing the demand by 2000MW. To include this in the demand forecast, price spreads between the UK and France are considered. If prices in France are higher than prices in the UK by the reservation price, or more, for a given month it is assumed that the IFA will export UK power to France, effectively increasing demand in the UK. This reservation price is currently estimated to be £3/MWh based on historic data and trading intelligence.

308 The graph below illustrates demand since BETTA Go-live and the forecast demand utilised in this initial proposals.

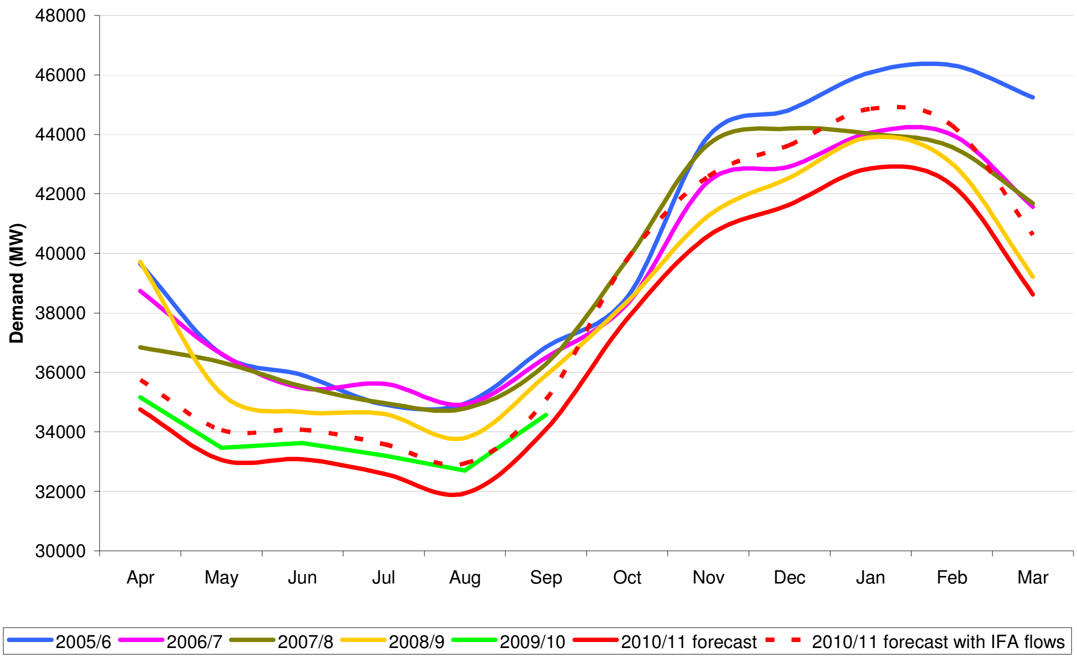

Figure 33: Demand outturn and forecast since BETTA Go-live

Question 13: Do you agree with the assumptions made in producing a demand forecast? If not, please indicate why not.

3.2.6 Footroom volume

309 The volume of footroom actions is calculated as a function of the inverse of the demand forecast, the higher the demand, the lower footroom volumes, and the expected inflexible generation output (sum of expected outputs of wind and nuclear generation, sections 3.2.2 and 3.2.3). The coefficients relating those drivers to the forecast volume were obtained by back testing the model with historic data.

3.2.7 Volume of Margin actions

3.2.7.1 Relationship between market length and margin requirements:

310 In previous BSIS forecasts a volume weighted average of historic outturn has been used to derive a forecast volume of margin actions that will be required. However, this area has been developed and we believe there is a relationship between market length and the volumes of margin we need to procure to maintain levels of security.

311 The relationship is based on the curve shown below. The coefficients for this relationship are based on our analysis of historic data with back testing in the forecast model to confirm the accuracy of the estimates[44].

[44] Standard errors are not available, as linear regression has not been utilised for this analysis

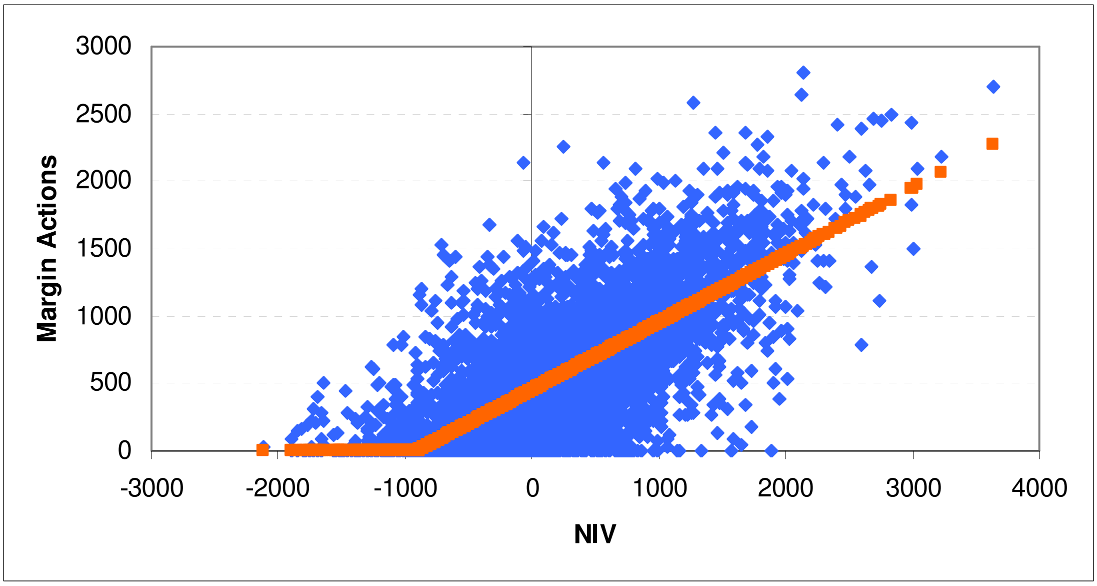

Figure 34: Relationship between Margin volumes and NIV

312 This shows that an increasing volume of margin actions are needed as the market length reduces, however this only starts from circa 550MW long. After this point 0.5MW of additional margin Offers are required for each 1MW change in NIV.

Question 14: Do you agree that the relationship between the volume of margin actions and market length is an appropriate input to the model?

3.2.7.2 Effect of Wind on Margin

313 As wind output is subject to intermittency, sufficient conventional plant must be available to meet demand in the absence of the indicated wind output. In order to do this we need to increase our Short Term Operating Reserve Requirements (STORR) according to the expected wind output for the relevant period.

314 National Grid has analysed the variation in output versus forecast for wind based generation. Based on our assessment of this variation, 41% of the forecast wind output visible to National Grid is required to be held on conventional units in order to provide cover for variation in this wind generation.

315 The amount of wind generation behind an active export constraint is discounted in this process because the de-loaded conventional generation[45] utilised to manage such constraints provide a natural margin in the event of a shortfall in wind output. In other words if the

[45] Conventional units are assumed to be pulled back as these units will have the more attractive bid prices.

wind generation is lower than forecast, the part loaded generation that was used to manage the constraint could be allowed to increase its output to fully utilise the system and so replace the 'lost' wind generation, rebalancing the system without violating the constraint.

316 This, however, relies on those conventional units running and not being completely displaced by the wind generation. If the conventional generation behind the constraint is not running or is completely displaced by wind, as we expect to happen with the increasing amount of wind generation connecting in Scotland, then the 'free' headroom previously provided by the part-loaded conventional plant will no longer be available. We welcome views from the industry on this topic.

Question 15: Do you believe that wind generation will displace conventional generation behind key boundaries? Do you believe that conventional generation behind constraint boundaries will stop running?

3.2.7.3 Volume and Cost of BM start up

317 As detailed in section 2.2.3 some units require additional payments in order for them to become ready for despatch in system operation timescales. These units are typically those that are infrequently run. As such, the costs of BM Start up have been modelled as a function of the volume of actions on oil fired plant. An examination of historic data since BETTA Go-Live shows a relationship between them (the orange line representing the modelled relationship).

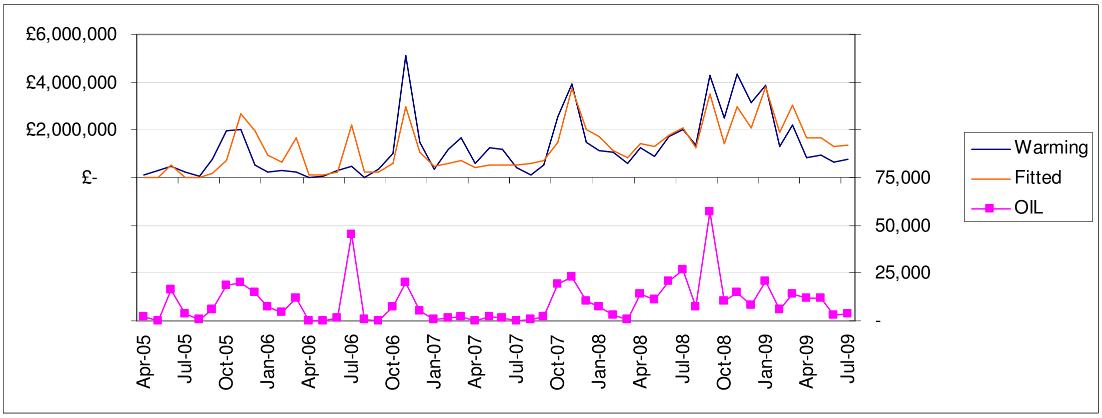

Figure 35: BM Start Up and volume of Margin actions from Oil units since BETTA Go-live

318 Oil running patterns are based on the forecast of margin volumes. Previously the cost of BM Start up has not been modelled explicitly.

3.2.7.4 Volume and cost of Constrained Margin Management (CMM)

319 As detailed in section 2.2.3, these CMM volumes refer to additionally synchronised units that have only partially been used to replace sterilised headroom behind export constraints. Examination of historic data (blue points) shows the relationship:

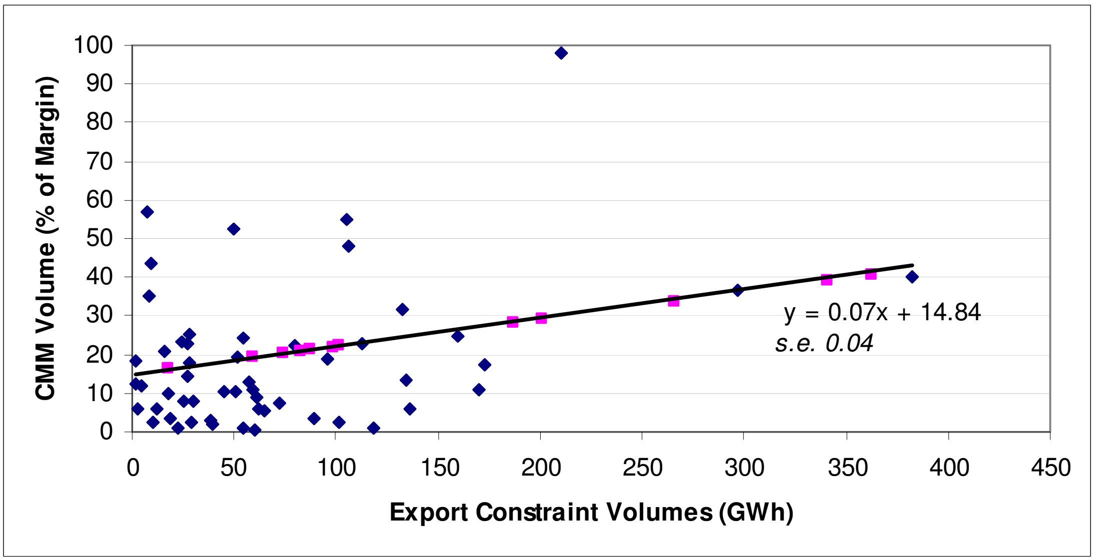

Figure 36: Relationship between export constraints and CMM

320 In determining this relationship, we recognise that the presence of outliers may be driving the coefficients of the regression as illustrated above[46], however the forecast volumes of export constraints (magenta points) lie within a range with low availability of historic data. We expect additional data to complement this analysis for the final proposals.

Question 16: Do you have any comments on the assumptions made in producing a margin volume forecast? Are there any other considerations that should be included in the margin volume assumption?

3.3 Price assumptions

321 The prices for several components of the forecast are driven by common factors. These drivers are

- Wholesale power and fuel prices
- Reactive power prices
- Prices in the BM
- Wholesale to Offer margin prices multipliers
- Ancillary service contract costs

[46] Although the coefficients are statistically significant to 3.5% level

3.3.1 Wholesale Power and Fuel Prices

322 One of the most important assumptions in the forecast is the expected wholesale price for power in the UK, in France and the clean spark spread in the UK.

323 National Grid is partially[47] protected from variations in wholesale power price (as well as changes in market length) by the Net Imbalance Adjustment (NIA) term contained within the incentivised cost calculation.

324 We utilise the forward market price curves from Argus with Carbon prices and Euro to Sterling Pounds exchange rates obtained from Bloomberg. These provide a relevant external, transparent and well understood market based index.

325 The forward price curve utilised in this forecast was obtained on 05-Oct 2009, representing the most up to date value at the time the forecast process was started and takes the values as detailed below:

05/10/2009	UK BLSD	UK PEAK	FR BSLD	FR PEAK	UK SPARK	Carbon
Q1 2010	£ 39.70	£ 48.25	€ 59.35	€ 81.25	£ 12.79	
Q2 2010	£ 37.80	£ 45.75	€ 40.35	€ 54.60	£ 12.49	
Q3 2010	£ 38.60	£ 47.13	€ 42.50	€ 59.70	£ 13.15	
Q4 2010	£ 45.15	£ 55.18	€ 59.00	€ 85.80	£ 11.40	
Summer 2010	£ 38.20	£ 46.45			£ 12.82	
Winter 2010/11	£ 47.05	£ 56.10			£ 10.73	
Summer 2011	£ 45.25	£ 54.05			£ 11.67	
Winter 2011/12	£ 51.60	£ 60.50			£ 10.62	
2010			€ 50.25	€ 70.00		€ 13.40
2011			€ 54.65	€ 79.40		€ 13.92
2012			€ 57.00	€ 84.30		€ 14.70

Euro to GBP	0.919

Question 17: Do you agree that the Argus forward price values are an appropriate measure of wholesale prices over the forecast period? If not, please indicate why not.

Question 18: Do you agree that Bloomberg is a suitable source for Carbon prices and the Euro to Sterling conversion rates used within the forecast? If not please indicate why not.

[47] NIA parameters are calculated to obtain a best (not perfect) fit of historic data

326 In order to convert quarterly prices as quoted in the above table into monthly prices, we apply phasing factors based on historic data since BETTA:

April	96%	Q2 2010
May	94%	
June	110%	
July	109%	Q3 2010
August	91%	
September	100%	
October	91%	Q4 2010
November	111%	
December	98%	
January	110%	Q1 2011
February	96%	
March	95%	

3.3.2 SPNIRP

327 In order forecast NIA these raw wholesale values need to be converted to the short term measure SPNIRP. This is done via a matrix of multipliers based on the historic relationship between Peak and Baseload Wholesale prices and outturn SPNIRP values since BETTA go-live at different market lengths. These multipliers were derived by minimising the absolute error between predicted value and outturn across the study period. These values are unchanged since the final forecast for 2009/10.

3.3.3 Reactive Power prices

328 As detailed in section 2.3, the default mechanism reactive power prices are dependant on monthly power price and RPI. Both are directly input to the model, power price as used in the rest of the forecast from Argus and RPI from Experian Business Strategy, as illustrated below:

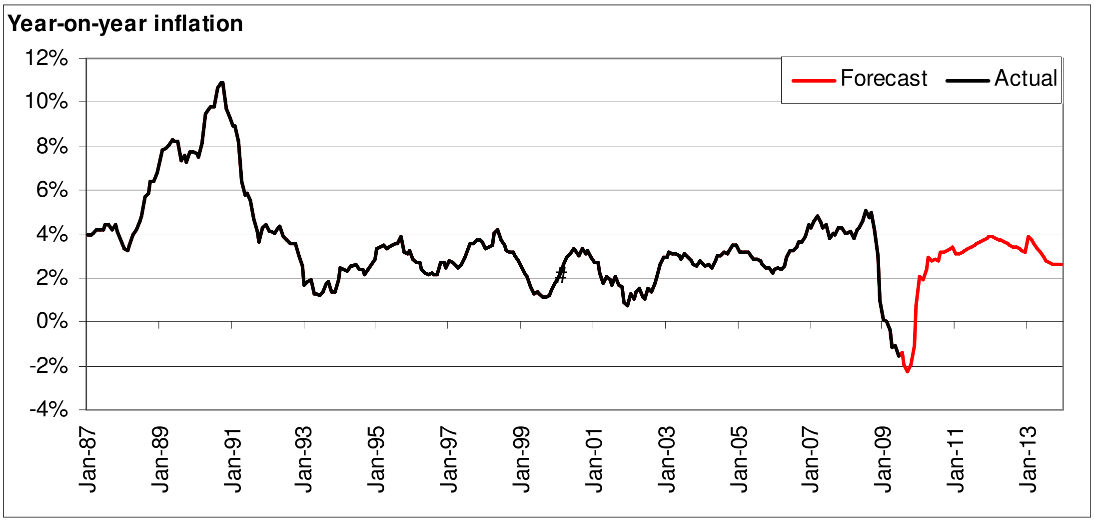

Figure 37: RPI forecast from EBS

329 The proportion of reactive volumes provided through the commercial mechanism has declined to zero. Thus we are assuming all reactive volumes for 2010/11 will be provided through the default mechanism.

3.3.4 Prices in the BM

330 The average Bid and Offer prices accepted in the BM depend on the prices submitted, which reflect the degree of competition in the BM, generator behaviour and the volume of actions required.

331 As discussed in section 2.5.2, there is a strong and relatively stable relationship between BM energy prices and electricity wholesale prices as measured by the SPNIRP term defined within National Grid's Transmission Licence. Multipliers are used to reflect this relationship.

332 Ratios between volume weighted averages of available BM Offer and Bid prices to resolve NIV and prevailing electricity wholesale market price (SPNIRP) were calculated based on historical data from April 2005 and back tested (i.e., actual wholesale prices are fed in the model and BM multipliers are changed to obtain actual BM prices) to get best correlation. These multipliers are reviewed and updated with outturn data.

333 Monthly values for Offers have remained between 1.3 and 1.7 across the majority of months since BETTA go-live. Since April 2007 this has been even more stable with more than half of the monthly values for Offers lying in the range 1.4 to 1.6. The expected case takes a central value for this range, 1.5 with the range being considered in the overall distributions. For Bids the values have remained between 0.7 and 0.8 over the same period. Again this range is taken in to account when calculating distributions

334 This allows a baseline value for energy within the BM to be calculated. From this value the costs incurred for other balancing services can be resolved including any premiums applied to that service.

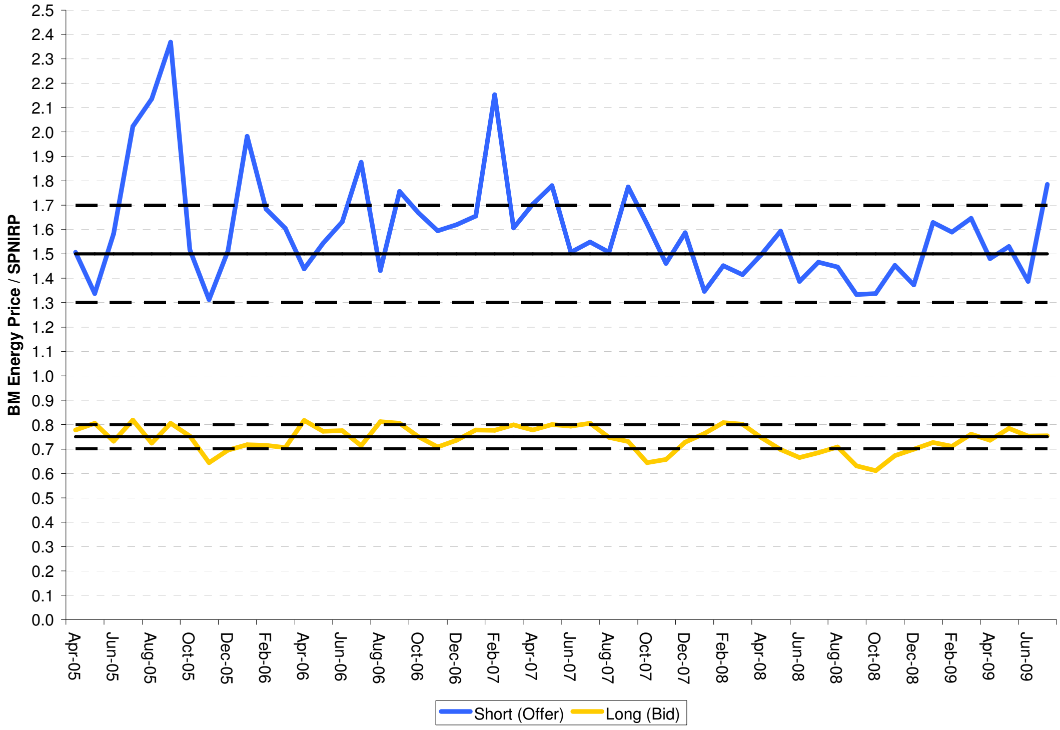

Figure 38: BM Prices to SPNIRP ratios

335 This gives an average price to buy energy in the BM of £73/MWh (short markets) and £28/MWh to sell energy (long markets) for 2010/11.

> Question 19: Do you agree with the assumptions made in producing a BM energy price forecast? If not, please indicate why not.

3.3.4.1 Price for Response BOAs

336 A relationship exists between prices paid to position generators to provide frequency response and BM energy prices, which is dependant on market direction. The coefficients for this relationship are based on regression analysis of historic data, as illustrated in the charts below (red dots, short NIV; black dots, long NIV).

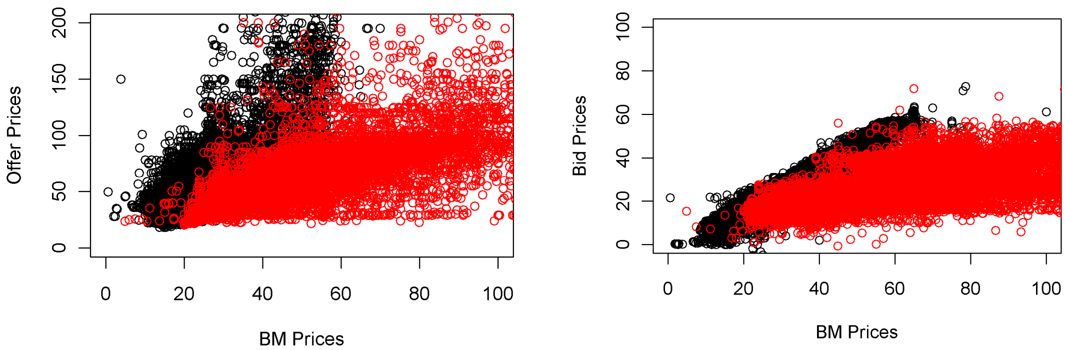

Figure 39: Response BOA prices as function of BM prices

337 These charts indicate that the price of Bids taken to position units in a long market varies in proportion to the prevailing price of energy in the BM, as would be expected. The same is true of Offers in short market. Offers taken to position plant to provide response in a long market (black dots, left hand graph) increase in price at a faster rate than the prevailing cost of energy in the BM. This means that when BM energy prices are higher it costs proportionately more to increase the output from units to provide response. For instance, if Bids are available to resolve market length at £40/MWh then an Offer to position plant for response may be around £65/MWh. Should BM energy prices increase to £60/MWh, an Offer for response may cost over £150/MWh. This makes it more expensive to position the unit to provide response due to the increasing spread between the Offer and replacement energy.

338 Conversely, for response Bids in a short market the Bid price of the unit carrying response changes at a lower rate than the increasing prices for energy in the BM. Indeed, response Bids remain in the range £20/MWh to £40/MWh throughout the range shown. As the price of replacement energy is increasing and the Bid is staying relatively stable, this results in increasing costs.

339 Within the forecast these relationships are used along with the forecast of BM energy prices to derive a forecast price for the BM actions to position plant to carry frequency response. This is carried out by applying the relationship from the charts to the forecast BM energy price distribution for a given month. The difference between this price and the BM energy price then gives a cost of taking the action.

340 These values result in Offers having a net cost of £30/MWh and Bids a net cost of £1.50/MWh in long markets. In short markets these values would become £6/MWh and £37/MWh respectively. As can be seen from these values, taking actions against the market direction results in higher costs.

> Question 20: Do you agree with the assumptions made in producing a BM Response price forecast? If not, please indicate why not.

3.3.4.2 Price for Footroom

341 Footroom costs are heavily linked to running regimes of inflexible generation at periods of low demand. For Footroom prices we are utilising the 12 month volume weighted average as this will not only capture the latest trends in price, including the applicable premiums, but is also consistent with the 12 month average used for nuclear availability.

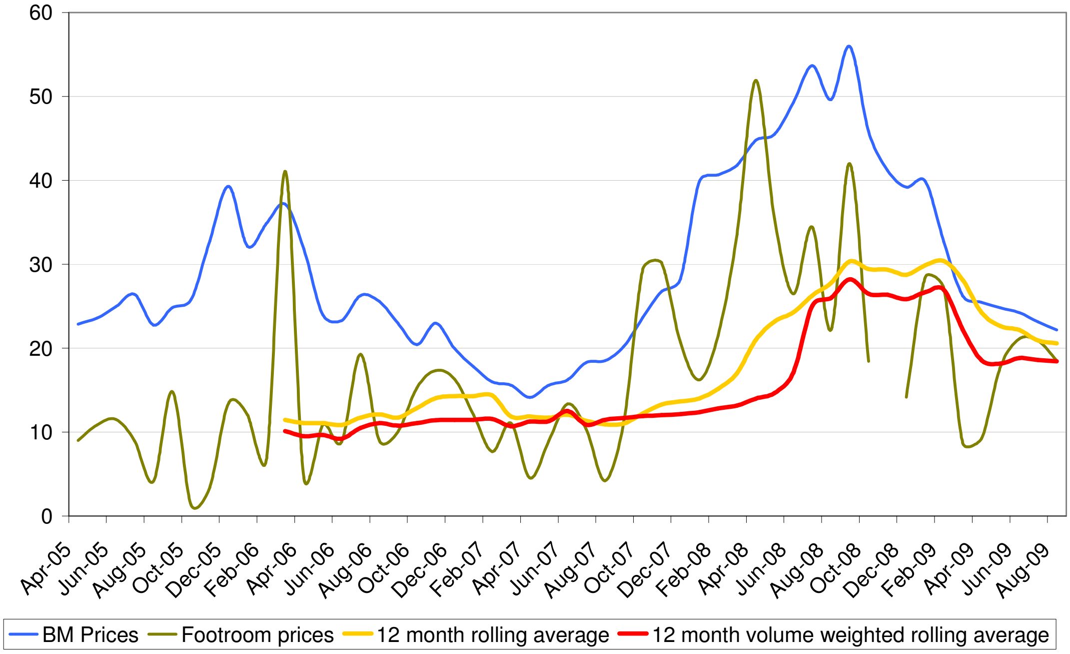

Figure 40: Footroom prices since BETTA Go-live

342 The drivers for the observed step change in the 12 months ending in July 2008 followed by a new change in the 12 months ending in April 2009 are still being investigated and we anticipate having more information prior to Ofgem consulting on final proposals.

343 This assumption was tested against using data for 24 months and using simple average. Using the simple average of 12 months, price would increase from £18 to £20. The simple average of 24 months results in price would increase to £24. Using the volume weighted average of 24 months would see the price going to £20. Thus using the 12 month volume weighted average does not adversely affect the forecast costs.

Question 21: Do you agree that a 12 month average of the prices for Footroom is a reasonable assumption? If not, please indicate why not.

3.3.4.3 Price for Fast Reserve

344 Costs are divided into BM (Offers and Bids), Balancing services and Other BS Fast Reserve. This section relates to the BM actions.

345 The offer prices are an average of historic prices for each month based on a perceived stability noted by visual inspection of historic data since BETTA. This average value is then used as the price for Fast Reserve Offers in the corresponding month of the forecast. This gives a premium of around £76/MWh on top of the BM Energy (circa £150/MWh gross) when taken across the year

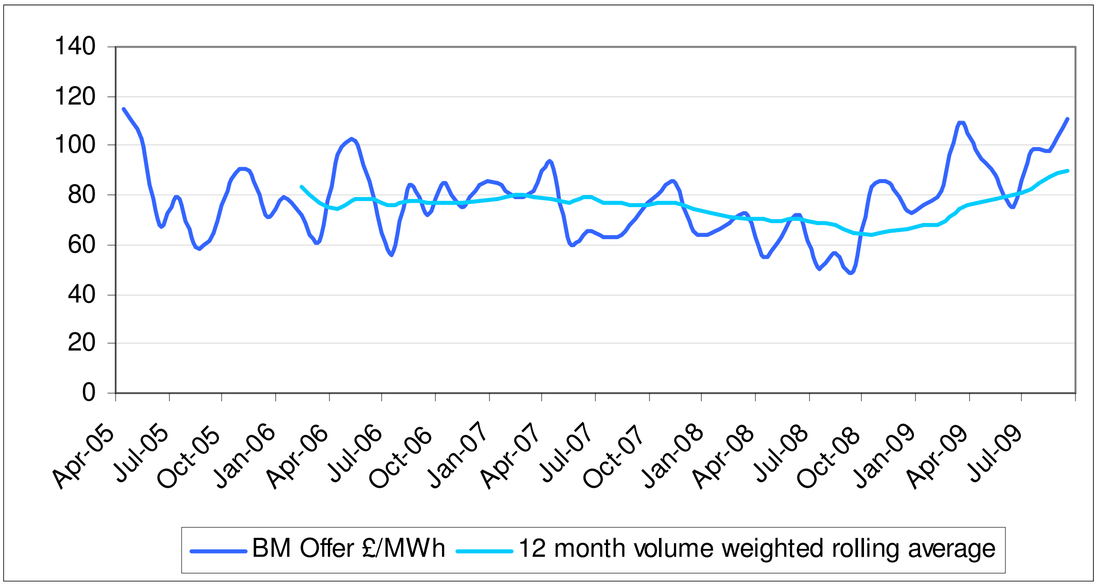

Figure 41: Offer prices for Fast Reserve since BETTA Go-live

346 Bid prices for BM Fast Reserve are taken as a function of BM energy prices as shown in the chart below. The relationship between prices in each area has been taken for each month since BETTA Go-Live and the average of these value used. Given the low volumes, they have very little impact on costs (<£1m/year).

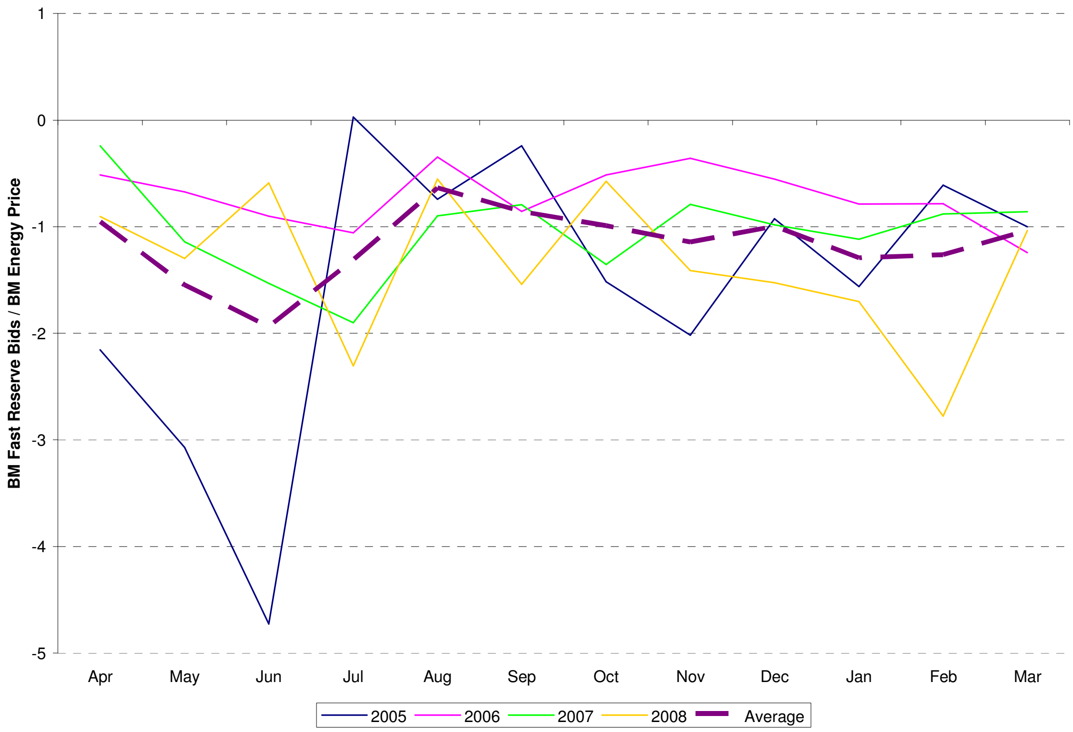

Figure 42: Relationship between BM Prices and Bid prices for Fast Reserve

Question 22: Do you agree with the assumptions made in producing a Fast Reserve price forecast? If not, please indicate why not.

3.3.5 Wholesale to Offer margin prices multipliers

347 The forecast volume for margin is based on market length, volume of reserve required, response providers and wind. The forecast volume is split into nine different ‘fuel types’ according to historic data of what plant has been utilised for margin actions.

348 A 12 month average has been calculated to give a volume of offers taken on the various fuel types to create margin, broken down in to BST and GMT seasons. Using this gives values for the volumes offers taken to create margin from gas fired units that appear to be too low (8% for BST and 26% for GMT) and increase the forecast costs by £30m as increased actions are assumed to be taken on more expensive fuel types.

349 To produce a more reasonable spread of percentages the average volume since BETTA Go-Live has been used to split the total margin volume into these nine fuel types and is used in the forecast. In the table below each column represents the proportion of the total volume in each season that is supplied by that fuel type.

	BST	GMT
COAL	*50%*	*23%*
GAS	*16%*	*38%*
OCGT	*2%*	*3%*
OIL	*3%*	*4%*
HYDRO	*2%*	*2%*
PUMPED STORAGE	*8%*	*11%*
UK TRADE	*10%*	*8%*
SOSO	*4%*	*8%*
FRENCH TRADE	*5%*	*3%*

350 The cost forecast for margin is then based on the proportion of volume provided by each fuel type and the price of actions of each fuel type.

351 For coal and gas fired units the offer price for each “fuel type” is calculated based on the historic ratio of accepted offer prices for margin to different external factors (wholesale fuel price, power price or long term average of historic offer prices). The external factor which then has the highest correlation with the historic offer prices for each “fuel type” has been selected and a volume weighted average of this ratio taken for the period August 2008 to July 2009. These values are presented here, alongside the ratio (multiplier) utilised in this forecast.

Fuel	Price Multiplier	Price used	Calculation
Coal	2.18	Baseload power price (£/MWh)	Volume weighted average of Coal Margin Offers / Baseload Price between Aug-08 and Jul-09
Gas	2.94	Clean Gas Price (£/MWh equivalent)	Volume weighted average of Gas Margin Offers / Clean Gas Price Price between Aug-08 and Jul-09
OCGT	261	Average of historic price (£/MWh)	Volume Weighted Average of accepted prices between Aug-08 and Jul-09
Oil	372	Average of historic price (£/MWh)	Volume Weighted Average of accepted prices between Aug-08 and Jul-09
Hydro	139	Average of historic price (£/MWh)	Volume Weighted Average of accepted prices between Aug-08 and Jul-09
Pumped Storage	154	Average of historic price (£/MWh)	Volume Weighted Average of accepted prices between Aug-08 and Jul-09
UK Trade	1	Peak power price (£/MWh)	Trades carried out for margin will be in Peak periods therefore at Peak price
SOSO	118	Average of historic price (£/MWh)	Volume Weighted Average of accepted prices between Aug-08 and Jul-09
French Trade	1.5	Peak power price in France (£/MWh)	Trades carried out with French interconnector counterparties will be at a premium to access the energy

352 The remaining multipliers, except trades, are based on volume weighted averages taken across the same 12 months from August 2008 to July 2009. The 12 month average has been selected as it recognises the importance of most recent data as being more representative for forecasting the future, while keeping the simplicity and transparency in the process.

353 UK Trades are assumed to be bought at Peak price and French trades assumed to be 1.5 times French Peak prices, allowing a premium to access energy.

Question 23: Do you agree with the assumptions made in producing a Margin price forecast? If not, please indicate why not.

3.3.6 Balancing Service contract costs

3.3.6.1 Response

354 The forecast for response holding costs is simply a volume multiplied by price, both based on the 12 months rolling average, reflecting the recent stabilisation of submitted prices for mandatory response.

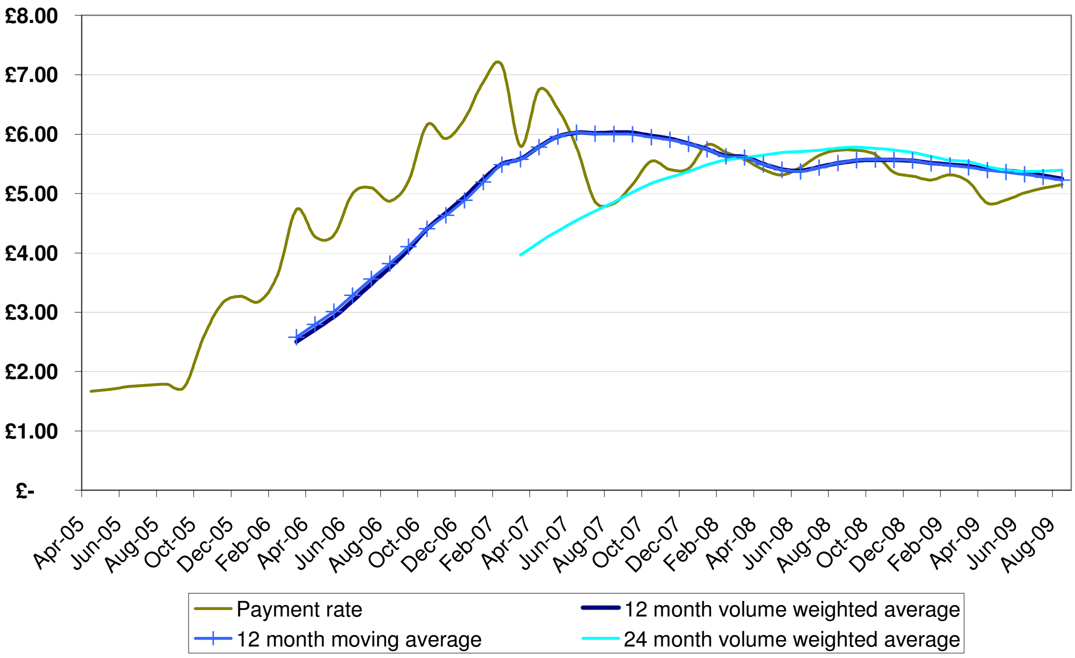

Figure 43: Mandatory Response price since BETTA Go-live

355 The volume weighted average of 12 months data is used to forecast price. The simple average was calculated and yielded the same result (5.25). Simple average and volume weighted average were calculated using 24 months data. Both yielded a slightly higher price (5.4), reflecting the stabilisation of submitted prices observed.

3.3.6.2 Fast Reserve

356 A relationship based on historic data has been derived between BM Fast Reserve and BS Fast Reserve prices.

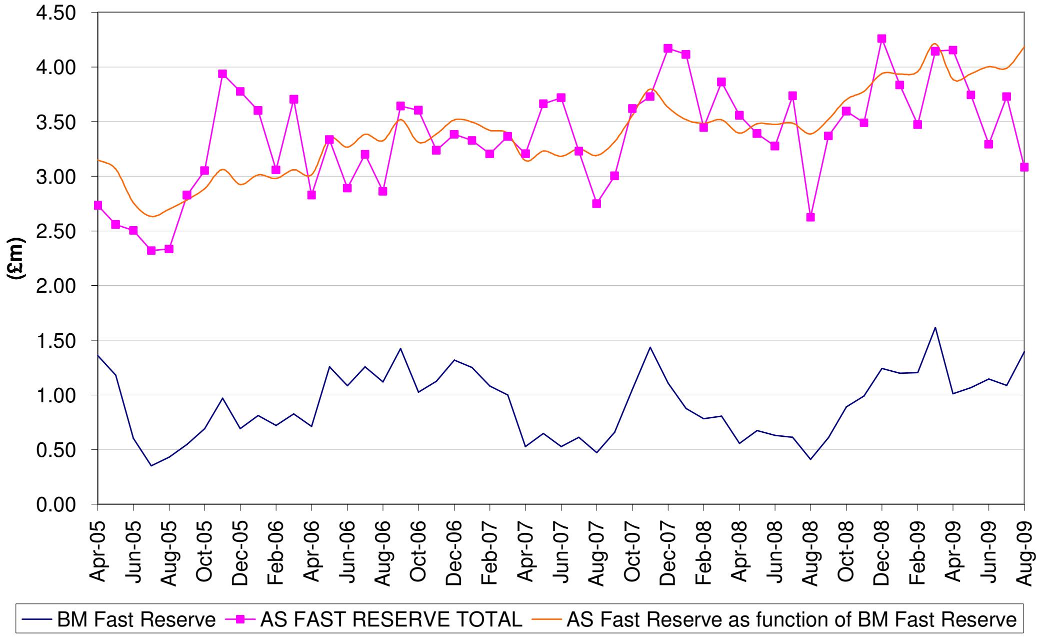

Figure 44: BM and BS Fast Reserve costs since BETTA Go-live

357 Based on the trend of BS Fast Reserve as a function of BM Fast Reserve, an increase in prices is forecast. This trend is believed to be due to providers increasing their costs, reflecting their internal costs inflation.

358 Other Fast Reserve costs are forecast along a trend based on historic data, which will be updated with additional outturn information prior to Ofgem consulting on final proposals. This trend has been taken over this period in order to represent the longer term trends in costs over longer than 12 month timescales. The trend used here takes the values 0.004t+0.42 with standard errors of 0.001 and 0.02 respectively.

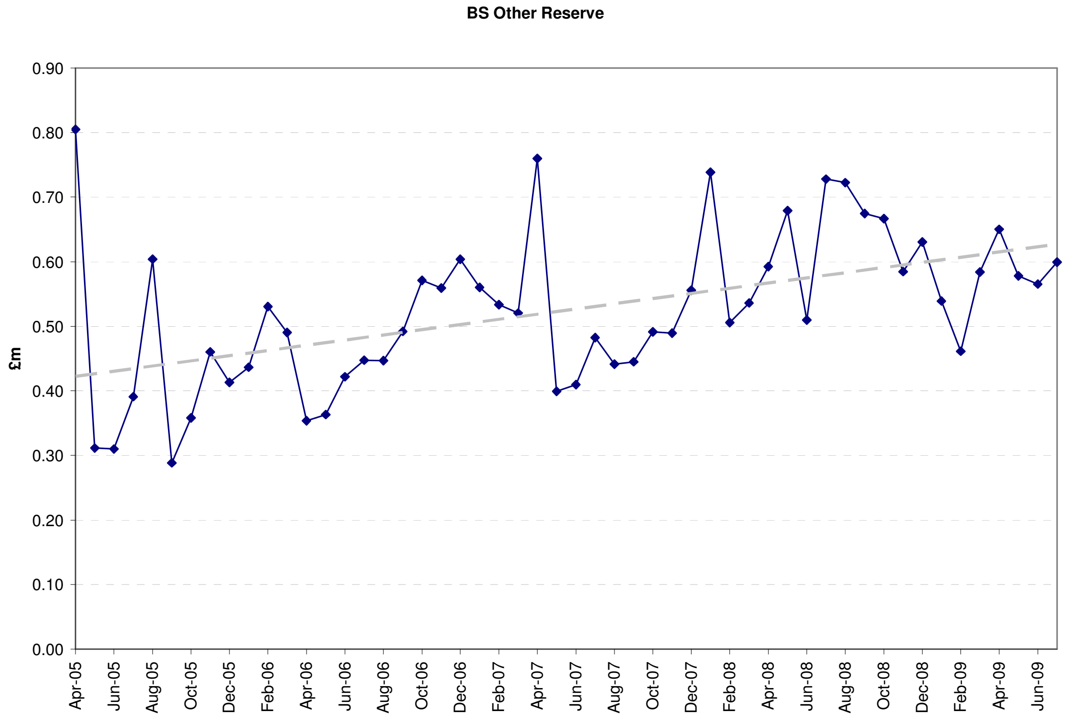

Figure 45: BS Other Reserve since BETTA Go-live

3.3.6.3 Short Term Operating Reserve (STOR)

359 Since there is a STOR tender approaching shortly, we have decided not to include the specific assumption on where we expect prices to outturn in 2010/11 in this consultation as it may influence tender prices. Our assumption however is contained within our BSIS and BSUoS forecasts detailed later.

360 To improve participation and reduce contract prices, we have been actively promoting STOR requirements to attract new providers through energy forums, holding Balancing Service open days and bilateral discussions.

361 Over the past three years we have made significant progress in developing the commercial contracts that we have in place with both BM and non-BM parties. These developments have been made in conjunction with the industry to try to stimulate the market. Examples of the major developments and work that we have undertaken are:

- Major (and regular) review of reserve and response services with active consultation and engagement through industry workshops
- Created the ability to tender long-term (e.g. 10yrs) to allow providers, where significant investment is required to offer a service[48], to more efficiently recover capital expenditure

[48] New providers often incur capital costs in establishing processes or assets to provide reserve services which they will seek to recover as quickly as possible.

- Reducing the providers risk of such a long term contract by limiting National Grid ability to amend terms

- Introducing a price indexation methodology to the tender process – this removes risks with long term tenders such as uncertainty against fuel costs

- Created the ability for a provider to submit a tender before investment commences – this removes the barrier of needing to demonstrate capability before a tender will be accepted.

Question 24: Do you agree with the assumptions made in producing a Balancing Services price forecast? If not, please indicate why not.

Question 25: Do you have a view on the future trend of STOR contract prices?

3.4 Forecast model results

362 The forecast model provides the expected costs based on the aforementioned assumptions. This represents National Grid's central view of where these costs are likely to outturn.

363 However, as there are a number of uncertainties in the outturn of all areas Monte Carlo simulations have also been performed using the application @Risk. These provide a range around which the costs can be considered along with a likelihood of occurrence based upon the level of variability in the input assumptions

364 As these simulations are based on a distribution of possible outcomes, and not National Grid's central view, the mean of these is often different from National Grid's central view of the outcome. This difference between central view and expected (mean) value is caused by the non-linear nature of such components.

365 For clarity, the summation of central views gives the initial forecast whilst the distributions inform the ranges around this value.

3.4.1 Energy Imbalance

366 The cost to balance demand and generation in a steady state condition. This component depends on power price, NIV and Wholesale to BM price multipliers.

367 The central forecast for 2010/11 is £26.4 million, with an expected (mean) value of £32.5 million and 80% probability of being between -£6.3m and £72.1m.

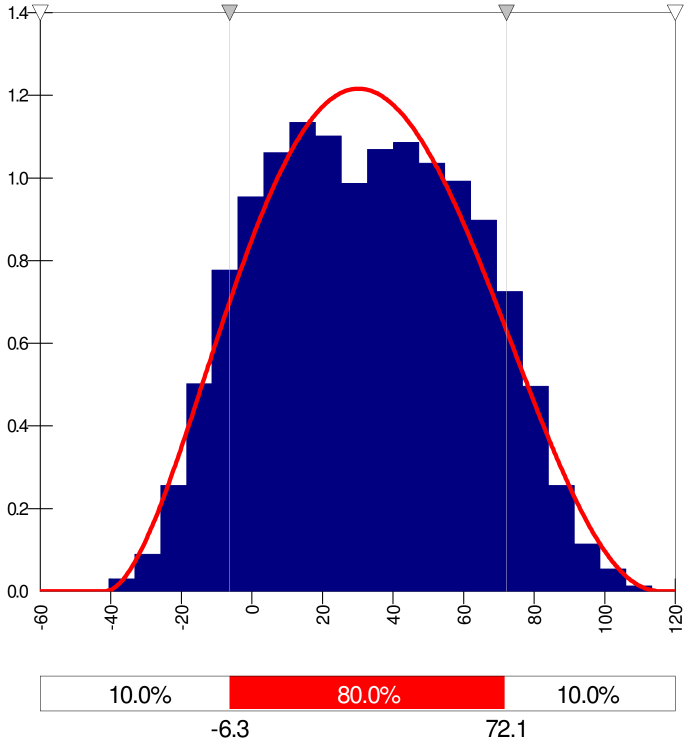

Figure 46: Energy Imbalance range of costs for 2010/11

3.4.2 Margin

368 The cost to ensure there is enough synchronised generation to cater for the infrequent combination of higher than expected demand and low levels of generation provided by the market.

369 This component depends on power and fuel prices, NIV, wind capacity, response providers, margin volumes, margin multipliers, warming trend, export constraint volumes, constraint to CMM ratio, STOR trends (or prices), wind on reserve, free headroom for wind

370 The central forecast for 2010/11 is £367.2 million, with an expected (mean) value of £366.0 million and 80% probability of being between £334.4m and £398.7m.

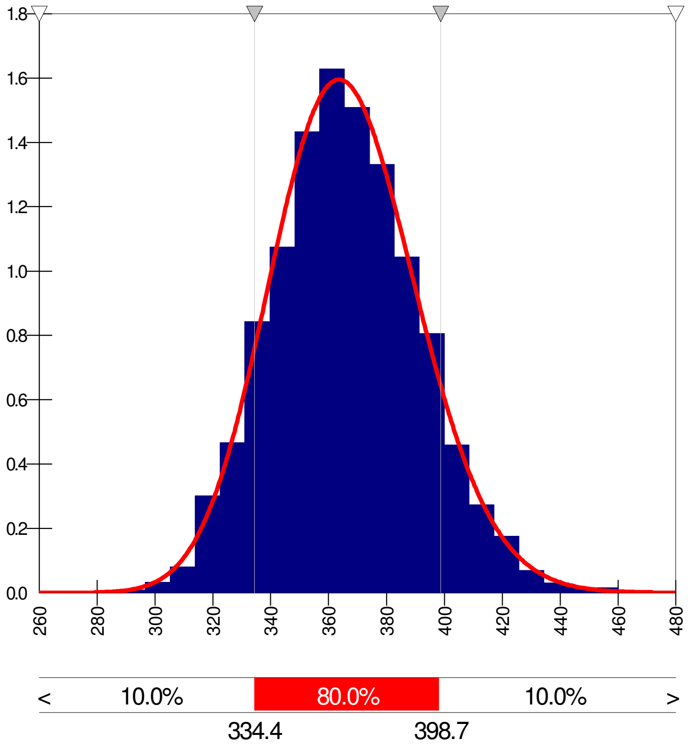

Figure 47: Margin range of costs for 2010/11

3.4.3 Footroom

371 The cost to ensure there is enough flexibility to cater for the infrequent combination of lower than expected demand and high levels of generation provided by the market.

372 This component depends on demand, wind capacity, nuclear availability and footroom price.

373 The central forecast for 2010/11 is £22.5 million (same as the expected (mean) value) and 80% probability of being between £18.0m and £27.2m.

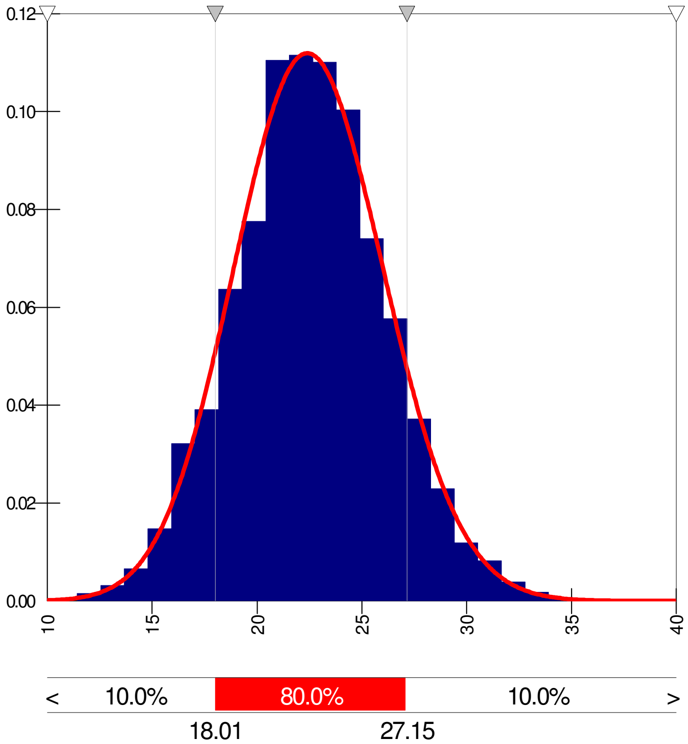

Figure 48: Footroom range of costs for 2010/11

3.4.4 Fast Reserve

374 The cost incurred to manage the frequency in periods of fast demand/generation changes, such as TV pickup and plant losses.

375 This component depends on Power Price and Fast Reserve trends.

376 The central forecast for 2010/11 is £72.4 million (same as the expected (mean) value) and 80% probability of being between £67.8m and £77.0m.

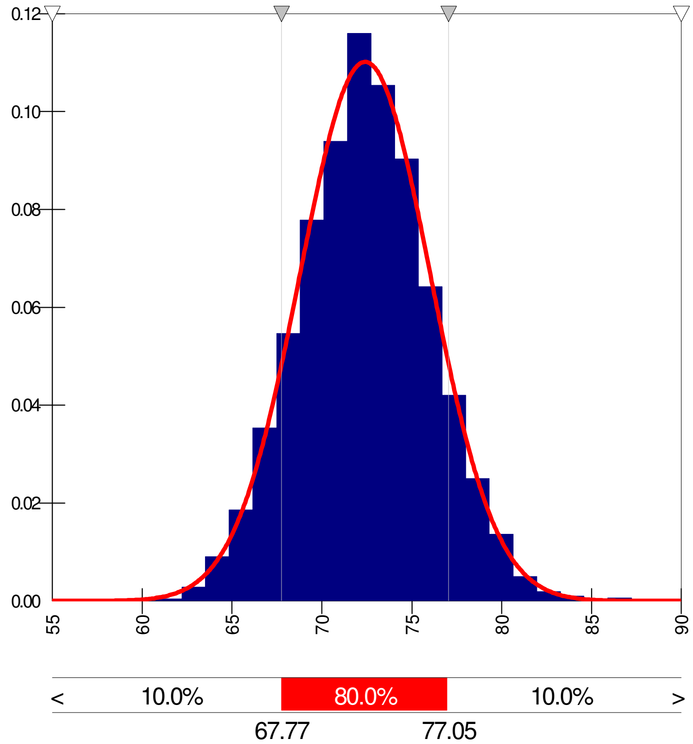

Figure 49: Fast Reserve range of costs for 2010/11

3.4.5 Response

377 The cost incurred for the availability, usage and to position generation and consuming units into a frequency responsive mode, in order to manage instantaneous change in the frequency.

378 This component depends on Power Price, NIV, Wholesale to BM Price multipliers, Demand, Wind capacity, Response BOA volumes and prices, response providers, mandatory response volumes and prices, other response and nuclear availability.

379 The central forecast for 2010/11 is £197.1 million, with an expected (mean) value of £202.5 million and 80% probability of being between £194.7m and £210.4m.

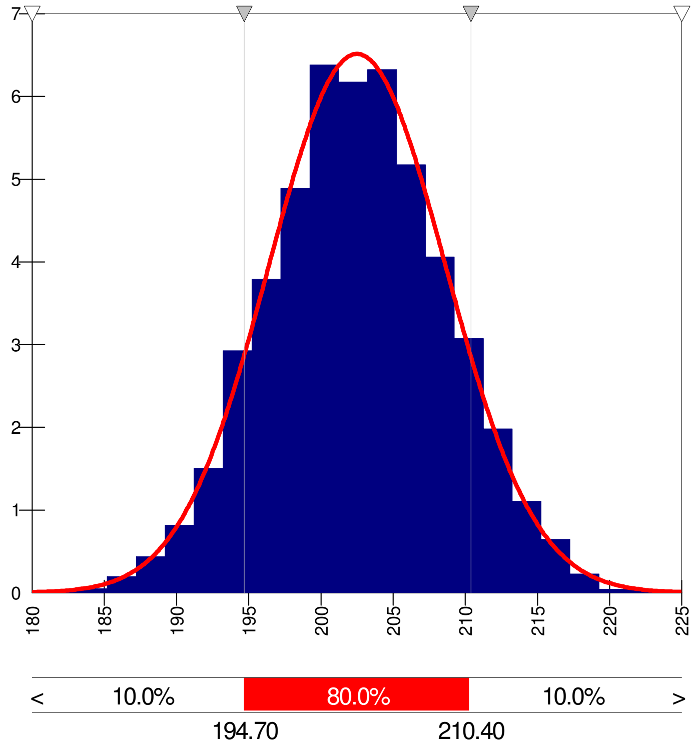

Figure 50: Response range of costs for 2010/11

3.4.6 Net Imbalance Adjustment (NIA)

380 The central forecast for NIA, based on the current formulation as stated in section 2.2.2, is -£299.7 million, with an expected (mean) value of -£303.5 million and 80% probability of being between -£342.0m and -£265.5m. In section 4 we discuss potential improvements to NIA.

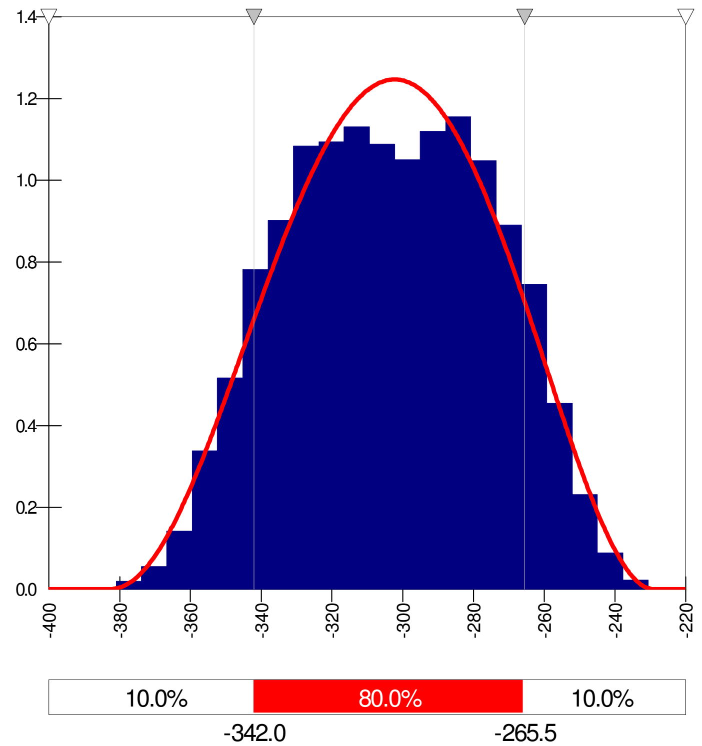

Figure 51: NIA forecast range for 2010/11

3.4.7 Reactive

381 The cost incurred for the despatch of reactive power from generating units.

382 This component depends on Power Price, Demand and RPI.

383 The central forecast for 2010/11 is £46.2 million (same as the expected (mean) value) and 80% probability of being between £42.3m and £50.1m.

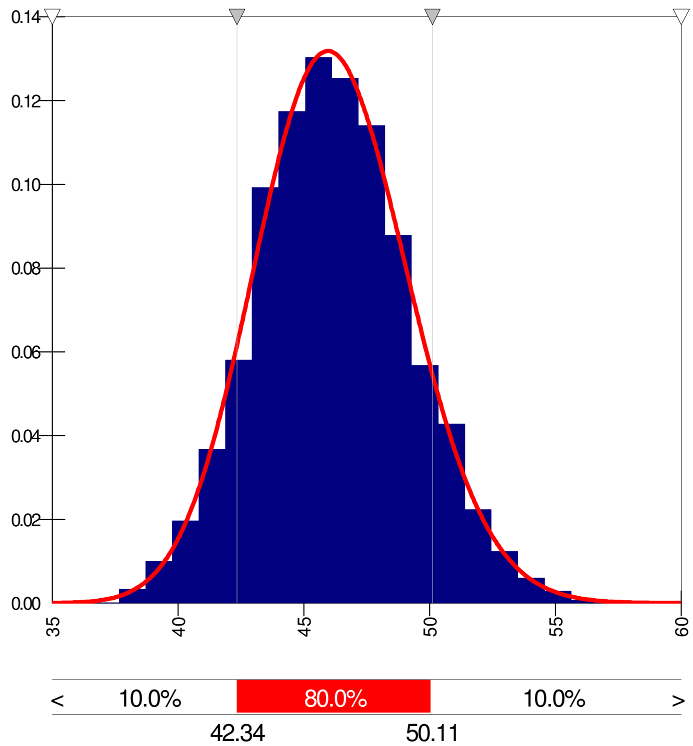

Figure 52: Reactive range of costs for 2010/11

3.4.7.1 Reactive Incentive Adjustment (RIA) factor

384 In section 4.7.2. we discuss the merits of a Reactive Incentive Adjustment factor, this section focuses on the impact to the BSIS forecast of such an adjustment. The proposed adjustment factor for the reduction of National Grid’s exposure to changes in power price and RPI affecting Reactive costs has a central forecast for 2010/11 of -£46.2 million (same as the expected (mean) value) and 80% probability of being between -£50.2m and -£42.3m.

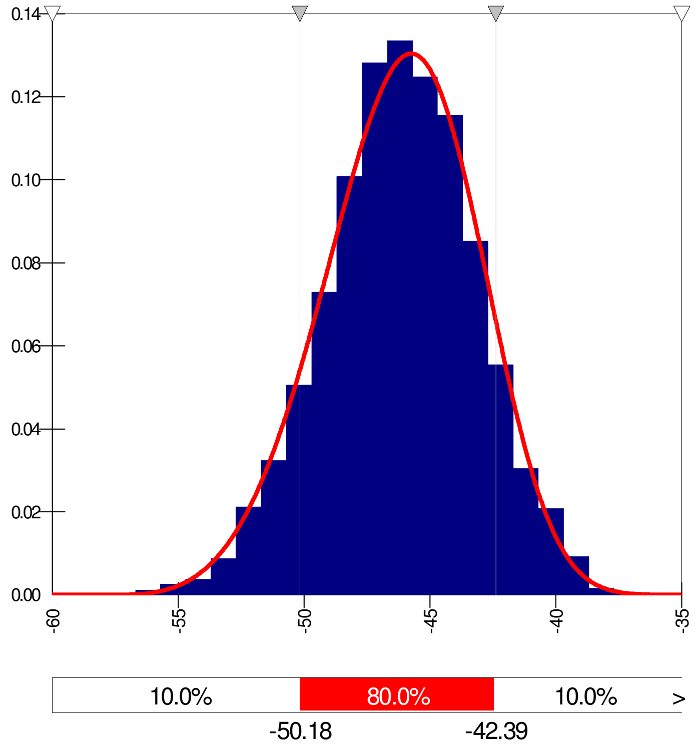

Figure 53: RIA forecast range for 2010/11

385 Taking the combined forecast values of Reactive plus RIA throughout the range of wholesale prices and RPI values produces the distribution shown below. This gives a net reactive power target cost for 2010/11 is £0 with 80% probability of being between -£0.8m and £0.8m.

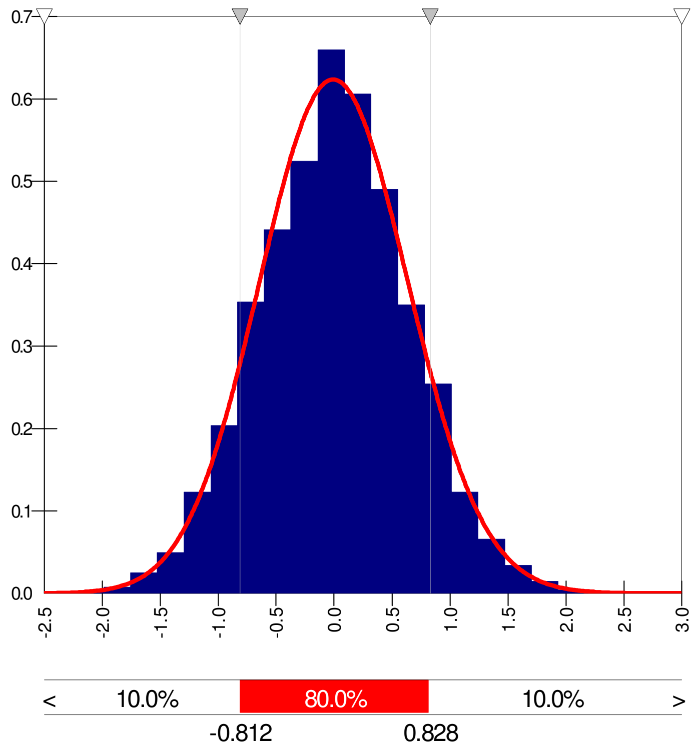

Figure 54: Net Reactive target cost range for 2010/11

3.4.8 Other

386 Black Start, based on contracted position, has a forecast cost of £23.1m

387 Unclassified BM and BM+BS general, based on historic ratios, have a central forecast of £30.2m with 80% probability of being between £27.9m and £33.3m. These values are in addition to the previously quoted Black Start number.

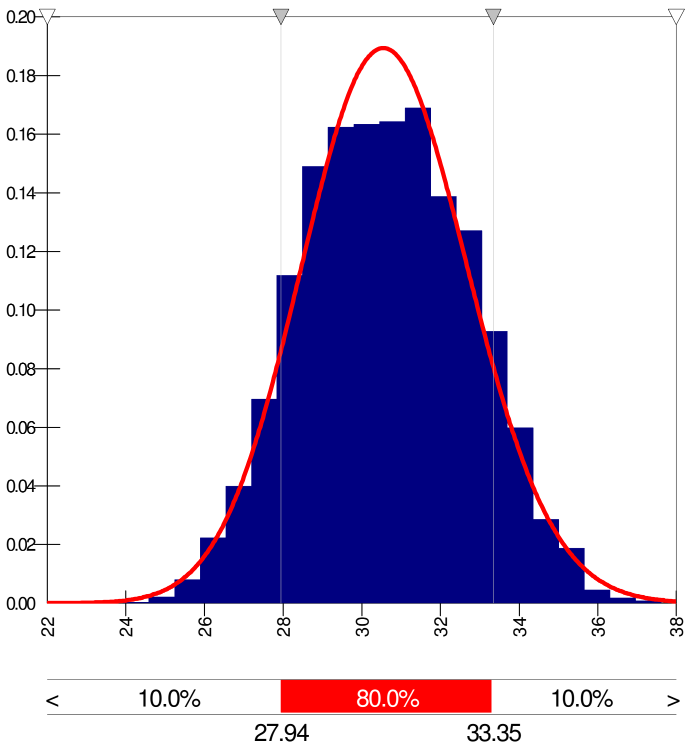

Figure 55: Other BM range of costs for 2010/11

3.4.9 Total Energy Components

Component	Central view	Expected (mean)	10th percentile	90th percentile
Energy Imbalance	26.4	32.5	-6.3	72.1
Margin	367.2	366.0	334.4	398.7
Footroom	22.5	22.7	18.0	27.2
Fast Reserve	72.4	72.4	67.8	77.1
Response	197.1	202.5	194.7	210.4
BM+BS General and Unclassified BM	30.2	30.6	27.9	33.3
Total Energy Related components (without NIA)	715.9	726.7	662.3	792.8
NIA	-299.7	-303.5	-342.0	-265.5
Total Energy Related components (with NIA)	416.1	423.1	385.2	462.2
Black Start	23.1			
Reactive	46.2	46.2	42.3	50.1
Total IBC less Constraints	485.4	492.4	454.6	531.5
Reactive Incentive Adjustment	-46.2	-46.2	-50.2	-42.4
Reactive Adjusted IBC less constraints	439.2	446.2	408.1	485.2

3.4.10 Summary of changes in costs from latest view

388 National Grid produces quarterly re-forecasts of costs for the current year (2009/10) incentive scheme, the latest one having been produced in September. This latest view includes outturns from April 2009 to August 2009 and our latest forecast from September 2009 to March 2010.

389 The following “waterfall” diagrams will illustrate the steps driving the forecast costs from their current level to the numbers presented above. These charts do not include constraint costs.

3.4.10.1 Total Energy Related components

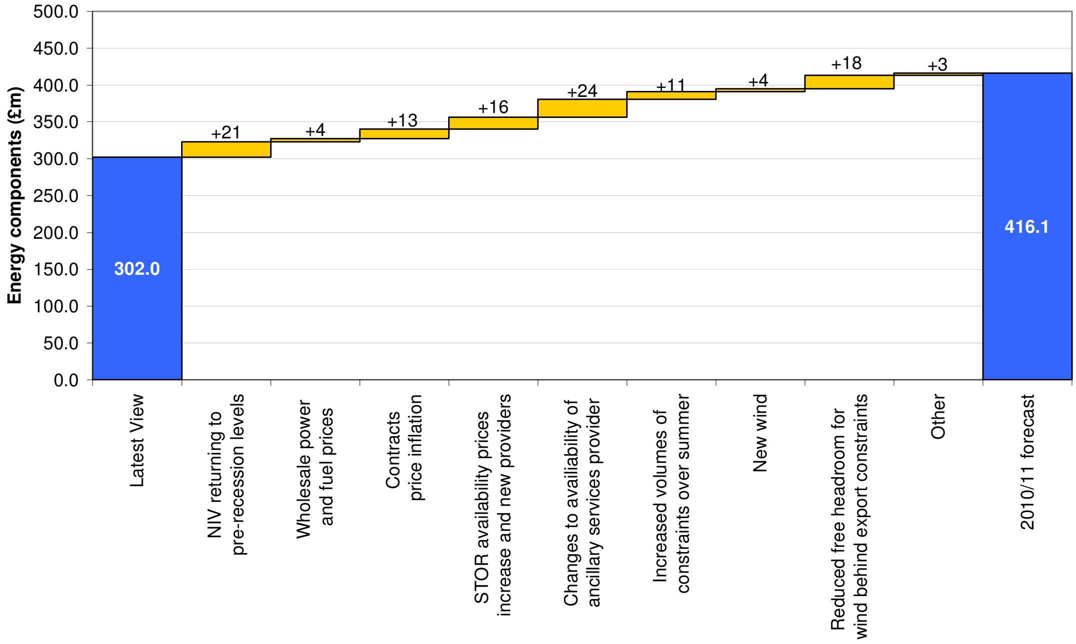

Figure 56: Waterfall diagram for Energy components

3.4.10.2 Total IBC less Constraints

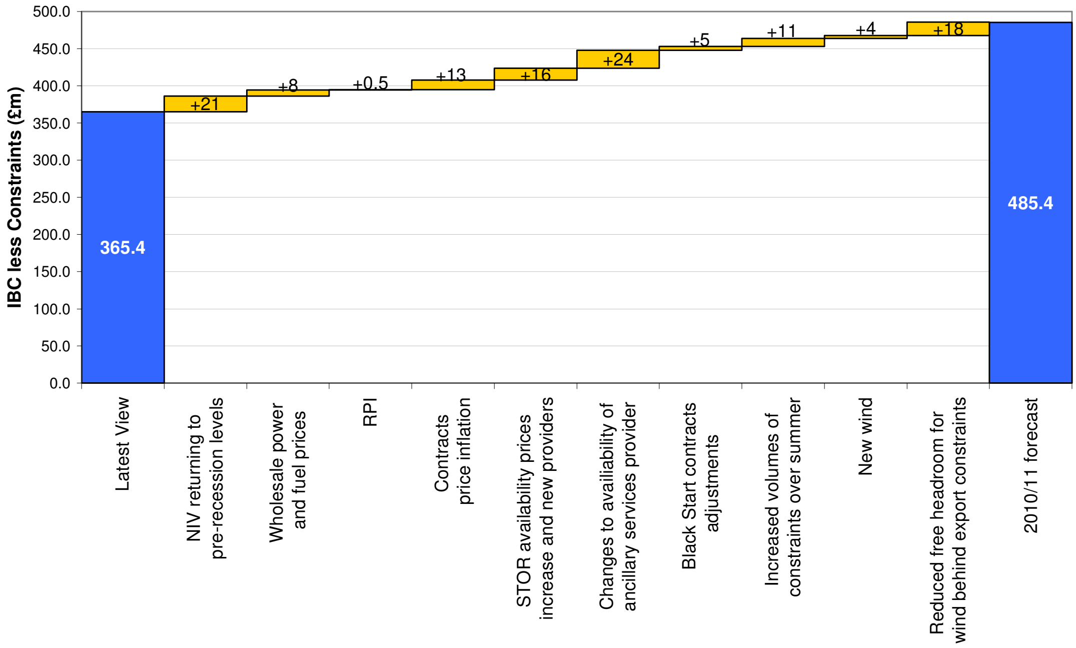

Figure 57: Waterfall diagram for IBC less Constraints

Question 26: Do you have any further comments regarding this forecast or the assumptions made in its development?

3.5 Constraints forecast Assumptions

390 As discussed in section 2.8 constraint costs are driven by

- The volume of actions required
- The price of those actions

391 Constraint volumes are closely related to the outage plan and pattern of generation experienced on the network versus the installed transmission capacity. The pricing of actions required to resolve the constraint is then linked to the levels of reserve present on the system at that time and the price of creating additional margin.

3.5.1 Volume Assumptions:

392 The volume of actions required to manage a constraint is dependent on

- Generation
- Demand
- Direction and volume of flows on interconnectors
- System Capacity
- Fault Outages
- System to Generation Intertrip Schemes

3.5.1.1 Generation

3.5.1.1.1 Availability and running patterns of conventional flexible generation

393 As described in section 2.8.1.1, the volume of generation which has self dispatched behind a constraint boundary is a major driver of the volume of actions required to resolve transmission system constraints.

394 Generators provide National Grid with their forecast outage plan as part of their Grid Code obligations (Operating Code 2), known as OC2 data. These data submissions on outage programme are used to form the basis of the forecast of the volume of constraint actions as it is the most up to date data source available.

395 To reflect that all generators will not generate at all times when not on outage, '@Risk Monte Carlo' simulations are used to predict generation output. Monte Carlo simulations are carried out on historic output to predict generation availability.

396 Historic running patterns since BETTA Go-Live are considered by the Monte Carlo simulations. Where the constraint volume is primarily dependant on running regimes of coal plant, data since January 2008 is used to reflect the impact of LCPD. Where constraint volumes were resolved primarily by contracting generation to export specific volumes onto the system, that years data is not used. This is to prevent reduced

or increased volumes due to contracts in place polluting the predicted output of generation.

3.5.1.1.2 Nuclear availability

397 As discussed in section 3.2.3, improved availability from nuclear generators is expected to continue as seen in recent months following significant refurbishment outages during 2008.

398 When preparing the constraint forecasts, this results in raw OC2 submissions being used for nuclear generations, without application of an availability assumption derived from @Risk Monte Carlo simulations.

3.5.1.1.3 Wind Generation

399 The volume of wind generation due to connect in future has been discussed in section 3.2.2. The constraint model uses connection dates where available and assumes that load factor remains consistent with load factors observed historically.

400 The Scotland constraints model considers wind farms to have a load factor in each sample consistent with the historical load factor for the time of year. Being a Monte Carlo simulation the distribution of wind output around this value can also be considered.

401 The volume of additional wind generation connecting behind the constraint boundary increases the volume of actions required to resolve the constraint. This increase in volume and associated cost is not wind generation specific but rather due to an increased volume of generation behind an active constraint boundary.

402 There may be times of low conventional generation output and high wind output which does not result in a requirement to constrain generation to manage flows on a constraint boundary. This interdependence of generation output is modelled by historic distributions of generation load factor – both conventional and wind – which are then sampled by Monte-Carlo simulation.

403 Increased running of inflexible generation at periods of low demand, potentially displacing conventional plant, is expected to increase the cost of constraint actions at such times. An additional model has been developed to explore this scenario. Reduced output from conventional generation, limiting value of system to generator intertrip scheme and available actions to manage the constraint, will lead to a requirement to reduce wind generation output at high cost. This model assumes that all other available actions are taken prior to the reduction of wind generation. The price used in the forecast to bid wind back is based on an approximation of wind bids seen in the BM historically.

404 The volume of wind generation connecting in 2010/11 will result in new constraint boundaries, internal to Scotland. Thus when the constraint is active due to the volume of wind, actions must be taken to reduce the output of some of that generation.

3.5.1.2 Demand

405 The demand forecast used in the constraint models is from the same data set used in the Energy forecasting model. The assumptions used in the production of this forecast are as described in section 3.2.5.

3.5.1.3 Direction and volume of flows on interconnectors

406 The forecast for flows on both the IFA (England-France) and BritNed (England – Holland) interconnectors is based on current price spreads between France and the UK and Holland and the UK.

407 Price spreads for traded peaks (07:00 to 19:00) between France and the UK indicate that significant volume of power will flow to France on the IFA over the summer and that the exports to France of 2000MW will also be seen through winter. Power is expected to flow to the UK over night.

408 The constraint forecast assumes that BritNed will commission in early 2011. The price spread indicates that this interconnector will also export over the peak periods.

409 As the price spreads indicate that power on both interconnectors will flows in the same directions (to or from the UK), no wheeling[49] of power through the GB transmission system has been assumed.

410 The forecast spreads derived show a premium to France for 2010/11 over the traded Peaks (07:00 to 19:00). This premium is modest for Q1 (~£4/MWh) but would represent a significant export to France. However, considering Q2, Q3 and Q4, the premium increases to a level which would definitely indicate full export to France on the IFA of 2000MW. The exception to this would be on high demand days in the UK as counterparties would not want to be exposed to triad risk and would look to maintain a float position over the darkness peak demand period.

411 The spreads for the Baseload product are slightly in favour of the UK for Q2 and Q3 which would lead to a flow to the UK on the traded Off-Peaks (19:00 to 07:00). Historically, this flow has tended to be greater for the Overnights (23:00 to 07:00) than for EFA6 (19:00 to 23:00). For the later quarters, despite the Baseload spreads being negative, the Off-Peaks would still be expected to flow to the UK as the weight of the premium to France is contained in the Peak product.

[49] One interconnector to continental Europe is importing and the other interconnector is exporting

412 Comparing the forecast spreads used for this year's BSIS with the out-turn spreads and updated forecasts has shown that across the summer period the market moved from a small premium to France to a small premium to the UK across the Peak product. The Baseload spreads which were forecast to show healthy flows to the UK actually narrowed significantly. However the forecast winter spreads for the Peak contracts, which showed large premiums to France, have actually moved further towards France. Baseload spreads have also moved further to France to such an extent that the Off-Peaks would also flow to the continent.

413 Historically, the spread between the prices in the Single Electricity Market[50] (SEM) and the UK market has not served as an indicator of power flow on the Moyle (Scotland – Northern Ireland) Interconnector. As such, it is modelled as a regular generator, i.e. Monte Carlo simulations are carried out on historic output to predict flows on this interconnector.

3.5.1.4 System Capacity

414 As described in section 2.8.1.5, the transmission system is generally constructed such that there is sufficient capacity for all the connected generation to reach the wider market. There are a number of intact system restrictions e.g. boundaries on which constraints can occur with all circuits in service.

415 System capacity is reduced due to outages required for new connections, system reinforcement asset replacement, maintenance and fault outages. There are a number of outages planned for 2010/11 in Scotland and England and Wales which are forecast to result in significant constraint volumes.

416 When developing the outage programme, transmission system outages are placed against generation outages submitted in OC2 data to limit the volume of constraint actions required.

417 The forecast is based on the outage programme, as known, and OC2 generation submissions at this time. Both are subject to change; transmission outages may change until 'Plan Freeze' at week 49 and are also subject to within year changes. Generation outages may change up to real time as their respective owners develop their own plans.

418 The volume of constraints for the forecast is based on power system analysis where available and operational experience of historical levels. The power system analysis calculates the constraint limit for the transmission system outage programme as known against the generation background from OC2 data. The constraint volumes may be further optimised as additional solutions are identified. Equally, some additional system issues may be identified that increase volumes.

[50] The wholesale electricity market operating in Republic of Ireland and Northern Ireland

3.5.1.5 England & Wales Outages for 2010/11

419 The most significant outages in England and Wales are system reinforcement works, required due to new generation connections. Outages required for asset replacement and for maintenance have been placed such that constraint volumes are not exacerbated.

420 The outages resulting in the greatest volume of constraint is in the South East and is required to facilitate the connection of new generation planned for the Thames Estuary. This area of the transmission system is shown in the diagram below. Outages are required to decommission a 275kV circuit, the limiting factor for system access in the area, and commission a new 400kV double circuit route. Additionally, further outages are required on major north-south transmission circuits to facilitate the connection of new generation. This is detailed below.

3.5.1.5.1 Thames Estuary

421 A simplistic view of the system around the Thames Estuary is shown below. Estuary generation is shown in red, a total of 6250MW of generation in a group with four routes to the rest of the system. The prevailing direction of power flow is indicated by the red arrows.

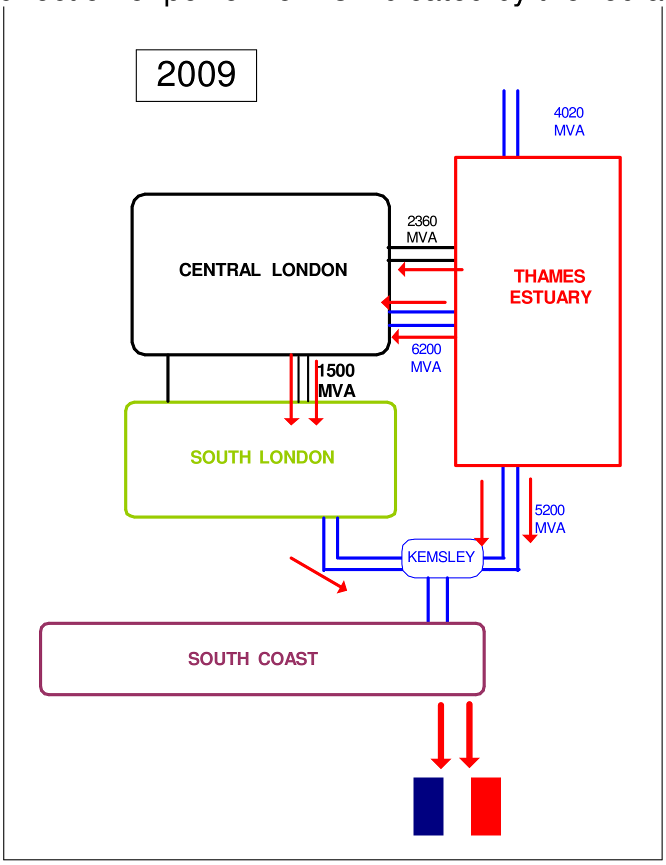

Figure 58: Diagrammatic Representation of South-East England

422 This area of the system is one which is heavily congested and where under intact system conditions and exports on the IFA, constraint limits are close to being active continually. There is a significant amount of generation connecting in the area over the coming years and a lengthy programme of works is in progress to complete required reinforcement works to secure the connection of this generation. The connection of the new Grain CCGT station will see this boundary change from a boundary with no spare capacity to a boundary with insufficient capacity to allow all generation access to the system at times that the IFA is exporting. Grain CCGT increases generation in a congested area of the system and the running pattern expected of a new gas generation unit will result in increased flows out of the group.

423 A significant volume of new generation is due to connect in this area over the coming years. In order to facilitate these connections, a major programme of construction work is underway and due to continue until 2013 including both local and wider system reinforcement and replacement of aging assets. Key works include the establishment of a new transmission circuit from Littlebrook to Tilbury and the up-rating of existing 275kV circuits between Barking and Littlebrook for operation at 400kV. This work requires work on transformers at West Thurrock and Littlebrook. This increase in operating voltage will increase the thermal rating of the equipment but also serve to improve the voltage profile in the South East, removing the requirement for additional reactive equipment to be installed in the area.

424 The most significant outages required in 2010/11 are to decommission the Littlebrook – Barking circuits and the commissioning of a double circuit route between Tilbury and Littlebrook. The Littlebrook – Barking circuits currently operate at 275kV. The new Littlebrook - Tilbury circuits will operate at 400kV.

425 The volume of constraint is heavily dependant on the direction and volume of power transfer on the IFA. Working with the Transmission Owner, an alternative work programme has already been developed to reduce the constraint volume significantly. The planned outages are part of the TO strategy to reinforce the system in this area in view of the volume of generation looking to connect.

3.5.1.5.2 Grendon - Staythorpe

426 A long outage is required on the Grendon – Staythorpe circuit during 2010 to increase the rating of the circuit (the work was commenced in 2009) as part of the infrastructure reinforcements for the Staythorpe and West Burton B generation schemes.

427 The works planned on the circuit is to replace the overhead line. Due to the length of the circuit, this has taken place over two years with work commencing in 2009/10. The following diagram shows a simplified

overview of the outage and the effective generation to resolve the constraint.

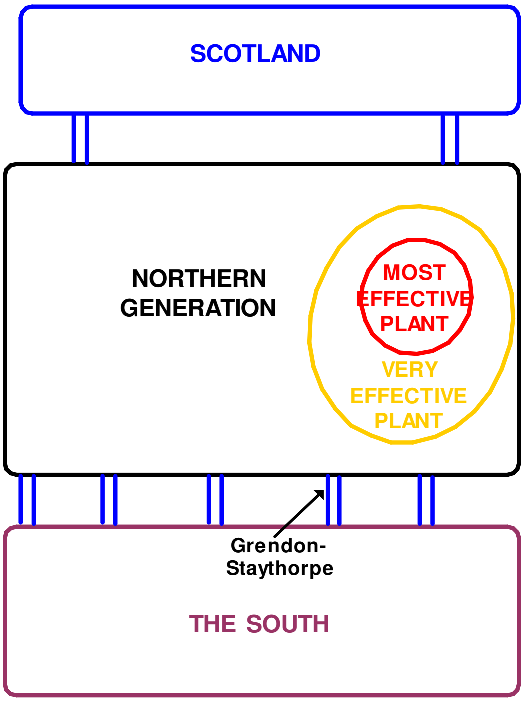

Figure 59: Diagrammatic Representation of the GB Transmission Network

428 Generation with the greatest impact on circuit loadings affected by the outage is shown in the red and yellow zones in Figure 59 above. While a reduction of 100MW of generation in the north beyond these groups will only reduce the loading by 10MVA, the volume of generation is such that the impact of outages could be significant.

3.5.1.5.3 Other Significant Outages in England and Wales:

429 The most significant works planned for the south of the transmission system are

- Those in the Thames Estuary region described above
- Connection of a new generator and connection of additional rail track supplies require long outages on two separate constraint boundaries.

Asset replacement requirements, including refurbishment of circuit breakers to extend the asset life, drive the remainder of the major outages in the south of England.

430 The outage programme for the north of England is driven by reinforcement of new generation connections, asset replacement and reinforcements in the north east to compliment the TIRG works completed in Scotland.

3.5.1.6 Scottish Outages for 2010/11

431 Outages continue in Scotland to complete required TIRG[51] works. The outages required in 2010/11 reduce the transfer which can be secured across the Cheviot boundary from the 2009/10 limit by 400MW. Internal outages are required for asset replacement work. Some reinforcement works have been advanced to be completed in 2010/11.

432 The diagram below indicates the location of major generation and planned outages within Scotland for 2010/11. Red arrows indicate the typical direction of power flow, black arrows indicate key outages. Blue lines show 400kV circuits, Black 275kV and Orange 132kV.

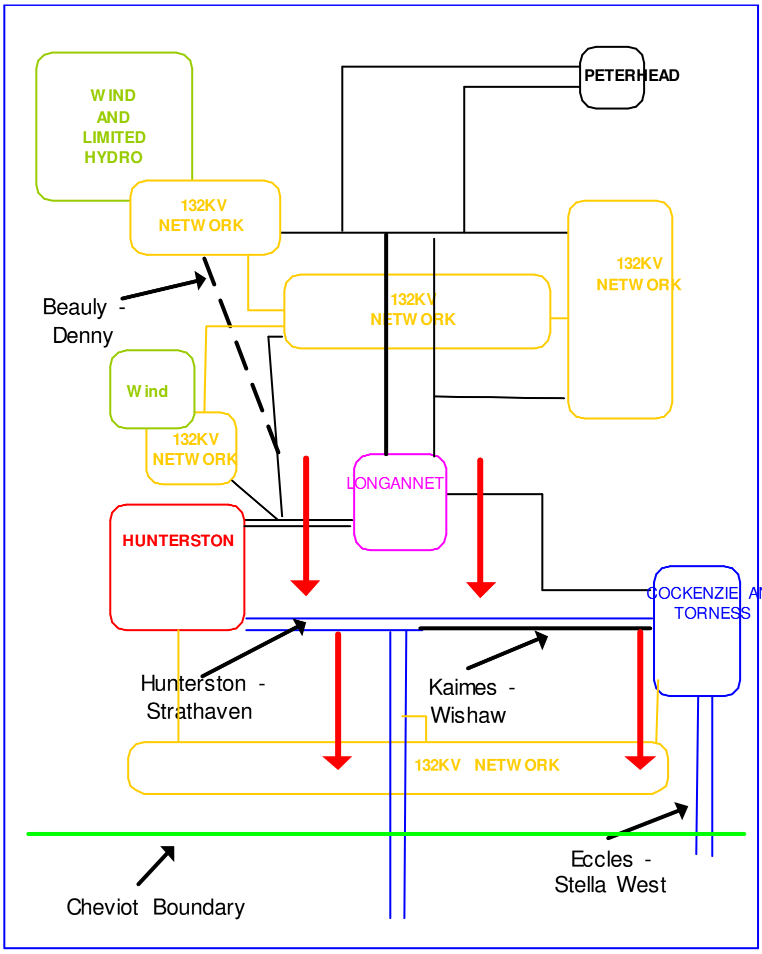

Figure 60: Diagrammatic Representation of the Scottish Transmission Network

[51] Transmission Investment for Renewable Generation, aimed at increasing the capacity of the transmission system in order to absorb the expected increase in renewable generation in Scotland

3.5.1.6.1 Power flows on the Scottish transmission system:

433 The power flows within the Scottish system are primarily from North to South, flowing into England via two 400kV double circuits, the Cheviot[52] boundary. The constraint limit across this boundary can be due to both thermal and stability issues. Generation to system intertrip schemes and contracts with generation units, in addition to actions in the BM, are used to resolve this constraint boundary. The capability of this boundary relative to the generation behind it is such that there is potential for an active constraint when the boundary is in intact (all circuits in service). This constraint is exacerbated when outages are taken on any of these circuits. Although predominantly this constraint impacts power exports from Scotland, depending on the availability of generation within Scotland, including renewables, there are times when this can be an import constraint.

434 Interaction between generators at different locations within Scotland can result in significant internal system constraints which must also be managed. For example, if the total generation at a particular power station were constrained off, this might lead to active internal constraints within Scotland. This interaction is considered when developing an optimal solution to manage both internal and Cheviot boundary constraint costs.

3.5.1.6.2 Outages in South Scotland:

435 The 2010/11 outage programme has a long outage on the Eccles – Stella West as part of the TIRG works. This outage starts in week 14 and will continue until clock change at week 44. This outage reduces the transfer which can be secured across the SCOTEX boundary from the limit in place in 2009/10.

436 A long outage is required on the Kaimes - Wishaw circuit (shown in the diagrams) which is required to replace the earth wire and optical fibre links. This outage limits the potential power flow which can be secured from East to West.

437 An outage is planned for the 400kV route from Hunterston to Strathaven. The conductor of this overhead line is to be replaced and is part of Asset Replacement work.

3.5.1.6.3 Outage in North Scotland:

438 A decision has not been taken by the Scottish Administration regarding planning permissions for the Beauly – Denny overhead line as yet. As the major outages required for this circuit are not being taken in 2010/11 but will be required against a background of increased levels of generation, SHETL have advanced works to reinforce 275kV routes in

[52] This is also known as the B6 boundary

the area. Some work is required on the 132kV network in preparation of the Beauly – Denny line.

439 A long outage is planned on the Tealing - Westfield circuit to replace GA10 circuit breakers that are installed on this route. These must be removed from the system for safety reasons.

3.5.1.7 Fault outages

440 As discussed in section 2.8.1.6 faults resulting in damage to transmission system equipment require significant outages to allow safe return of the equipment to service. The impact of these outages cannot be mitigated in the same manner as planned outages.

441 The constraint forecast presented does not include any allowance for the impact of fault outages.

3.5.1.8 System to Generation Intertrip schemes

442 The forecast assumes that a system to generation tripping scheme is used as a post fault action where the required equipment is in place and where it would economic to use such a scheme.

443 The forecast assumes that CAP170 is not in place. Our current view is that CAP170 would reduce our forecast Cheviot constraint costs in 2010/11 by some £100 million.

444 Contract terms and prices for arming fees of intertrip schemes assumed in the forecast are not in place yet. Discussions are underway with a number of generators to agree terms from April 2010. The forecast assumes these discussions are successful. The forecast does not include any provision for fees paid in the event of a system to generation tripping scheme firing.

Question 27: Do you have any comments on the background and assumptions made in constructing the constraints volume forecast?

3.5.2 Price Assumptions

445 The cost of a constraint is made up of the price of actions to resolve the constraint, the price of actions to rebalance the energy position and the cost of replacing margin.

446 Generic bid and offer prices used to derive costs of resolving a constraint are taken from the Energy and Margin models. The Energy model also gives a view of when the market will be long or short so prices used reflect if the action to resolve the constraint acts in the direction of the market or against, capturing the impact of bidding off generation when the market is short in the cost forecast.

447 Historic trends are used to scale back the bid price for constraining off plant in Scotland received from the forecasted GB bids in the energy model to reflect the price of accepting bids on Scottish plant. From BETTA Go-live, the prices of Bids taken for constraints in Scotland were substantially lower than the average accepted Bid price across GB as a whole. From December 2005 the prices accepted to manage constraints in Scotland have risen steadily relative to the GB average, stabilising at current levels since June 2007. Bid prices in England and Wales taken for constraints were also lower than the overall GB average accepted Bid price, although these were closer to the GB average than those in Scotland. A shallow increase in Bid price for constraints in England and Wales relative to GB Bid prices has been observed since.

448 Due to Renewable Obligation Certificate (ROC) payments, reducing the output of conventional generation provides a more economic alternative to reducing the output of wind generation when balancing the transmission system. The price assumed in the constraint forecasting to reduce the output of a wind generator is -£450/MWh.

449 There are a number of wind generation BM Units (BMU) that were not actively participating in the BM. Bids were set at -£99999/MWh, the maximum level permitted. As detailed in section 2.9.2, following discussions with providers and the raising of the issue at various forums, the bid pricing from wind generation has reduced to a range of -£300/MWh to -£800/MWh. The -£450/MWh used an approximation of the average bid prices for wind in the BM. This reduced range is still high and a large number of wind BM units are posting long notice time to vary their output, meaning they cannot be accessed in operational timescales. We will continue to work with the industry to improve wind participation in the BM.

450 The forecast uses four scenarios to calculate the cost of resolving any constraint which capture the interaction of prices of actions with market conditions

- Margin long/Energy long
- Margin long/ Energy Short
- Margin short/energy long
- Margin short/energy short

The percentage of time spend under each scenario is taken from the Energy model.

451 The increase in power price and corresponding increase in margin price has increased the constraint resolution price as it calculated the price to resolve the constraint, the price to rebalance energy and the price to replace margin.

452 Replacement costs used for constraints active over night are different to those used in the models considering the peak trading periods. This is to capture the assumption that we are not margin short over night. At present a simplistic view is assumed, that overnight we will be energy short for 50% and energy long for 50% of the time.

Question 28: Do you have any comments to make regarding the assumptions made in constructing the constraints price forecast?

3.6 Constraint forecast

3.6.1 Scotland

453 The costs of constraining units behind the derogated non-compliant Cheviot boundary (between Scotland and England) are currently forecast for 2010/11 at £180m. The costs of resolving constrains within Scotland are currently forecast for 2010/11 at £110m.

454 The increase in the forecast from the 2009/10 scheme forecast (£209m) is driven by increases in the following areas

- New generation connecting behind the constraint boundary (£30m)
- Actions to reduce the output of wind generation (£13m)
- Effect of increased margin prices (£9m)
- Reduced constraint limit due to the 2010/11 outage plan (£29m)

455 The total cost of constraints in Scotland has a central forecast for 2010/11 of £290m, with 80% probability of being between £221m and £367m.

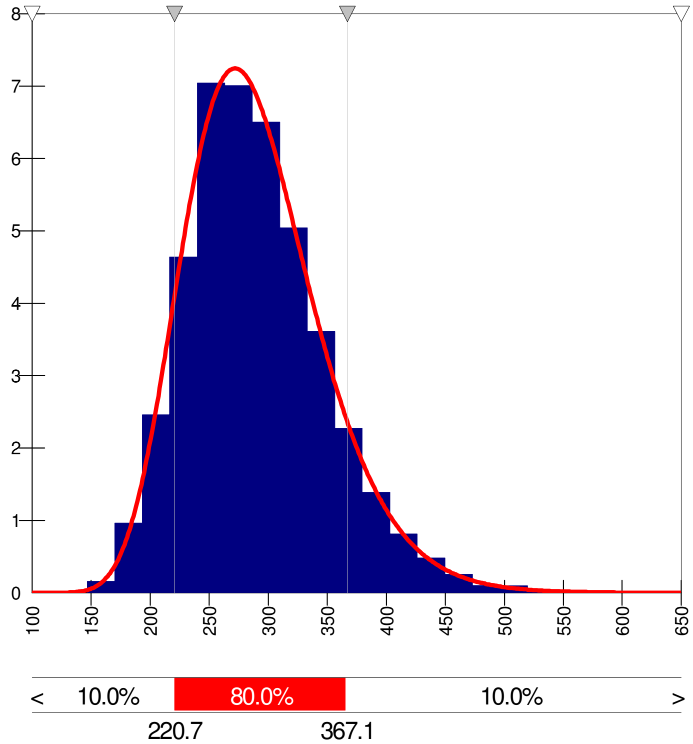

Figure 61: Scotland constraints range of costs for 2010/11

3.6.2 England and Wales

456 The cost of resolving the main constraint in the Thames Estuary is currently forecast for 2010/11 at £100m, with an expected (mean) value of £108m and 80% probability of being between £49m and £175m. The volume of constraint caused by this outage is 1.3TWh, comparable to the total volume of constraint in England and Wales the past.

457 The cost of resolving the constraints arising from the outage at Grendon – Staythorpe is currently forecast for 2010/11 at £31m (same as the expected (mean) value) and 80% probability of being between £20m and £43m.

458 The cost of resolving all other constraints in England and Wales is currently forecast for 2010/11 at £56m (same as the expected (mean) value) and 80% probability of being between £49m and £62m.

459 The total cost of constraints in England and Wales is currently forecast for 2010/11 at £187m, with an expected (mean) value of £195m and 80% probability of being between £137m and £262m.

460 The increase in the forecast from 2009/10 (£50m) is driven by increases in both prices and volumes. The increase in power price and margin price (sections 3.3.1 and 3.3.5) has increased the constraint resolution price by approximately 20%.

- Grendon – Staythorpe costs increase by £10m. The increase in margin and power prices account for £8.5m of this increase. The remaining £1.5m is due to new generation connections.

- Other E&W outages (excluding Thames Estuary) costs increase by £27m. £11m of this increase is due to price increases. The outage programme as discussed for 2010/11 and impact on constraint boundaries causes an increase of £16m.

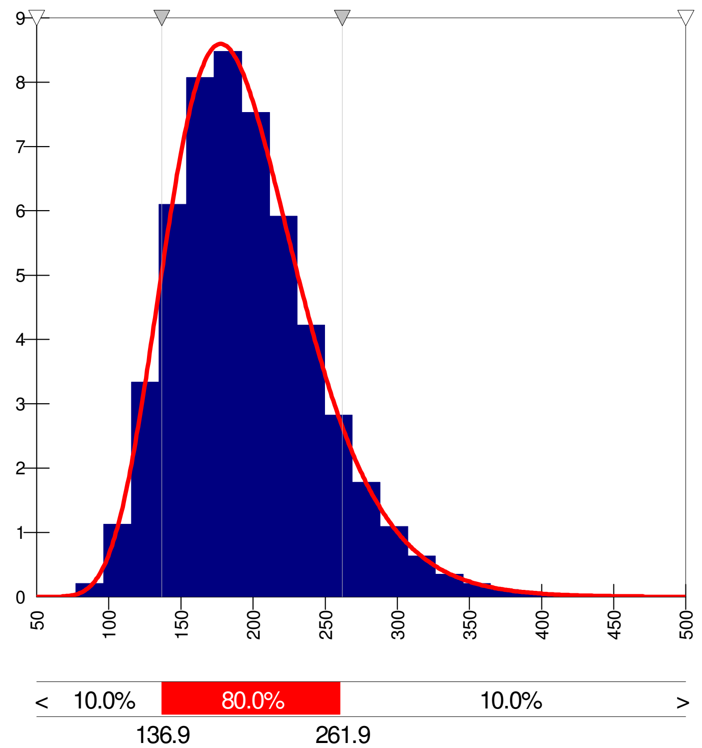

Figure 62: England & Wales constraints range of costs for 2010/11

3.6.3 Total Constraint Forecast

Component	Central view	Expected (mean)	10th percentile	90th percentile
Constraints Scotland	290.0	290.0	220.7	367.1
Constraints England & Wales	187.0	195.0	136.9	261.9
Total Constraints	477.0	485.5	387.6	594.2

3.7 Overall Forecast for 2010/11

461 The overall BSUoS forecast for 2010/11 is summarised in the table below:

Component	Central view	Expected (mean)	10th percentile	90th percentile
Total Energy Related components (without NIA)	715.9	726.7	662.3	792.8
Black Start	23.1			
Reactive	46.2	46.2	42.3	50.1
Total Constraints	477.0	485.5	387.6	594.2
Total External BSUoS	1262.2	1281.0	1137.8	1431.8
NIA	-299.7	-303.5	-342.0	-265.5
Total IBC	962.5	977.5	861.2	1100.4
Reactive Incentive Adjustment	-46.2	-46.2	-50.2	-42.4
Total RAIBC	916.3	931.3	815.7	1053.9

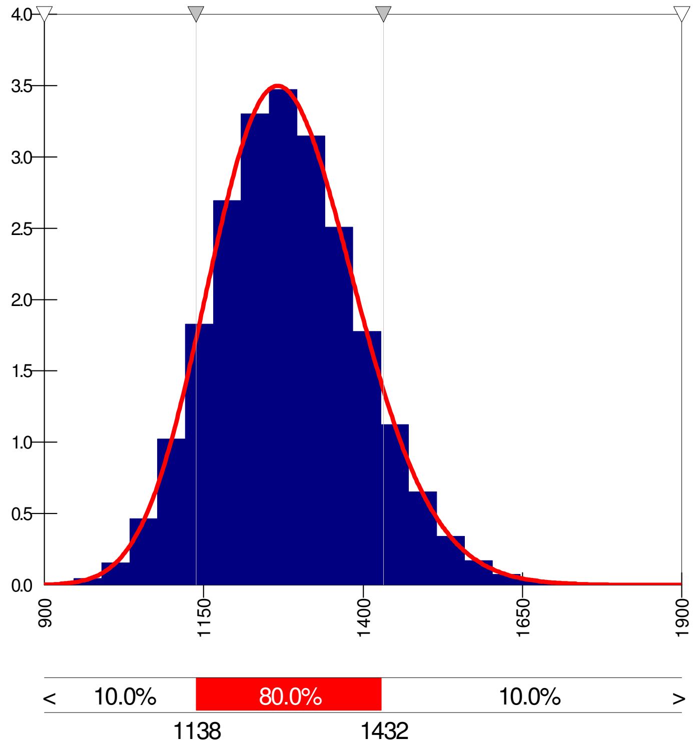

Figure 63: External BSUoS forecast range for 2010/11

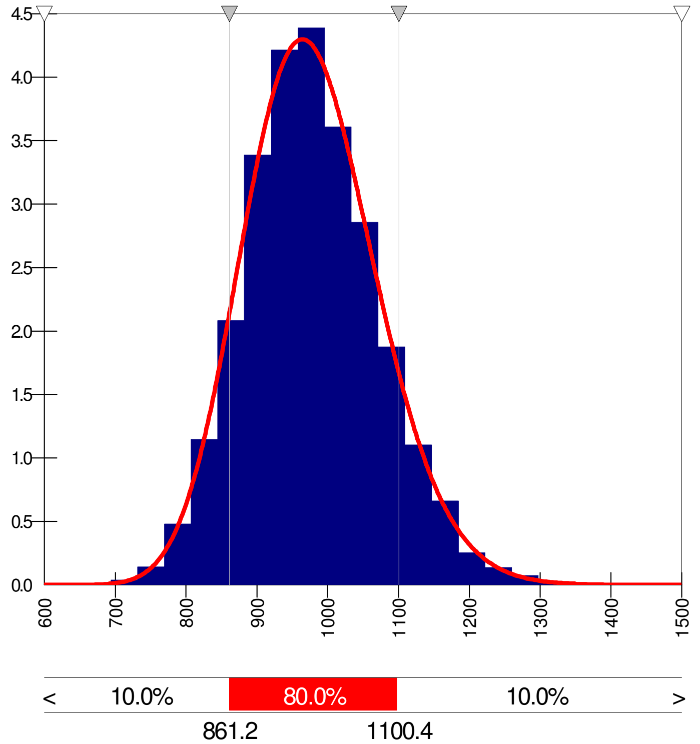

Figure 64: Total IBC forecast range for 2010/11

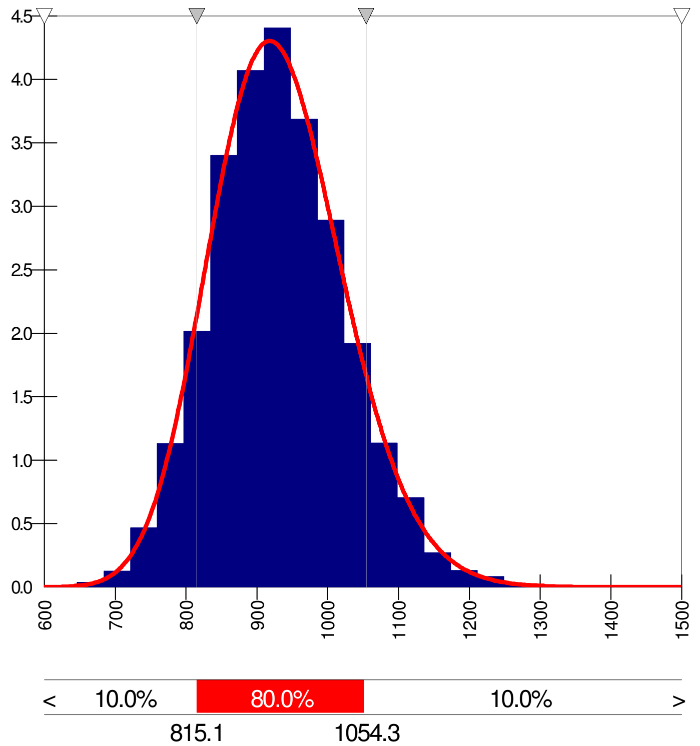

Figure 65: Total RAIBC forecast range for 2010/11

3.8 Forecast methodology for Year 2

462 Section 4 considers multi-year incentive schemes, in order to move to multi-year incentive schemes a forecast is required. This section sets out the forecast of the energy components for the second year of a possible two-year incentive scheme in line with the proposals discussed in section 4. As no additional information is available on the second year that is not also applicable to the first year, the forecast is based on the same set of assumptions as detailed in section 3.2 and 3.3.

463 The exceptions from the above are the assumptions based on external source, i.e. power price (forward price curve from Argus, carbon and exchange rates from Bloomberg) and RPI (forecast from Expedia Business Strategy).

464 We have also included the expected connection of additional 200 MW of wind generation every month in the financial year 2011/12, and our current view of the contractual position for Black Start costs.

465 These are the forecast for 2011/12 of each component (in millions of Pounds Sterling):

Component	Central view	Expected (mean)	10th percentile	90th percentile
Energy Imbalance	29.8	36.6	-6.3	81.9
Margin	414.3	412.8	376.0	449.7
Footroom	23.6	23.7	18.8	28.5
Fast Reserve	77.0	77.0	71.8	82.2
Response	212.3	219.1	210.3	228.0
BM+BS General and Unclassified BM	33.3	33.3	30.8	36.9
Total Energy Related components (without NIA)	790.3	803.0	731.6	876.6
NIA	-338.7	-343.0	-387.1	-300.5
Total Energy Related components (with NIA)	451.6	460.0	417.7	502.4
Black Start	21.9			
Reactive	51.3	51.3	46.1	56.5
Total IBC less Constraints	524.8	533.2	490.1	575.7
Reactive Incentive Adjustment	-51.3	-51.3	-56.4	-46.2
Total RAIBC less Constraints	473.5	481.9	439.4	524.5

Question 29: Do you agree with the methodology used to forecast the second year of a two year scheme for all components except constraints?

Question 30: Do you have any suggestions for other factors that should be taken in to consideration for the second year?

3.8.1 Summary of changes in costs from 2010/11

466 As detailed above the forecast for the energy components of BSIS in 2011/12 is based on the same trend assumptions as per 2010/11 with updated power and carbon prices and additional wind connections included.

467 The following waterfall diagrams indicate the impact of these on the Energy Related components and in other areas (e.g. Reactive, Black Start, Transmission Losses), excluding constraints in both cases.

3.8.1.1 Total Energy Related components

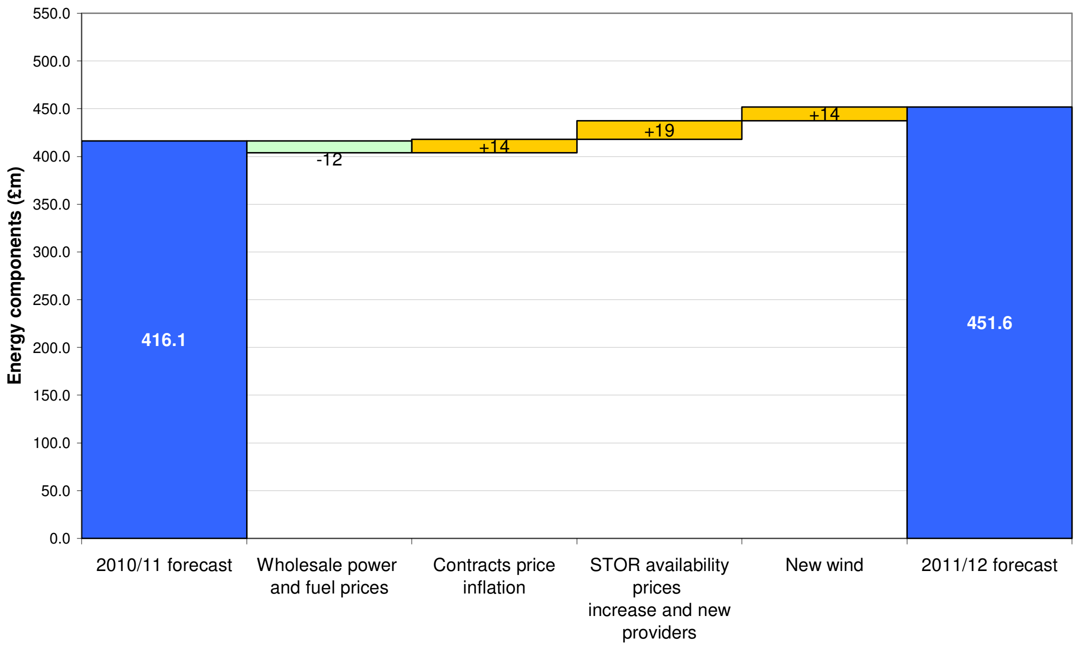

Figure 66: Energy components waterfall from 2010/11 to 2011/12

3.8.1.2 Total IBC less Constraints

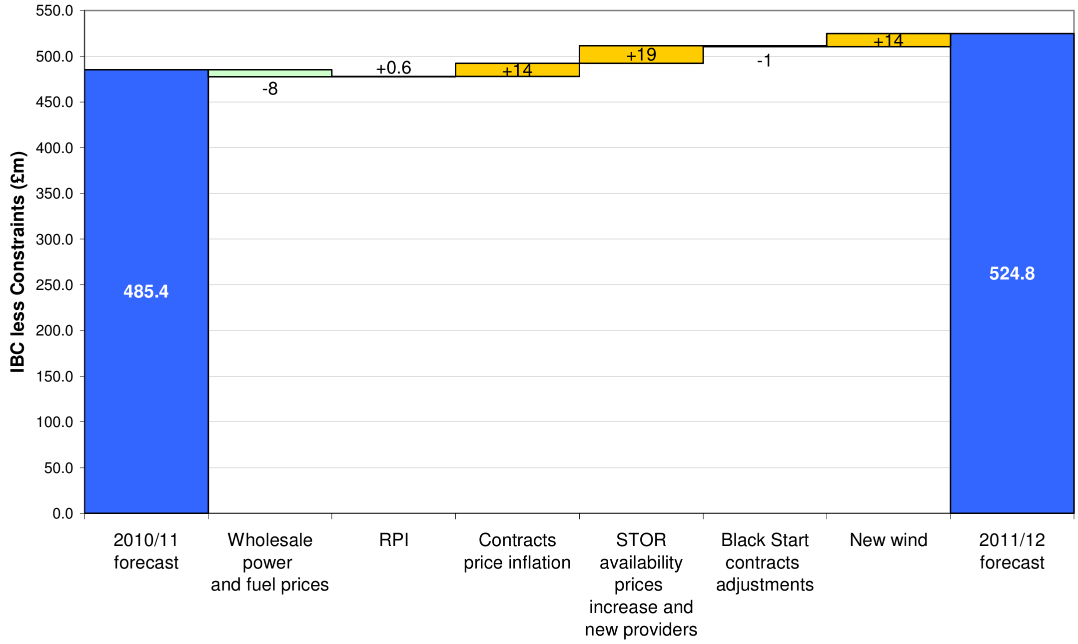

Figure 67: IBC less Constraints waterfall from 2010/11 to 2011/12

Section 4
Scheme Design

In this section we set out a high level overview of the current SO incentive scheme, the aims of incentive development for implementation in April 2010, feedback from the Mini consultations and an overview of the incentive options being proposed.

4.1 Introduction

468 As outlined in section 4.2, the main aims of the incentive design for the development of a scheme from April 2010 is the consideration of multi year schemes, the benefits of bundled / unbundled schemes and the introduction of appropriate adjustments.

469 In this section we outline the rationale for the development of the proposed schemes and provide incentive scheme options for consideration by the industry.

470 Further information on the current incentive arrangements are outlined in section 1.

4.2 Aims and objectives for incentive development

471 As discussed in Section 1 Ofgem has asked National Grid to lead on the development of initial proposals for the implementation of System Operator (SO) incentives commencing April 2010.

472 The main topics for consideration for the development of incentives from April 2010 were focused on:

- If it is appropriate to unbundle the balancing services cost components into separate schemes
- If there are appropriate external measures that can be used to adjust the cost components for drivers outside the control of National Grid
- If the implementation of multi year schemes is suitable for some or all of the components and whether there are benefits for such changes over and above the current arrangements

473 To explore the potential for the development of indexation, unbundling and longer term schemes, National Grid issued three ‘mini’ consultations in August and September[53] 2009. Responses to these consultations have been used in the development of these Initial Proposals. In

[53] http://www.nationalgrid.com/uk/Electricity/soincentives/docs/

addition, we have aimed to address a number of questions that were raised within the responses within this document.

4.4 Mini Consultation Feedback

474 From the three mini consultations published over the summer, there were a combined total of 18 responses.

475 In this section we look at the responses on the overall aims of the incentive development (e.g. multi-year schemes, unbundling and the development of adjustment methodologies). Where responses relate to specific cost component, these are covered in sections 4.5 and 4.6.

476 The three main themes within the mini consultations, and points for consideration for the incentive scheme design are:

- Development of a multi-year scheme
- Development of appropriate adjustment methodologies
- Unbundling of components

477 There was a mixed response from the industry regarding the development of longer term schemes. Of the 18 responses to the mini consultation, there was limited support for the principle of implementing multi-year schemes. Of those that did support the development and implementation of a multi-year scheme, the main benefits seen were:

- Benefits of longer term schemes in driving down costs
- Reduced administration burden

478 The majority of respondents stated that they believed the uncertainty in BSUoS costs was a major barrier to the development of longer term schemes. The main concerns raised were:

- Increased risk of Income Adjusting Events (IAEs)[54] being raised
- The case for implementing a longer term incentive had not been made within the mini consultations. In addition, one respondent stated that National Grid should be investing in long term cost reduction measures within the current scheme structure.
- The current scheme structure did not preclude the long term recovery of investment costs for cost reduction methods and therefore there was limited rationale for implementing a multi-year scheme.

479 Although it may not be appropriate for all cost components, National Grid believes that there are a number of benefits in the development and implementation of multi-year incentives. These will be further discussed in sections 4.5 and 4.6.

[54] The process where the incentive target is retrospectively adjusted to reflect significant changes in balancing costs for events that were not envisaged in the forecast e.g. impact of implementation of CAP047 – Competitive Process for Mandatory Frequency Response

480 These concerns are recognised within the consultation and which we believe can be addressed. We do not believe that the responses highlighted any issues with the development of a multi-year scheme that cannot be addressed. We discuss methods to address these concerns in section 4.6 below.

481 For example, one method of reducing the likelihood of an IAE is to develop and implement appropriate adjustments for the main cost drivers such as power price.

482 The development of appropriate adjustments was generally supported by the industry. There was a number of concerns raised on what form these adjustment factors should take:

- Certain adjustment methodologies may reduce the incentive on National Grid to manage costs
- Some forms of adjustment may result in National Grid not being incentivised to develop appropriate hedge mechanisms
- The indexation or adjustment should not be too complex and should be transparent in its methodology

483 Therefore we have developed the following adjustment methodologies for that aim to adjust for drivers outside of National Grid's control:

- Reactive default price indexation
- Current NIA methodology continues
    - Potential change to a daily NIA (based on experience of winter 2009/10)

484 These are discussed in more detail in section 4.7.

485 Although again there were mixed responses from the industry, the majority of respondents did not support the development of unbundled incentive schemes. National Grid believes that the development of unbundled schemes provides a number of benefits which are described in section 4.5. An unbundled scheme, providing clear focus on specific costs, ensures that variation in cost away from the agreed target are transparent and visible without the potential pollution from other areas. As such performance in each area is clear and can be addressed appropriately. In addition, implementation of unbundled schemes with appropriate sharing factors with caps and collars for each component would be a method of reducing the likelihood of IAEs.

486 It is our belief that to develop longer-term incentive schemes, it is necessary to consider the appropriateness of the unbundling of components and the further use of adjustments.

4.5 National Grid's Proposal for Implementing Unbundled Incentives

487 The current BSIS incentive is a fully bundled scheme that incentivises all cost components in a single pot. In developing our initial proposals, we have considered the benefits and drawbacks of an unbundled scheme and the consultation responses made.

488 Of the 18 responses to the mini consultations, there was limited support for the principle of unbundling of cost components into separate incentives. The main points raised were:

- Concern with the interaction of components, where different cost components have the same driver e.g. reactive power and transmission losses having the same driver of flows on the system
- Benefits of unbundling not fully stated
- Unbundling leads to a more complex set of incentives

489 Of the five respondents that did support the principle of unbundling, a number stated that further evidence of the benefits and how the costs would be unbundled was required and therefore may not be appropriate for implementation in 2010.

490 We believe that the benefits of a partially unbundled scheme would allow the development of appropriate incentives and the implementation of a longer term scheme for the majority of cost components.

491 Although unbundling will ultimately result in increased governance and complexity, we believe these are outweighed by the benefits.

4.5.1 Unbundling Constraints

492 The drivers behind constraint costs have a number of different drivers from those underlying the management of energy, reactive power, transmission losses and black start. The main difference is the seasonal and yearly impact on costs of the planned and unplanned outages. As outlined below, this creates a different risk profile for constraints when compared with the other BSIS components.

493 Below is a table showing the range of forecast costs for constraints and the remaining balancing services components. Also shown are the boundaries of the range of costs that would be expected in 80% of cases (P10 & P90 values). These P10 and P90 points are also shown expressed as a percentage change from the mean value.

	P10	Mean	P90
Constraints Range	£387.6m *20%*	£485.5m	£594.2m *22%*
Remaining Cost Components Range	£454.6m *8%*	£492.6m	£531.5m *8%*

Table 2: Forecast range of costs for constraints and the remaining balancing cost components

494 As can be seen in the table, the range of costs for constraints is considerably wider than that for the remaining cost components.

495 Bundling these two components into a single scheme and determining suitable incentive parameters will ultimately lead to a scheme that does not accurately reflect the relative risk profiles of the set of costs but rather a compromise between them.

496 Combining these different risk profiles and forecast cost ranges for constraints and the remaining balancing cost components in to a single scheme would see the costs of constraints being likely to lead to higher windfall gains and losses than the other areas as a result of changes in constraint cost drivers that are outside the control of National Grid which create the wide range of outcomes for constraints.

497 For example, with a fully bundled scheme with a cap of £15m and 25% sharing factors (using the 2009/10 scheme for this example), a reduction in constraint costs of 10% (or £49m), all other elements being equal, would result in a BSIS profit in excess of £12m. A reduction in 10% may be the result of good National Grid performance. However, due to the uncertainty of constraint costs, a reduction in power price, a change in generator availability behind a constraint boundary or a lower than anticipated connection of new generation would provide a similar result. Therefore, National Grid may receive a windfall gain of £12m.

498 Such windfalls could be reduced with the development and implementation of improved adjustments. However, with the major driver being generation volumes and outage location and length, such adjustments would be difficult to develop and may lead to perverse incentives.

499 With an appropriately designed unbundled constraint incentive, this windfall gain would be reduced as the cap and sharing factors would be lower than the remaining bundled scheme due to the risk profile shown above and the lower level of controllability by National Grid.

500 In addition to the potential for windfall gains and losses, there are a number of market developments that will drive constraints costs, the result of which are currently unknown. These are:

- CAP170[55] - Category 5 System to Generator Operational Intertripping Scheme
- Locational BSUoS[56]
- P229[57] – Introduction of a Seasonal Zonal Transmission Losses Scheme

  P229 seeks to allocate transmission loss costs more appropriately across generators and demand customers. An assessment of the impact of P229 indicates a change in generation patterns. This change in generation pattern may be beneficial to constraints.

501 The impact of these modifications would significantly impact constraint costs post implementation. Due to the uncertain outcome of the implementation these proposals, the potential impact has not been included in this forecast.

502 Therefore, these uncertainties in constraint cost outturns lend support to the unbundling of constraints into a separate incentive scheme with suitable risk and reward profile.

503 Unbundling of constraints will require a methodology to provide some certainty on how balancing actions are allocated to constraint costs.

504 The development of this methodology could be based on existing (or soon to be existing processes) such as the P217[58] constraint flagging or the existing National Grid internal methodology known as the BAAR[59] process. It is also important that any methodology is compatible with those under consideration in other areas such as TAR and Locational BSUoS.

505 One potential method of agreeing a methodology is to develop a licence requirement similar to the requirement to prepare and adhere to the Balancing Principles Statement (a requirement in section C16 licence).

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[55] More information on CAP170 can be found at http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/amendments/currentamendmentproposals/

[56] More information on Locational BSUoS can be found at http://www.nationalgrid.com/uk/Electricity/Charges/modifications/uscmc/

[57] Information on the BSC mod P229 can be found at http://www.elexon.co.uk/ChangeImplementation/modificationprocess/modificationdocumentation/modProposalView.aspx?propID=254

[58] http://www.elexon.co.uk/changeimplementation/ModificationProcess/ModificationDocumentation/modProposalView.aspx?propID=23

[59] BAAR is the Balancing Actions Autopsy report, a National Grid process that assigns reasons to actions and so calculates the costs incurred under BSIS.

506 Such a 'Constraint Costing Methodology Statement' will require industry consultation prior to implementation. The timescales in developing and implementing such a statement is dependent on the timing of Ofgem's final proposals. Therefore, it may not be possible to implement such a methodology at the start of the incentive year. However, it will be possible to reconcile any constraint costs incurred prior to the implementation of the methodology resulting in an accurate allocation of costs across the year.

507 To ensure consistency of outturn against target costs, the same methodology needs to be used to determine the forecast constraint costs and the outturn constraint costs.

508 The unbundling of constraints removes one of the potential barriers to the development and implementation of longer-term schemes, as the volatile nature of constraints costs are removed from the overall scheme target.

509 Therefore, we are proposing that the constraint balancing costs are unbundled into a separate incentive scheme.

4.5.2 Internal and external incentive scheme alignment with unbundling

510 As detailed in section 1.3, the agreed sharing factors for the BSIS are also applied to the internal SO incentive scheme for each year. Therefore, the unbundling constraints and the remaining cost components into separate incentives with different sharing factors would raise a potential issue with the alignment of incentive sharing factors with the internal SO incentive scheme. However, this issue exists at present with the interaction of costs with the TO, as any TO costs incurred in managing BSIS costs effectively have 100% sharing factors, i.e. any costs incurred by the TO in reducing operation costs (such as extended working to reduce the exposure to constraint costs) has a 100% impact on the TO costs. We therefore believe unbundling of constraints does not add to any misalignment of internal and external schemes.

511 As detailed in section 1.6, the issue of this SO-TO interaction was discussed as part of the consultation to the industry, entitled The Potential Enhanced Electricity Transmission Owner (TO) Incentives. Respondents were of the view that aligning the incentive structures should promote a more optimal approach to managing constraints across both SO and TO activities. Unbundling of constraints therefore may offer further opportunity to better align constraint cost incentives with TO costs should incentives on TO costs change.

512 Therefore, we are proposing that the SO internal incentive scheme sharing factors are aligned with the sharing factors agreed for the energy and other cost incentive.

4.5.3 Unbundling of the Remaining Cost Components

513 There are a number of benefits in the unbundling of the remaining cost components into separate incentive schemes, such as reflecting the differences in risk ranges across the components.

514 However, further unbundling will increase the complexities of the scheme. Therefore, we are not proposing any additional unbundling at this time.

Question 31: Do you agree with the benefits outlined for the unbundling of constraints costs and the remaining balancing cost components into separate incentive schemes? What additional issues need to be considered?

4.6 Proposal for Implementation of Multi Year Schemes

515 In developing our initial proposals, we have considered the benefits and drawbacks of a multi-year scheme. We believe that the benefits of a multi-year scheme outweigh the drawbacks and so we are proposing a two year deal be implemented in 2010.

516 As detailed in section 1.3, the SO and TO Opex and Capex targets are agreed for a five year period with the BSIS being agreed on a year by year basis. With this arrangement any efficiency improvements of external costs created by any innovation (which may for example increase internal costs) are rolled up in to subsequent years target's and the innovation is only rewarded in a single year.

517 For example, National Grid may increase the focus on the development of additional service providers (such as the demand side participants) by increasing resources to actively seek new providers. Such additional resources may lead to reductions in external costs that would then be rolled up in to subsequent year's target. However, this additional resource would increase the internal incentive costs; to maintain the level of external cost benefits greater than for the one year, resource costs would continue to be incurred within the internal scheme after the benefits have been realised and the incentive target reset in the external scheme.

518 These internal costs could be recovered by requesting an adjustment to the internal scheme cost target or wait for PCR approval for increases in OPEX. Such an adjustment requires considerable justification and there is an unknown risk that the cost increase may not get regulatory approval. Therefore we feel further improvements could be made and it would be more efficient to implement a multi year incentive that would reward National Grid for investment in additional resources and allow National Grid to decide the most efficient placement of this additional resource where it can create most value.

519 Therefore, aligned internal and external incentives arising from the implementation of a multi-year BSIS scheme internalises these costs decisions to National Grid and allows National Grid the freedom to make the trade offs between the internal and external schemes, removing the barriers to implementing such changes.

520 This is one reason why National Grid believes that a multi-year scheme is beneficial in efficiently incentivising the SO on reducing balancing costs over the longer term.

521 In addition, a longer term scheme would provide some certainty to National Grid on the longer term cost targets, enabling decisions to be made for investments with increased certainty, such as the consideration of investments in cost reduction tools or resources with a longer than one year payback

522 Also, the move to a longer term scheme would reduce the administrative burden on National Grid, Ofgem and the industry on developing, reviewing, responding and implementing the incentive scheme. This will allow the resource to be used to consider how best to manage costs of system balancing in light of the forthcoming changes to the energy industry and development of appropriate incentive scheme in this changed environment.

Question 32: Do you agree that there is a misalignment in internal and external SO incentives caused by different scheme durations?

4.6.1 Multi-Year Constraints Scheme

523 The transmission outage plan is built around the submitted generation outage plans, aligning transmission outages that restrict output of generation with periods of generation shutdown or reduced output and placing outages that require generation to run, when the generation is available.

524 Currently, the outage plan is developed at the year ahead stage for outages in the following financial year. This aligns with planning processes of third parties and allows for optimal coordination. It also offers flexibility to new customers seeking connection to the transmission system.

525 To develop the constraint forecast for the year, assumptions on the export / import volumes for each constraint zone are made with the expected boundary capability of each constraint zone.

526 As described in section 3.5 the constraints forecast is largely dependent on the outages required for new connections due to the length of these outages and the relative inflexibility of the work involved.

527 The current constraint forecast process has good visibility of works required for new connections to the transmission system within the following year and there is also a reasonable degree of confidence in these connection dates. Outages for asset replacement and maintenance can be placed against this background of new connection outages, building an outage plan with some certainty at the year ahead stage.

528 At greater than one year ahead, new connection dates are less certain. Therefore the placement of outages for new connections at greater than one year ahead would currently lead to an increase in changes to the outage plan, and thus the longer term constraint forecast, leading to a higher range of costs and the potential for windfall gains and losses. The lower confidence in connection dates of new generation would also increase the range of forecast costs assuming a static outage programme.

529 The implementation of interim connect and manage will change the new connection process, with new generation no longer having to wait until the wider system reinforcements are completed prior to them connecting to the transmission system. This may result in an increase in the number of new generator connections with firm longer term connection dates (i.e. after the local works are complete).

530 The Scottish Transmission Owners[60] currently submit outage information to National Grid in line with their obligations under the System Operator (SO) Transmission Owner (TO) Code (STC).

531 To change the timescales for submission of information i.e. the submission of a two year ahead outage plan would require changes to the STC which must be approved by all parties. Such a change was discussed as part of the recent consultation on Potential Enhanced Electricity Transmission Owner Incentives, with consultation responses being generally supportive.

532 The process to amend the STC would be expected to take a minimum of three months, assuming no objections were raised to the proposal. Such an STC change would mean that the earliest time outage information could be received for 2011/12 would be early 2010. However, it would be anticipated that the process changes necessary for the Scottish TOs to develop a two year plan would lead to a later implementation date, as would also be expected for National Grid as TO in England & Wales due to the changes required in the internal processes in order to produce and develop a longer term plan.

533 In addition, the impact of a planning process change on third parties will need to be assessed e.g. impact on new connections and DNOs and

[60] Scottish Power Transmission Ltd (SPTL) and Scottish Hydro Electricity Transmission Ltd (SHETL) each own high voltage transmission networks in Scotland.

whether a change can be accommodated that provides overall benefits to the industry.

534 The development of a two year constraint forecast from April 2010 clearly has some issues in terms of certainty of outages as described above. Following the responses to the consultation on Potential Enhanced Electricity Transmission Owner Incentives, it is likely that a number of initiatives will be taken forward to extend the TO planning period for the future. However, whilst it may be possible to develop a more certain constraint volume forecast in the future, given the current processes and procedures both internally and externally, it is difficult to see how such a process could be extended much beyond two years without the need for the development of suitable scheme adjustments.

535 The development of a more detailed longer term planning process with the aim of fixing outages further ahead of real time will take some time to change the internal processes and external interfaces. Responses on the Potential Enhanced Electricity Transmission Owner Incentives Consultation indicated that the start of the next price control may be an appropriate time to implement longer term constraint incentives.

536 To develop a longer-term forecast, there are a number of potential options that could be explored. Below we outline some possible options in the development of a two year forecast:

1. Roll over of constraint forecast cost
2. A 6 month scheme followed by an 18 month scheme and thereafter a 2 year scheme.
3. Ex post incentive scheme
4. Development of a methodology to determine the per unit constraint cost where National Grid are incentivised to beat this per unit constraint cost
5. Two year incentive with four seasonal constraint targets

1. Roll over of constraint forecast cost

537 A method that does not require the forecast of constraint volumes would be the roll over of the current constraint cost target for an additional year. This would result in the agreed target for constraint forecast costs for 2010/11 becoming the target for 2011/12 incentive year (alternatively, an average constraint forecast for the 2009/10 and 2010/11 could be used for 2011/12).

538 This roll over forecast would provide a target for National Grid costs and be included in the BSUoS forecast for 2011/12.

539 However, without appropriate adjustments being made to the forecast, the target agreed could lead to the increase for potential windfall gains or losses due to the outturn volumes in 2011/12 having different drivers than in the 2010/11 forecast e.g. different outage pattern due to different

new connections or other essential works and different volumes due to generation outage programme.

2. A 6 month scheme followed by an 18 month scheme

540 This options premise is that by October 2010, the processes and procedures would be in place to produce a robust two year ahead outage plan and therefore develop a volume based forecast that would take the forecast boundary capabilities into account.

541 Therefore, a 6 month constraint forecast would be developed and agreed with suitable targets and sharing factors. During the summer 2010, an outage plan and therefore a forecast of constraint volumes would be produced and prior to October 2010, an 18 month target for constraints would be agreed.

542 This option reduces the risk of the potential for windfall gains and losses. However, it does assume that the processes and procedures are in place with the Scottish TOs and other critical parties prior to the 18 month forecast being agreed. Furthermore, with uncertain generation connection dates, exacerbated by interim connect and manage, it is likely to be necessary to include some adjustments to the scheme for new connections to mitigate windfall losses and gains.

3. Ex-post incentive scheme

543 Due to the volatility of constraints, the development of an ex-post methodology that would reward National Grid for actions taken to reduce constraint costs could be developed. This methodology would not rely on the development of a forecast for volumes or prices and so would not have to be time limited e.g. for 1 or 2 years.

544 This incentive methodology would reward National Grid for actions taken that had reduced constraint costs. Inversely it would penalise National Grid for actions that were considered inefficient. These actions would be assessed post event to determine the impact they had had on constraint costs. The post event analysis would necessitate engineering resource to quantify the impact of actions.

545 This type of incentive would require a methodology to determine how the actual ex-post costs compared to those that would have occurred had no National Grid action been taken. There are also potential administrative burdens in reviewing and assessing these for National Grid, Ofgem and the wider industry.

4. Development of a methodology to determine the per unit constraint cost where National Grid are incentivised to beat this per unit constraint cost

546 In the absence of a constraint volume to determine the constraint cost forecast, the development of a methodology that calculates a per unit cost (e.g. £/MWh of constraint) for a constraint volumes across each critical system boundary could be implemented.

547 National Grid would then be incentivised to beat this per unit constraint cost when constraints were active on that critical boundary. Whilst such an incentive may help to reduce the unit price it may not incentivise a reduction in constraint volumes.

548 Such a scheme could be developed into a scheme of longer duration than 2 years. However, a significant amount of work is required to assess the system boundary capabilities under intact and outage conditions and extreme operating conditions (full exports on IFA, Interconnectors wheeling power through the UK system, type fault on a generator, fuel shortage). Equally the change in capability due to generation connections and completion of reinforcement works must be assessed for the duration of the scheme.

5. Two year incentive with four seasonal constraint targets

549 As the majority of capital plan outages are placed over the summer months resulting in the majority of constraint costs, a scheme that provides separate constraint incentive targets across the outage seasons could be developed.

550 For example, for a two year incentive, four targets could be agreed (Year 1 April to October and November to March and Year 2 April to October and November to March). These four targets would minimise the windfall gains or losses in each incentive season. In addition, the later outage season targets could be adjusted when a more up to date outage plan and resultant constraint volumes are known.

4.6.1.1 Multi-Year Scheme Summary

551 In summary, developing a two year forecast using the current methodology to determine constraint volumes is not possible at this time and will require changes to National Grid and other third party processes.

552 There are a number of alternative forecast methodologies that fundamentally move away from the existing forecast process. A number of these options will require further careful consideration.

553 We have not at this time explicitly developed a constraints forecast for 2011/12. We seek views on what constraint forecast option we could or should progress in developing a 2 year constraint forecast.

554 Considering the options above, we believe that option 1 – roll over of the current forecast, provides the easiest option to implement. However, to

limit the possibility of windfall gains and losses, splitting the scheme into four seasonal incentives with individual caps and collars with the opportunity to amend the targets for year two may improve the methodology.

555 We are considering the development of a more robust two year constraint forecast process and we are looking at what steps are required to:

- Implement constraint incentive scheme from April 2010
- Consider the implications and impact of extending the outage plan to two years in line with responses received from the Potential Enhanced Electricity Transmission Owner Incentives Consultation (i.e. changes to STC, internal processes, etc).

556 How this option is progressed will be based upon feedback to this consultation and further consideration on this matter.

> Question 33: What option could or should National Grid use to develop a 2 year constraint forecast?

4.6.2 Multi Year Scheme for the Remaining Cost Components

557 With the implementation of appropriate adjustment methodologies (as discussed in section 4.7), the development and implementation of a longer term incentive is both possible and appropriate for cost components of BSIS, excluding constraints.

558 The main drivers outside the control of National Grid are power price and market length.

559 With the continued operation of NIA and the implementation of a reactive power adjustment for changes in power price, the majority of uncontrollable drivers are suitably adjusted for. Therefore a move to a longer scheme will allow National Grid to drive cost savings whilst minimising risks associated with changes to uncontrolled drivers.

560 Therefore, we believe that the implementation of a 2 year scheme will help focus resources and investment in improving the management of costs associated with areas other than constraints.

> Question 34: Do you agree with the benefits outlined for the implementation of a two year incentive? What do you believe the additional benefits and / or drawbacks are of a multi-year scheme?

4.7 Scheme Adjustments

561 As outlined in the mini consultations, there are a number of cost drivers that are partly or wholly out of the control of National Grid. For changes in these drivers away from those used in the forecast, there is the possibility that there is a change in costs. We proposed a number of adjustment methodologies that would adjust the incentive target dependent on key drivers such as power price and market length.

562 The development of suitable adjustment methodologies would reduce the likelihood of windfall gains and losses and also reduce the likelihood of income adjusting events (IAE) and therefore would be the preferred method of adjusting the target for external factors that impact on the costs of system operation.

563 The consultation responses generally supported the development of appropriate indexation. Therefore we are proposing the continued use of the current NIA methodology and the development of a reactive power default price adjustment. In addition, we consider the development of NIA to a daily rather than current half hour methodology, with varying coefficients between seasons.

4.7.1 Net Imbalance Adjustment (NIA)

564 As outlined in the mini consultation, two of the main drivers for energy costs are power price and market length. These drivers are determined by the markets and so National Grid does not have control over these key drivers. When forecasting energy costs, an assumption is made on power price and market length. Changes to these assumptions heavily influence energy costs. Therefore, the accuracy of the forecast for energy to some extent relies on the accuracy of the forecast of power price and market length. Due to the uncertainty in accurately forecasting power price and market length, an adjustment methodology was developed that adjusts the incentivised energy costs for outturn changes in power price and market length. In 2009/10 a revised adjustment methodology was implemented that better adjusts the incentivised costs for changes in power price and market length.

565 As part of the aims and objectives for the development of the incentive for implementation in 2010, the development of improved indexation and adjustment methodologies were outlined. National Grid has undertaken an assessment of the current NIA and considered how this may be improved.

566 In the second mini consultation published this summer, National Grid outlined a number of different proposals that tried to improve the current NIA methodology. As outlined in the consultation responses, any improvement in NIA needs to provide a balance between accuracy and complexity.

567 Following consultation with industry[61], at this stage we are not proposing changes to the current NIA methodology. The operation and performance of NIA will be assessed over the coming winter months.

568 However, from the analysis work undertaken in developing a revised NIA methodology, National Grid believe that improvements in NIA can be made with only a small change in complexity.

569 Therefore, we are presenting the option of changing the NIA calculation from the current half hourly calculation to a daily calculation, with different coefficients for summer and winter, in time for Ofgem consulting on their final proposal.

570 To finalise the potential develop of NIA, we will be publishing a 'mini' consultation. Responses to this consultation will feed into the development Ofgem's final proposals.

571 Calculating NIA daily recognises that, although the market operates on a settlement period basis, and market length and power prices change over such periods, balancing the system requires actions over longer time periods. For example, where additional generation is required to meet demand over the peak period when the market is short, the dynamic parameters of such generation results in costs being incurred over a number of settlement periods, where the market length may have gone long (e.g. the minimum non zero time of a synchronising generator is generally longer than one settlement period). As such, actions taken to resolve market imbalance in a given half-hour will affect the operating costs over a number of settlement periods.

572 The implementation of the NIA methodology proposed above would have a minor impact on the incentive outturn costs and whatever formulation is utilised for NIA, there would be no impact on the overall costs to the industry, recovered via BSUoS, apart from a relatively small proportion related to National Grid's profit or loss in the incentive scheme.

4.7.2 Reactive Power Adjustment

573 Payments for default reactive power services are indexed to RPI and wholesale power price as defined in CUSC Schedule 3 Appendix 1[62] and is calculated monthly based on the relevant month's RPI and month ahead wholesale power price. The formula for calculations can be found below:

[61] http://www.nationalgrid.com/NR/rdonlyres/95D86B42-F2A4-4317-83D5-551F9AE27D7E/36514/Energyconsultation_final.pdf
[62] http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/contracts/

Default Power Price = Base# x (0.5xRPI) + (0.5xPower Price^)

^Power price is based on month ahead forward trade prices.

#Base is a figure defined in CUSC from which default price is indexed.

574 The main drivers are outside the control of National Grid – wholesale power price and RPI. Changes from those forecast for power price and RPI impact on default reactive power prices. Default arrangements make up the majority of the reactive power costs historically and all of the costs over the next forecast period.

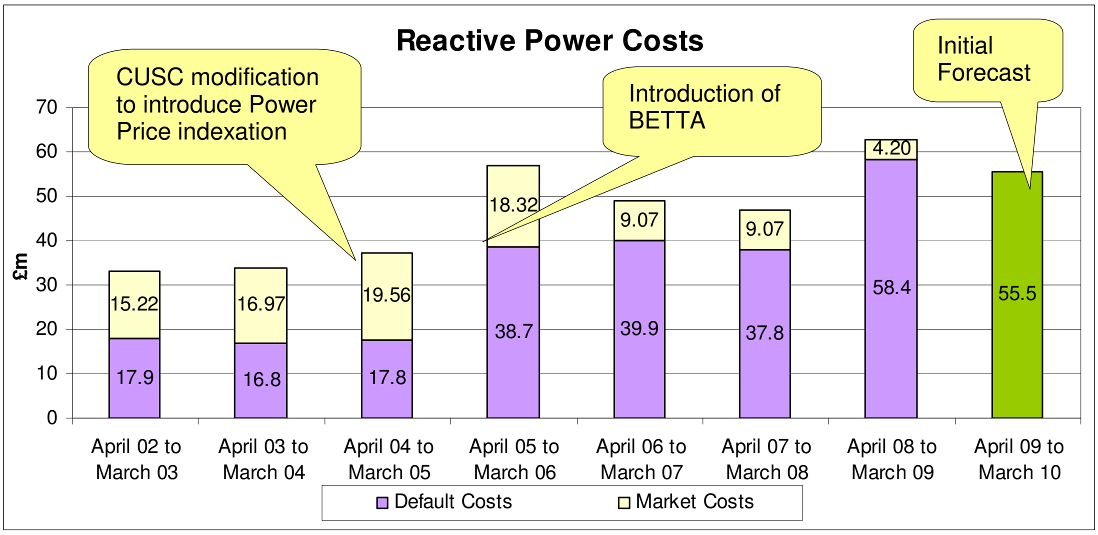

Figure 68: Reactive power costs

575 As can be seen in Figure 68, in 2008/09 over 90% of reactive costs were via the default mechanism. Therefore variations in power price and RPI away from those used in the forecast have a significant impact on the reactive power outturn costs.

576 Therefore the development of indexation that indexes the forecast default price to the actual outturn price would remove the potential windfall gains or losses that can occur for changes in power price and / or RPI away from those used in the agreed forecast.

577 The scheme would work in the following way:

- Forecast volume for each month
- Forecast default reactive price (based on forecast power price and forecast RPI)
- Initial reactive power target set using the forecast volumes and prices

578 Each month the reactive target is revised using the actual default reactive power price and the forecast volumes using a "RIA" term

$$RIA_{monthly} = -1 \times \text{Monthly Forecast Reactive Power Volume} \times \text{Actual Monthly Default Reactive Power Price}$$

Where:

- RIA is the Reactive Incentive Adjustment factor, calculated monthly

- Forecast Reactive Power Volume is the volume assumed in this forecast for each month in 2010/11, in Mvarh

579 This indexation methodology effectively incentivises National Grid on managing and reducing reactive volumes.

580 As an example of how this may work and the potential impact, the method that would have been adopted if reactive power indexation were used in 2009/10 is shown.

- Develop reactive volume forecast
- Forecast default reactive power price (using the power price and RPI assumption and default price formula in the CUSC)
- Provide provisional reactive power cost target
- Revise annual target based on actual default price for each month and the monthly forecast volume
- Outturn costs are based on actual default prices and actual volumes

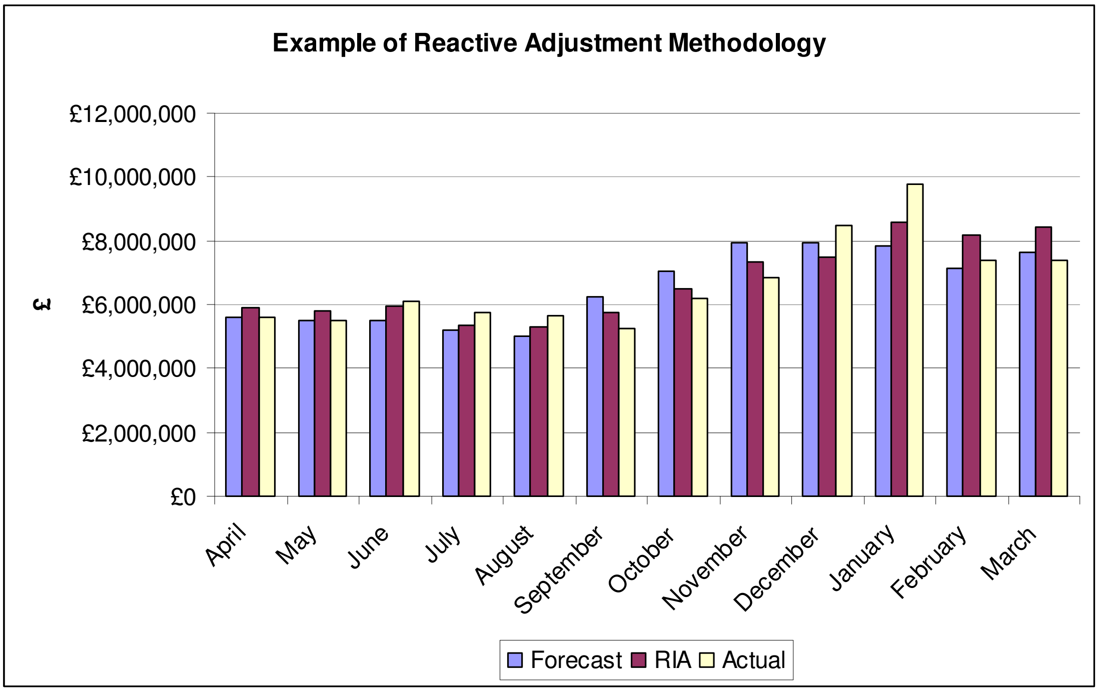

Figure 69: Example of the effect of RIA

581 From the graph above, the impact of changes in default price from that forecast can be seen. The annual target is revised monthly dependant on the outturn default reactive power price. The resultant indexed target

in this example is lower than the initially forecast. This is due to lower power price and RPI outturns than that forecast.

582 Although there are a number of additional drivers that are not fully controllable by National Grid e.g. level of active power flows across the transmission system, we believe that with the within year volatility of power price and RPI removed from the outturn costs via the indexation methodology outlined above, the remaining risks are able to be forecast or are manageable.

> Question 35: Do you agree with the introduction of a Reactive Index Adjustment based on actual default reactive power prices? Do you agree with the form of this adjustment as presented here?

4.7.3 Additional Adjustments

583 National Grid proposed a number of additional adjustments within the mini consultations for constraints and transmission losses.

584 The majority of respondents to these mini consultations stated that they did not support the implementation of these adjustments. The main points raised were:

- Adjustments would reduce or remove the incentive to reduce costs
- Although respondents agreed that the adjustments identified were cost drivers, they believed that National Grid had some control over these drivers
- The requirement to develop appropriate adjustments was reduced or removed if the scheme was limited to one year in duration

585 Considering the complexities of developing a robust adjustment methodology for the main drivers for constraints and transmission losses, and the potential improvement in accuracy of such a change, National Grid do not believe that it is appropriate to develop such adjustments at this time.

> Question 36: Do you feel at this stage that there is a case for any additional adjustment terms to be introduced at this stage?

4.8 Constraints – Treatment of Fault Outages

586 Due to the nature of fault outages, National Grid cannot accurately forecast them for a given year as, by definition, they are unknown at the time the scheme is agreed.

587 Fault outages occur due to:

- weather related incidents, such as lightning

- third party damage, such as the digging up of cables
- equipment failure

588 The potential costs of managing such system events are not currently included within the constraint costs forecast. In addition, although the cost of arming intertrips are included in the constraint forecast, no forecast is included for the costs associated with a system to generation tripping scheme firing.

589 Within the mini consultation on constraints we outlined a number of options for alternative treating of fault outages are:

- Raising Income Adjusting Events where the costs of a fault outage exceed a pre-determined threshold amount
- Pre-Agreed Circuit Compensation
- Average Compensation
- "Insurance Pot"

590 The consultation responses suggested that there was no preferred option and that further consideration of how to treat fault outages was required. However, there was some support for the current methodology i.e. raising an IAE for significant fault outage costs and also for including a 'forecast' of fault outage costs in the overall constraint target

591 National Grid believes that the risks associated with fault outages and intertrip tripping fees needs to be recognised within the BSIS forecast. As outlined in the mini consultation, there are a number of potential options that can be considered.

592 National Grid is proposing that the costs of fault outages are included in the constraints forecast. To develop a cost, we have taken the average costs of fault outages since BETTA go-live. Therefore we are proposing that an additional £12m per annum is included in the constraint forecast.

593 The inclusion of expected fault outage costs will reduce the potential for IAEs as the costs of fault outages will be borne by National Grid (except in extreme events e.g. prolonged double circuit outage causing significant constraint costs).

594 At this time National Grid has not included an allowance for fault outages within the forecasts presented here.

Question 37: Do you believe that National Grid should include an allowance for fault outage costs within the constraint forecast? Do you agree with the level set?

4.9 Transmission Losses – Incentive Development

595 In our first mini consultation, National Grid proposed two alternative incentive options for transmission losses.

596 Zonal Transmission Losses Forecast Incentive: this proposal considered if there was any value to the industry in the publication of zonal transmission losses forecast data.

597 The general response to the consultation was that such an incentive was not appropriate and would not add value at this time. A number of respondents suggested that, dependent on the outcome of the decision to implement P229 (implementation of zonal transmission losses), consideration should be given if such a modification was implemented.

598 Transmission Losses Procurement Incentive: this proposal outlined the development of an incentive where National Grid procured all transmission losses volumes (approximately 6TWh per year) on behalf of the industry. The incentive would be to decrease costs below an agreed target.

599 This proposal did not get much support from consultation responses, although one respondent suggested that this option should be further investigated.

600 As outlined in the consultation responses, additional analysis is required to assess the validity of alternative transmission losses incentives.

601 Therefore, National Grid is not proposing to progress an alternative transmission losses incentive at this time.

4.10 Transmission Losses – Reference Price

602 The transmission losses reference price is based on the forward wholesale power price plus an adjustment to replicate the then shadow price of carbon[63] (as implemented in 2008/09). The forward price used was £47.09/MWh (the average forward price for 2009/10). The adjustment made for the shadow price of carbon was calculated using the differential between the market price of carbon and the then shadow price of carbon taking into account the relative generation types and efficiencies. An indicative adjustment for the differential in the shadow price of carbon and the market price of carbon of £7.92/MWh was calculated for 2009/10 resulting in a transmission losses reference price of £55.00/MWh. This transmission losses reference price is utilised for the entire year.

603 To more accurately reflect the cost of losses, it may be beneficial to improve the granularity of the calculation of the reference price.

[63] http://www.defra.gov.uk/environment/climatechange/research/carboncost/pdf/HowtouseSPC.pdf

604 However, there is little or no benefit in developing a more complex methodology that will have implications for the IS systems. Therefore, at this time, National Grid is not proposing any changes to the granularity of the Transmission Losses Reference Price.

Question 38: Do you agree that Transmission Losses should remain bundled with the other components of BSIS, excluding constraints?

Question 39: Do you agree that the Transmission Losses Reference Price should remain a fixed value for the duration of the scheme?

4.11 Scheme design

605 When developing each of the incentive scheme designs, the following was considered:

- range of costs over which the incentive is effective
- central forecast
- mean forecast derived from forecast models
- level of control of costs by National Grid
- accuracy of a two year forecast
- risk ranges of each cost component

606 When considering the development and implementation of a two year scheme, the relative risk ranges and the accuracy of the forecast needs to be taken into account. When comparing constraint forecast risk ranges and the accuracy of the second year constraints forecast to the other cost components, we believe that the unbundling of constraints from the remaining costs components leads to a more targeted incentive. This is covered in more detail in section 4.5.

Question 40: Do you agree with the criteria used to develop the incentive scheme design? If not, what additional points should be considered?

607 Therefore, as outlined above, National Grid's preferred scheme for implementation on 1st April 2010 is a:

- single year unbundled constraints incentive scheme
- two year scheme for the remaining bundled cost components with current NIA methodology and reactive power default price adjustment

608 Alternative scheme options proposed are:

- single year incentive scheme

- two year fully bundled scheme with the constraint cost forecast being included at a later date for year two

609 The incentive ranges developed represents the forecast uncertainties as well as an assumption of potential cost reductions. These uncertainties influence our thoughts when developing a scheme. The greater the uncertainties, the higher the risk that external factors outside of the control of the system operator will influence costs.

610 In addition, we believe that any scheme should incentivise National Grid over the widest possible range of costs and provide us with a balanced risk / reward profile.

4.11.1 Scheme design for Single Year Constraint Incentive Scheme

611 Using the criteria above we have developed the following risk / reward incentive profile for the constraints incentive for 2010/11:

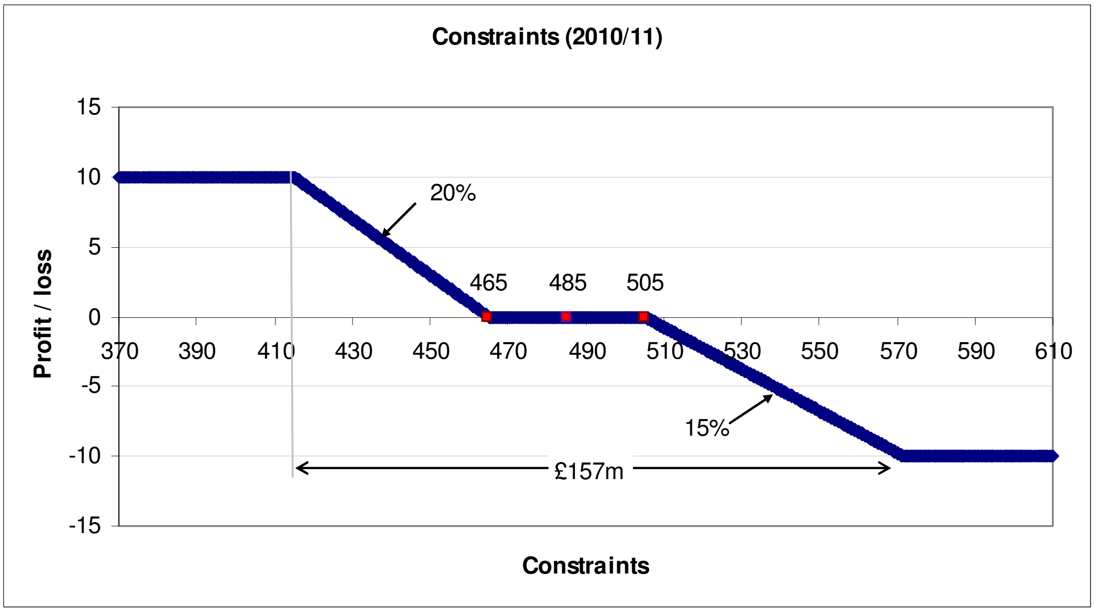

Figure 70: Single year constraints incentive scheme for 2010/11

612 The deadband and sharing factors, have been proposed to provide a wide range of costs in which National Grid are incentivised over whilst providing a suitably targeted incentive.

Scheme	Target	Upside sharing factor	Cap & Collar	Downside Sharing factor	Deadband
Constraint incentive for 2010/11	£485m	20%	£10m	15%	£40m

613 It can be seen that the sharing factors and the cap and collar are lower than this years scheme with the deadband being wider. This reflects the

forecast range of costs being greater than this year's fully bundled scheme and the greater uncertainty over the forecast costs.

614 Further, given the central forecast presented in section 3, National Grid would expect to make zero profit or loss from this scheme.

Question 41: For the unbundled constraints scheme, do you agree with the parameters used? If not, what parameters should be implemented? Please explain your rationale for any changes.

4.11.2 Scheme design for Multi Year Incentive for Remaining Balancing Cost Components

615 Using the criteria above we have developed a multi year incentive scheme for the remaining balancing services excluding constraints. The scheme has two single year incentive targets, with the individual yearly targets agreed for each incentive year with the incentive reward / penalty being realised each year.

616 The development of two single year incentives use the relative forecasts in each year to derive the incentive targets and deadbands.

617 The graph and table below show the incentive for the first year i.e. 2010/11:

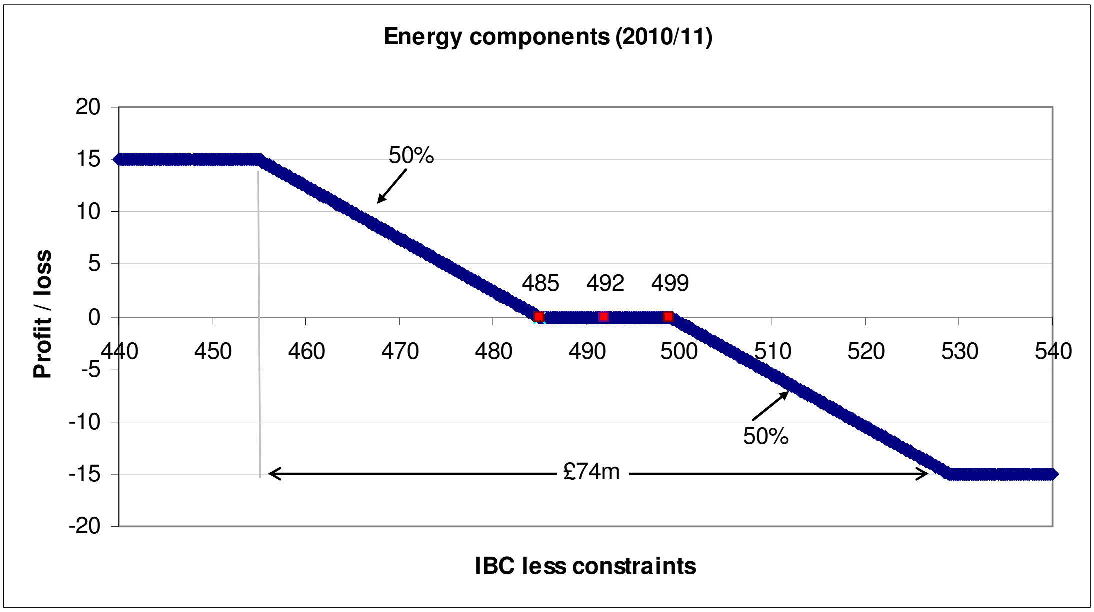

Figure 71: Balancing services excluding constraints incentive scheme for 2010/11

Scheme	Target	Upside sharing factor	Cap & Collar	Downside Sharing factor	Deadband

Year 1 incentive parameters for balancing services excluding constraints	£492m	50%	£15m	50%	£14m

618 The graph and table below show the incentive for the second year i.e. 2011/12:

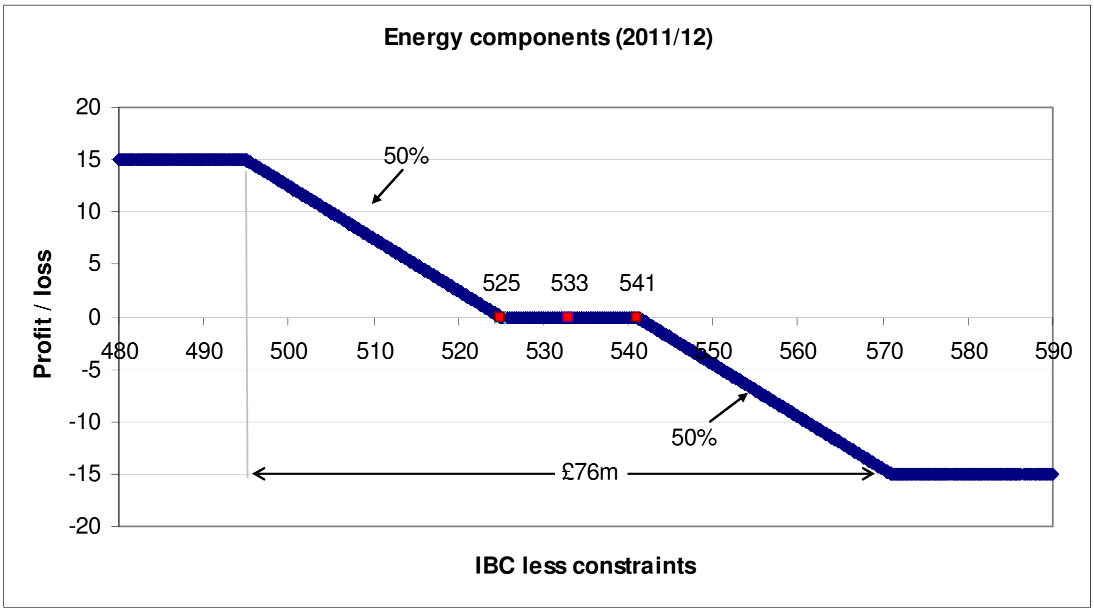

Figure 72: Balancing services excluding constraints incentive scheme for 2011/12

Scheme	Target	Upside sharing factor	Cap & Collar	Downside Sharing factor	Deadband
Year 2 incentive parameters for balancing services excluding constraints	£533m	50%	£15m	50%	£16m

619 The incentive sharing factors and caps and collars are the same for both years. The target and deadband differences reflect the difference in the relative annual forecasts and the ranges.

620 The sharing factors are higher than those for the 2009/10 incentive scheme. This reflects our increased confidence in the our forecasting

methodology, [the removal of the risks presented from constraints into a separate scheme], the ability of NIA to adjust the incentive for changes in power price and market length and the current forecast for 2009/10 being in line with our forecast expectations.

621 An increase in the sharing factors (when compared to the incentive for 2009/10) provides a sharper more focused incentive on driving costs down with the corresponding increase in focus on ensuring costs do not increase above the deadband.

Question 42: Do you agree with the implementation of two single year incentive schemes for all balancing costs except constraints? Do you agree with the parameters used? If not, what parameters should be implemented? Please explain your rationale for any changes.

4.11.3 Scheme design for Fully Bundled Single Year Incentive

622 The scheme below is a fully bundled scheme with all balancing cost components included. This scheme provides a comparison with our favoured schemes above and previous years incentive options.

623 To develop the scheme we used the overall central forecast cost, the mean forecast cost derived from the models and the risk range.

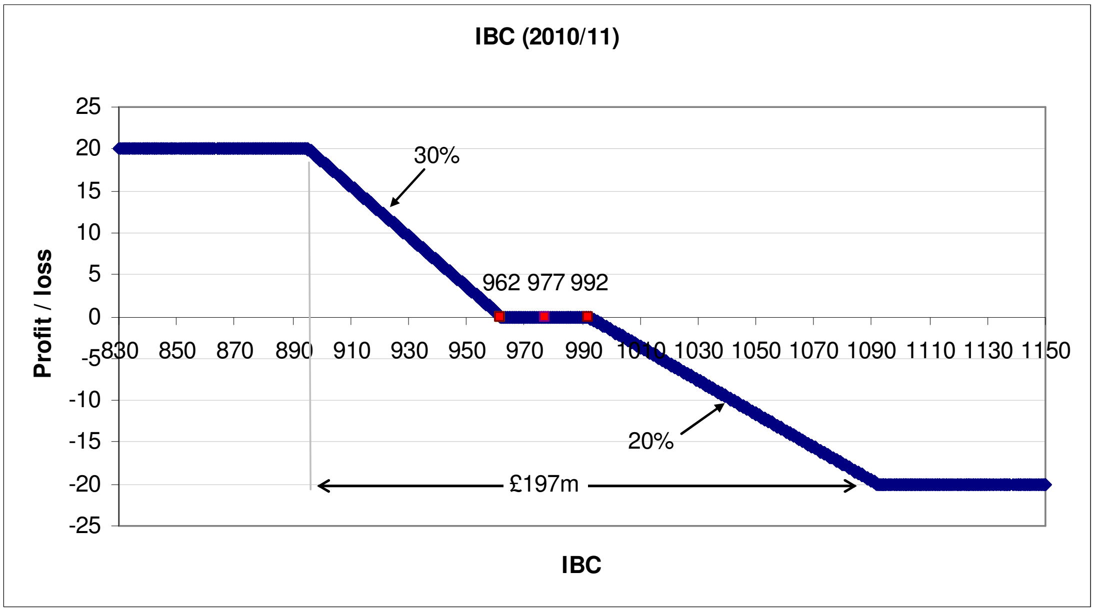

Figure 73: Fully bundled one year incentive

Scheme	Target	Upside sharing factor	Cap & Collar	Downside Sharing factor	Deadband
Fully bundled for	£977m	30%	£20m	20%	£30m

2010/11					

624 As can be seen in the graph and the table above, the sharing factors and caps and collars are higher than those for the 2009/10 incentive scheme. This reflects our increased confidence in our forecast, the ability of NIA to adjust the incentive for changes in power price and market length and the current forecast for 2009/10 being in line with our forecast expectations.

625 The increase in the sharing factors (when compared to the incentive for 2009/10) provides a sharper more focused incentive on driving costs down with the corresponding increased focus in ensuring costs do not increase above the deadband.

626 The sharing factors are lower than for the ‘remaining cost components’ unbundled incentive and the deadband is higher due to the inclusion of constraint costs into the scheme which increase the overall risk range and uncertainty with the forecast.

Question 43: Do you agree with the parameters used for the one year fully bundled scheme? If not, what parameters should be implemented? Please explain your rationale for any changes.

4.11.4 Scheme design for Fully Bundled Two Year Incentive

627 In addition to the fully bundled scheme above, the implementation of a fully bundled two year incentive may be preferred. The two year forecast for the ‘remaining cost components would be used to determine the majority of the bundled costs with the 2010/11 constraints forecast being used for the first year target and a yet to be developed constraints forecast for 2011/12 used to develop the target for the second year incentive.

628 Year 1 of the scheme would look the same as the scheme above with year 2 of the scheme having lower sharing factors due to the risk of constraint costs increasing.

Question 44: Do you agree with the development of a two year fully bundled incentive? How should the constraint cost forecast for year two be included in the incentive target e.g. agreed post scheme or some form of constraint forecast developed pre-implementation?

4.12 Summary of options

629 As outlined above, we believe there are a number of benefits of the implementation of a multi-year scheme. Therefore, we are proposing a

two year incentive scheme is implemented from April 2010. This two year incentive will include all balancing cost components except constraints.

630 Due to the complexities of developing a two year forecast for constraints, our preferred option we are proposing that constraint costs are unbundled from the rest of the incentive scheme into a separate one year incentive.

631 As shown above, the range of possible incentive costs for all components excluding constraints is narrower than for the current fully bundled scheme. Therefore, we have designed the incentive excluding constraints to have higher sharing factors than the scheme in place in 2009/10.

632 We are proposing to have lower sharing factors and smaller caps and collars to reflect the range of costs risks for the constraints incentive scheme in 2010/11.

Question 45: Do you agree with the scheme options presented here for implementation from April 2010 and what is your preferred option? If not, please provide an explanation as to why and any alternatives that you would like to see developed.

Section 5
Information Systems Impacts

This section discusses the potential impact of scheme design changes on the current settlements and payment systems.

5.1 Summary

633 As outlined previously, the BSIS costs are captured in the BSUoS charges paid by CUSC participants. BSIS costs can be categorised into two main groups; external costs and internal costs.

634 In the transmission licence the external BSIS costs are referred to as the Incentivised Balancing Costs (IBC) and can be defined as follows;

IBC = [CSOBM+NIA+BSCC+TLIC] + [minor terms]

Where;

Acronym	Full Description
IBC	Incentivised Balancing Costs
CSOBM	Cost to System Operating for the BM
NIA	Net Imbalance Adjustment
BSCC	Balancing Services Contract Costs
TLIC	Net Cost of Transmission Losses
Minor Terms	The minor terms are other costs associated with the balancing services, which are relatively small in comparison to the other terms.

635 With the scheme that we are proposing, the following impact on BSUoS can be shown:

$BSUoS_{(ext)}$ = CSOBM +BSCC + (External incentive payment)

Where:

External incentive payment includes the incentive payment for the unbundled constraints scheme and the profit or loss for the remainder of the scheme

636 Therefore, with respect to BSUoS, the impact of the proposed changes is on the profit or loss element of the scheme that can increase or decrease the overall BSUoS costs.

637 When determining the BSUoS charges, the current system provides an estimate of the profit or loss dependent on the relative targets and outturns for the scheme.

638 As there is currently one incentive payment element, changes will be needed to incorporate the calculation of the incentive payment associated with the unbundled constraints incentive and the remaining component incentive.

639 Therefore it is anticipated that a change to the current systems will be required to facilitate this change e.g. data sent to Logica to will require the splitting of the three incentive costs.

5.2 Way forward

640 To ensure these changes are in place for 1st April 2010, work will need to be started in January 2010. However, in January, the final scheme design will be unknown. Therefore, any preliminary works that are required to ensure an April 2010 implementation may not be required if the final scheme design changes from that proposed.

641 Design of the systems could be undertaken when the scheme design is known in March 2010. At least three months is required to develop and implement the revised systems. However, this will result in a potential delay to the implementation of the systems beyond 1st April 2010 (possibly until July 2010). This will result in some form of reconciliation of the costs incurred prior to the new systems being implemented.

642 In addition, the introduction of a multi-year scheme and / or schemes with components of varied durations will have an impact on the invoicing and reconciliation’s of BSUoS charges. Possible changes include revisions to the invoicing timetables currently in place to suit the scheme duration(s) and changes to the Settlement Calendar, as required.

5.3 Impact on Industry

643 We believe that a change in the incentive scheme structure will have an impact on industry systems. The amount of change will depend on the degree of change in the new BSIS scheme from that currently in place. This will result in format changes to files sent to and used by participants with consequential impacts on Users’ receiving systems. Allowing at least three months from a decision to the implementation should allow Users time to make the appropriate modifications to IS systems.

Question 46: What impacts will a change in incentive scheme structure and consequential changes to the BSUoS data have on your IS systems?

Question 47: If your systems will be impacted by a change to scheme structure what information will you require and in what timescales in order to accommodate the change?

Section 6 Summary

6.1 Summary

644 National Grid is obligated under the terms of the Transmission Licence to balance the system in a safe, efficient, economic and co-ordinated manner. The application of financial incentives encourages National Grid to invest in systems and resources to ensure BSA costs and risks are economically and efficiently managed and that innovative ideas and procedures are developed to reduce costs in return for a share of any savings delivered.

645 The Balancing Services Incentive Scheme (BSIS) is designed to deliver financial benefits to the industry and consumers from reductions in the costs associated with operating the national electricity transmission network.

646 The incentive scheme provides a focus on key areas where National Grid is able to create value for the industry and consumers, allowing National Grid to retain a share of any value created or to bear a share of the costs should targets not be met.

647 This consultation presents our initial proposals for the BSIS starting in April/2010. It describes the incentive scheme, provides an overview of its performance so far, explains the incentivised cost components of the scheme and their drivers and finally present our current forecast, along with a set of options for the incentive scheme starting in April 2010.

648 Section 1 introduces National Grid and the principles behind the Balancing Services Incentive Scheme (BSIS). An overview about 2009/10 BSIS progress is detailed along with information about the consultation process that has been recently carried out in preparation for the 2010/11 initial proposals.

649 Section 2 sets out the components from which Balancing Services costs are incurred. It also describes the relationship and drivers of these various areas thus providing an overview of BSIS costs.

650 Section 3 looks at the method by which our forecast is constructed and the assumptions made therein. The outcome from this is presented along with the ranges of costs anticipated for the various components for the costs of Balancing Services from April 2010.

651 In section 4 we set out a high level overview of the current SO incentive scheme, the aims of incentive development for implementation in April 2010, feedback from the Mini consultations and an overview of the incentive options being proposed.

652 Section 5 outlines the potential changes required to Information Systems depending on the agreed shape and duration of the incentive scheme.

653 Input from the industry is of paramount importance in the development of incentive proposals. Therefore, we would welcome any feedback from the industry on the content of this consultation.

Question 48: Do you have any comments regarding the information provided within this consultation?

Question 49: Do you have any comments regarding this consultation process? What improvements would you like to see in future years?

Section 7
Consultation Questions

This section lists the consultation questions from the document.

7.1 Consultation Questions

654 The questions below have been constructed to help us determine the industries view on the potential for the development and implementation of an adjustment methodology.

655 Answering the questions will allow us to focus our attention on developing a methodology for inclusion in our initial proposals for the introduction of a scheme for April 2010.

656 The questions are not an exhaustive; if you have any further points you would like to raise please do so.

7.2 List of Consultation Questions

1	Have all cost drivers for Energy, Reactive Power, Black Start and Transmission Losses been captured and correctly identified as being within or outside National Grid control
2	Have all the cost drivers for Constraints been captured and correctly identified as being within or outside National Grid control
3	Is historic market length a suitable proxy for future market length?
4	Do you agree with the conclusions we have reached with respect to the observed changes in NIV since BETTA go-live? If not, why not?
5	What do you believe is the impact of wind on market length at this time; how do you see this varying as wind penetration increases and what do you believe are the key drivers? What additional analysis could be carried out to determine the current and / or future impacts?
6	Do you agree with our base case scenario for NIV? If not, which scenario should be used and why?
7	Are there any other factors or scenarios that you believe should be considered in deriving a NIV forecast?
8	Do you believe that installed wind capacity will increase as indicated? If not, please indicate how you believe the rate will change and why.
9	Do you believe that nuclear generation will maintain its current level of availability
10	Do you agree with the assumptions made in producing a frequency response volume forecast? If not, please indicate why not.
11	Do you agree with the assumptions made in producing a fast reserve volume forecast? If not, please indicate why not.
12	Do you agree with the assumptions made in producing a reactive volume forecast? If not, please indicate why
13	Do you agree with the assumptions made in producing a demand forecast? If not, please indicate why not.
14	Do you agree that the relationship between the volume of margin actions and market length is an appropriate input to the
15	Do you believe that wind generation will displace conventional generation behind key boundaries? Do you believe that conventional generation behind constraint boundaries will stop running?
16	Do you have any comments on the assumptions made in producing a margin volume forecast? Are there any other considerations that should be included in the margin volume assumption?
17	Do you agree that the Argus forward price values are an appropriate measure of wholesale prices over the forecast period? If not, please indicate why not.
18	Do you agree that Bloomberg is a suitable source for Carbon prices and the Euro to Sterling conversion rates used within the forecast? If not please indicate why not.
19	Do you agree with the assumptions made in producing a BM energy price forecast? If not, please indicate why not.
20	Do you agree with the assumptions made in producing a BM Response price forecast? If not, please indicate why not
21	Do you agree that a 12 month average of the prices for Footroom is a reasonable assumption? If not, please indicate why not.
22	Do you agree with the assumptions made in producing a Fast Reserve price forecast? If not, please indicate why not.
23	Do you agree with the assumptions made in producing a Margin price forecast? If not, please indicate why not.

24	Do you agree with the assumptions made in producing a Balancing Services price forecast? If not, please indicate why not.
25	Do you have a view on the future trend of STOR contract prices?
26	Do you have any further comments regarding this forecast or the assumptions made in its development?
27	Do you have any comments on the background and assumptions made in constructing the constraints volume forecast?
28	Do you have any comments to make regarding the assumptions made in constructing the constraints price forecast?
29	Do you agree with the methodology used to forecast the second year of a two year scheme for all components except constraints?
30	Do you have any suggestions for other factors that should be taken in to consideration for the second year?
31	Do you agree with the benefits outlined for the unbundling of constraints costs and the remaining balancing cost components into separate incentive schemes? What additional issues need to be considered?
32	Do you agree that there is a misalignment in internal and external SO incentives caused by different scheme durations?
33	What option could or should National Grid use to develop a 2 year constraint forecast?
34	Do you agree with the benefits outlined for the implementation of a two year incentive? What do you believe the additional benefits and / or drawbacks are of a multi-year scheme?
35	Do you agree with the introduction of a Reactive Index Adjustment based on actual default reactive power prices? Do you agree with the form of this adjustment as presented here?
36	Do you feel at this stage that there is a case for any additional adjustment terms to be introduced at this stage?
37	Do you believe that National Grid should include an allowance for fault outage costs within the constraint forecast? Do you agree with the level set?
38	Do you agree that Transmission Losses should remain bundled with the other components of BSIS, excluding constraints?
39	Do you agree that the Transmission Losses Reference Price should remain a fixed value for the duration of the scheme?
40	Do you agree with the criteria used to develop the incentive scheme design? If not, what additional points should be considered?
41	For the unbundled constraints scheme, do you agree with the parameters used? If not, what parameters should be implemented? Please explain your rationale for any changes.
42	Do you agree with the implementation of two single year incentive schemes for all balancing costs except constraints? Do you agree with the parameters used? If not, what parameters should be implemented? Please explain your rationale for any changes.
43	Do you agree with the parameters used for the one year fully bundled scheme? If not, what parameters should be implemented? Please explain your rationale for any changes.
44	Do you agree with the development of a two year fully bundled incentive? How should the constraint cost forecast for year two be included in the incentive target e.g. agreed post scheme or some form of constraint forecast developed pre-implementation?
45	Do you agree with the scheme options presented here for implementation from April 2010 and what is your preferred option? If not, please provide an explanation as to why and any alternatives that you would like to see developed.

46	What impacts will a change in incentive scheme structure and consequential changes to the BSUoS data have on your IS systems?
47	Question 47: If your systems will be impacted by a change to scheme structure what information will you require and in what timescales in order to accommodate the change?
48	Do you have any comments regarding the information provided within this consultation?
49	Do you have any comments regarding this consultation process? What improvements would you like to see in future years?

Section 8
Further Information

8.1 Further Information

657 Further information on the drivers of the costs of system operation can be found in the mini-consultations published during the summer of 2009. These can be found at the web address below:

http://www.nationalgrid.com/uk/Electricity/soincentives/docs/

658 National Grid also make information available regarding individual balancing services available from a dedicated area of our website, sub-divided by the service in question. This can be found here:

http://www.nationalgrid.com/uk/Electricity/Balancing/services/

659 National Grid also makes regular presentations to Operational Forums on aspects of system operation. These presentations can be found on the National Grid website at the following address, via the menu on the left.

http://www.nationalgrid.com/uk/Electricity/Balancing/operationalforum/

Section 8
Contact details

If you would like to discuss any issue on SO Incentives, please contact us via the contact details below.

To register your interest in receiving future communications on this consultation process please email: SOIncentives@uk.ngrid.com

On the web:
New dedicated web pages for this process are available at the following addresses:

Electricity SO Incentives: http://www.nationalgrid.com/uk/Electricity/
Gas SO Incentives: http://www.nationalgrid.com/uk/gas/

Talk to us:

Gas
John Perkins Tel: 01926 656337 john.perkins@uk.ngrid.com

Electricity
Malcolm Arthur Tel: 01926 654909 malcolm.arthur@uk.ngrid.com

General enquiries: SOincentives@uk.ngrid.com