Mini-Consultation
Document 3/09

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

Consultation on the Development of SO Incentives for Constraints

Version 1.0

Issued 9 September 2009

Responses requested by 7 October 2009

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Section 1

Executive Summary

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 the on the engagement with industry and development of Initial Proposals for SO Incentives to be implemented 1st April 2010.

To enable the development of robust proposals, NGET will publish 'mini' consultations to address specific key issues surrounding the development of multi-year schemes, and the potential for bundled / unbundled schemes.

This consultation addresses constraint cost component which accounts for approximately 25% of the Balancing Service Use of System (BSUoS) total costs. The aim of the document is to present and seek views from the industry on how the current incentive for constraints could be further developed.

Responses to this consultation will be used to inform the development of our Initial Proposals for SO incentives for implementation in April 2010. We aim to consult on our Initial Proposals in October 2009.

The key themes in this consultation are summarised below:

Bundled Vs Unbundled

- We seek views on the separation of constraint costs from other costs of system operation.

Development of Adjustment terms

- We seek views on the development of adjustment terms to update the constraint cost incentive dependant on key drivers.

Treatment of Fault Outages

- We seek views on the treatment of the costs incurred as a result of unplanned outages of transmission system equipment

Scheme Duration

- We seek views on the potential benefits of changes to the scheme duration

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

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Section 1 Introduction

This section provides an overview of the SO incentives development process being followed for 2010/11 and places this document in the context of the overall incentive development process.

1.1 Introduction

2 National Grid Electricity Transmission (NGET) is the National Electricity Transmission System Operator (NETSO), defined hereon in as National Grid for simplicity. In our role as NETSO, we are subject to a number of financial incentive arrangements which encourage us to minimise the overall costs to consumers and to support the efficient operation of the wholesale electricity markets.

3 National Grid is incentivised to balance the system in an efficient, economic and co-ordinated manner. The application of financial incentives enables NGET to invest in systems and resources to ensure balancing costs and risks are efficiently minimised.

4 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 be penalised should targets not be met).

5 These incentives are designed to deliver financial benefits to the industry and consumers from reductions in the costs associated with operating the electricity transmission network.

6 Via an open letter, published on 28 May 2009[1], Ofgem 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 process and topics for this year's consultation. NGET's response to this letter can be found on the NGET Website[2].

[1] http://www.ofgem.gov.uk/Markets/WhlMkts/EffSystemOps/SystOpIncent/Documents1/Open%20Letter%20final.pdf
[2] http://www.nationalgrid.com/NR/rdonlyres/D68DE8C6-DB21-4513-B60E-98B3AE709305/35809/SOInitialProposalsTimetableNGOpenLetter.pdf

7 In their letter, Ofgem recognise 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 customers and smaller suppliers in this year's process. In response to this NGET 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 our website.[3]

8 If you would like NGET 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 in Section 9 of this document.

9 As outlined in Ofgem's open letter, there are a number of key issues that need to be addressed to develop robust Initial Proposals. We intend to break down these issues by publishing a number of mini consultations. NGET will be issuing three independent mini consultation documents this summer, the focus of each document is summarised below. Each document will have a four week consultation period.

Document	Topics
1	Reactive power, transmission losses and black start
2	Energy (e.g. Reserve and Response)
3	Constraints

10 The consultations have been split in this way as we believe these topics are to a significant extent standalone and they will benefit from separate consideration. Within each of the mini consultations, we will focus on the reasons for whether it would be appropriate to unbundle the specific components, if there are appropriate external measures to use for adjustment and the suitability for multi year schemes. The mini consultation documents will not contain detailed proposals for SO Incentives schemes to apply from 1 April 2010. They are intended to invite industry views on a range of issues that might drive the form and structure of incentive schemes.

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

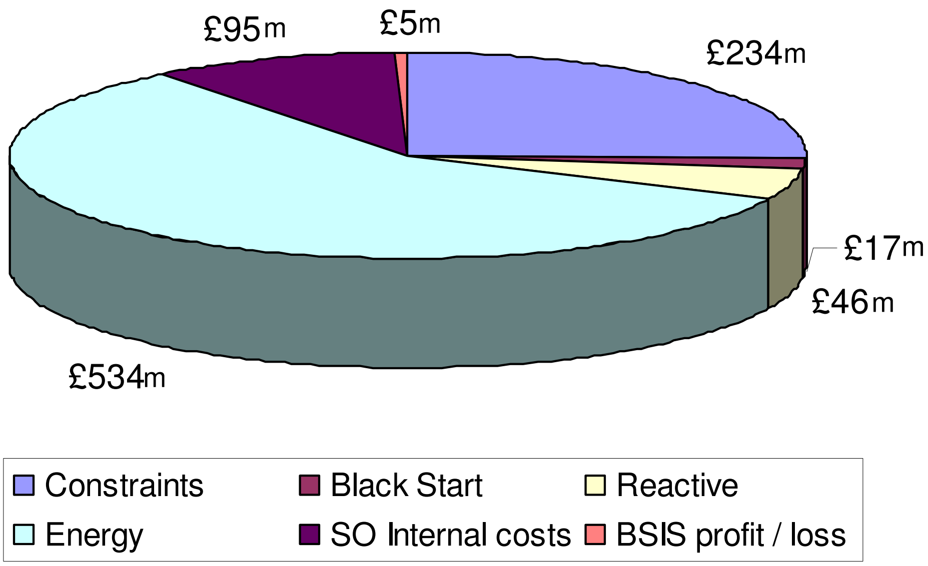

Figure 1: 2009/10 BSUoS cost forecast

11 Figure 1 shows the relative costs of each of the components that make up the Balancing Service Use of System (BSUoS) cost forecast for 2009/10 (approximately £931m).

12 This consultation document is the third of our proposed ‘mini’ consultations and sets out our thoughts on the development and implementation of incentives for the costs of managing transmission system constraints

1.2 Interaction with other reviews

13 There are currently three licensed electricity transmission companies in Great Britain. National Grid Electricity Transmission plc owns the high voltage transmission network in England and Wales. Scottish Power Transmission Ltd (SPTL) and Scottish Hydro Electricity Transmission Ltd (SHETL) each own high voltage transmission networks in Scotland.

14 Ofgem has asked National Grid, supported by SPTL and SHETL to explore whether there are benefits of introducing new or revised transmission incentive arrangements for Transmission Owners and also to explore the options for designing incentives to deliver benefits to consumers. A consultation document is presently being developed based upon this work and will be published around mid September.

15 This consultation will explore potential improvements to the management of System Capacity which is a key driver of constraints, as further described in section 2.5.1.3, and therefore has an interaction with this consultation.

1.3 Document Structure and consultation process

16 The document is structured as follows:

- Section 2 focuses on the background to constraint costs
- Section 3 discusses the benefits of unbundling the constraint component of the scheme
- Section 4 provides some options for potential adjustment terms
- Section 5 discusses treatment of fault outages
- Section 6 considers options for scheme duration
- Section 7 provides a summary
- Section 8 lists the consultation questions
- Section 9 has the contact information
- Appendix A – Current Methodology by which constraint costs are captured

17 The outputs from this consultation, along with feedback received through discussions with industry and Ofgem, will be used to develop our Initial Proposals for incentives to apply from 1 April 2010. Our aim is to issue an SO Incentives Initial Proposals consultation in October.

18 On conclusion of the Initial Proposals consultation, NGET will issue a consultation report incorporating the responses received from interested parties which will be published on our website. The report and all responses will be sent in full to Ofgem. In early 2010, Ofgem will then develop and consult on its Final Proposals for SO Incentive schemes, prior to implementation.

19 Below is a high level outline of the proposed timetable.

Process Milestone	Proposed Date
Publication of mini consultation documents	July/August 2009
Publication of Initial Proposals	October 2009
Industry event / workshop	November 2009
Ofgem to provide initial comments	November 2009
Initial Proposals consultation period closes	December 2009
Ofgem consultation on Final Proposals	Early 2010
Scheme go live	April 2010

20 Responses to this consultation 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. Responses to this consultation are requested by 7th October 2009.

Responses to this consultation should be sent to
soincentives@uk.ngrid.com
by 5pm on 7 October 2009

Section 2 Background

This section sets out the background to constraint costs and discusses the main drivers for volumes and costs.

2.1 Current Incentive Arrangements

21 National Grid is incentivised to balance the system in a safe, efficient, economic and co-ordinated manner. The application of financial incentives enables National Grid to invest in systems and resources to ensure balancing costs and risks are economically and efficiently managed.

22 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 BSIS incentive format has been in place since NETA implementation in 2001

23 The scheme has been designed to allow National Grid to retain a share of any value created or to bear a share of the costs should targets not be met.

24 The current balancing incentive 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.

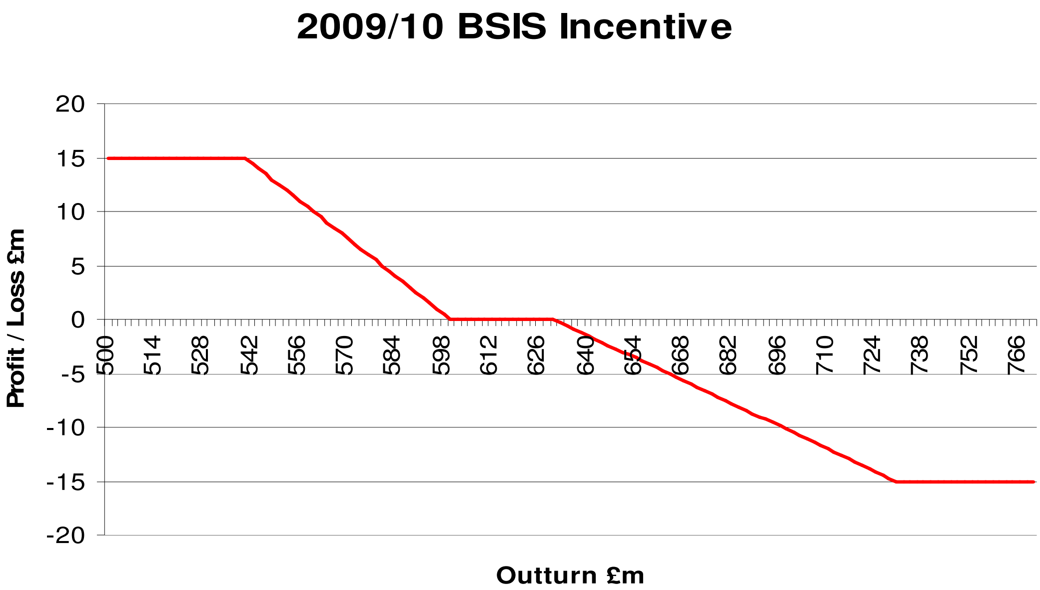

Figure 2: BSIS Profit / Loss Profile

25 Figure 2 shows the current incentive arrangements. For changes in BSIS costs away from the target, the industry and National Grid share in the benefits or disbenefits.

26 Balancing services procured by National Grid are split into the following categories:

- Constraints
  Balancing services used to manage system flows

- Energy related services
  Services used balancing generation and demand. This includes frequency response and reserve as well as final balancing of generation and demand

- Reactive Power
  Services used to manage system voltages

- Black Start
  Services used to re-energise the system in the event of a total or partial system shutdown

- Transmission losses
  The energy lost in the transmission of power across the system

27 Changes in each cost component feeds into the overall BSIS incentive cost pot. To achieve an overall incentive profit, the overall summated costs across all areas must be below the incentive target.

28 Figure 3 shows the relative cost of each of the incentivised balancing components for BSIS year 2009/10 as at July 2009.

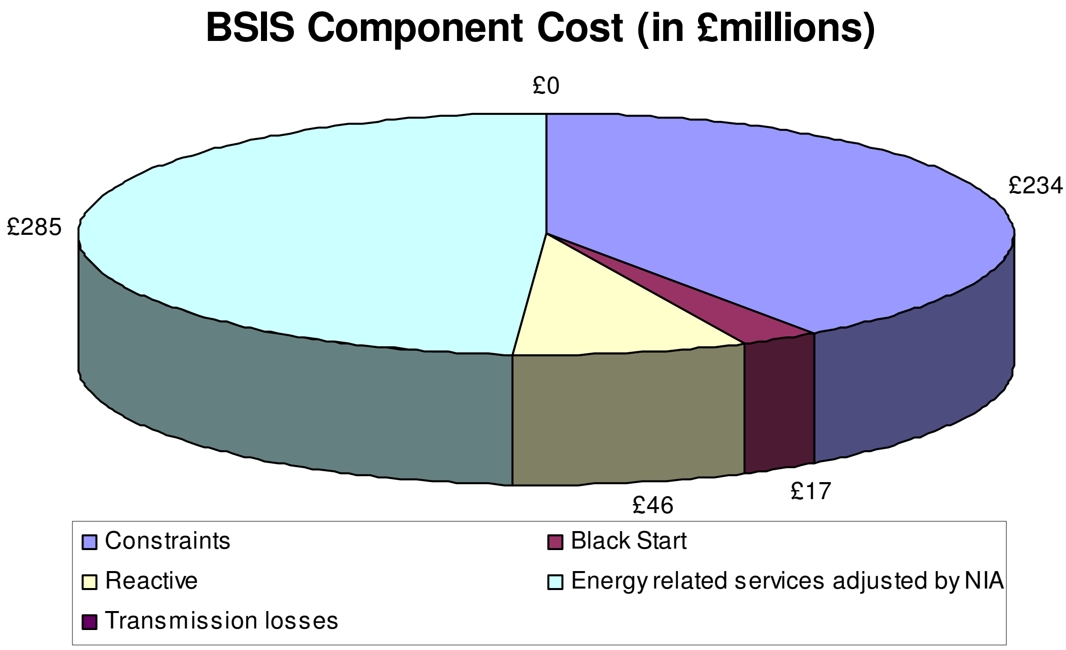

Figure 3: 2009/10 BSIS cost forecast (as at July 2009)

29 BSIS, which is presently forecast at £582m and BSUoS, as would be expected, share a number of components. To move from BSIS to BSUoS (as shown in Figure 1) the following elements need to be added:

- The Net Imbalance Adjustment (NIA) is an adjustment used in BSIS with respect to the energy 'component' for changes to market length and wholesale power prices. This is presently forecast at £249m

- SO internal costs relates to National Grid's costs associated with its SO activities, such as building, staff and IT costs. These costs are also incentivised with the scheme comprising of an 'incentivised' element and a 'non-incentivised' element, which passes through certain of National Grid's costs. The latter consist of costs that National Grid cannot control for example business rates. The overall internal forecast is presently at £108m

- Transmission losses adjustment, as further described in the first mini consultation[4]. This is presently forecast at £0m

- Profit or loss from BSIS. This is presently forecast to be £4.5m profit for 2009/10. This is National Grid's share of the reduction in incentivised costs; currently forecast to be £33m below the BSIS target Figure 2 provides further detail on how this share is calculated.

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

30 Currently constraint costs are fully bundled within the overall Balancing Services Incentive Scheme (BSIS) and constitute part of the annually agreed target. For constraints there is no specific adjustment mechanism in BSIS for drivers that are outside of National Grid's control.

31 Section 3 of this consultation considers the merits of unbundling constraints from other incentivised costs. Sections 4 and 5 consider the development of an adjustment term or terms that would update the constraint cost incentive dependant on key drivers. Section 6 considers the duration of the current incentive scheme and considers the rationale for remaining with a yearly incentive or moving to a scheme of a different duration.

2.2 Constraint cost history

32 The costs incurred for the management of transmission system constraints within England and Wales were a significant element of the costs of system operation at the introduction of incentive schemes in 1996 and before. However successive transmission system reinforcements, new working methods and improved transmission outage planning arrangements, ensured these costs for England and Wales were significantly reduced to an outturn of £13.5m for 2005/06 out of a total of £84m for GB as a whole.

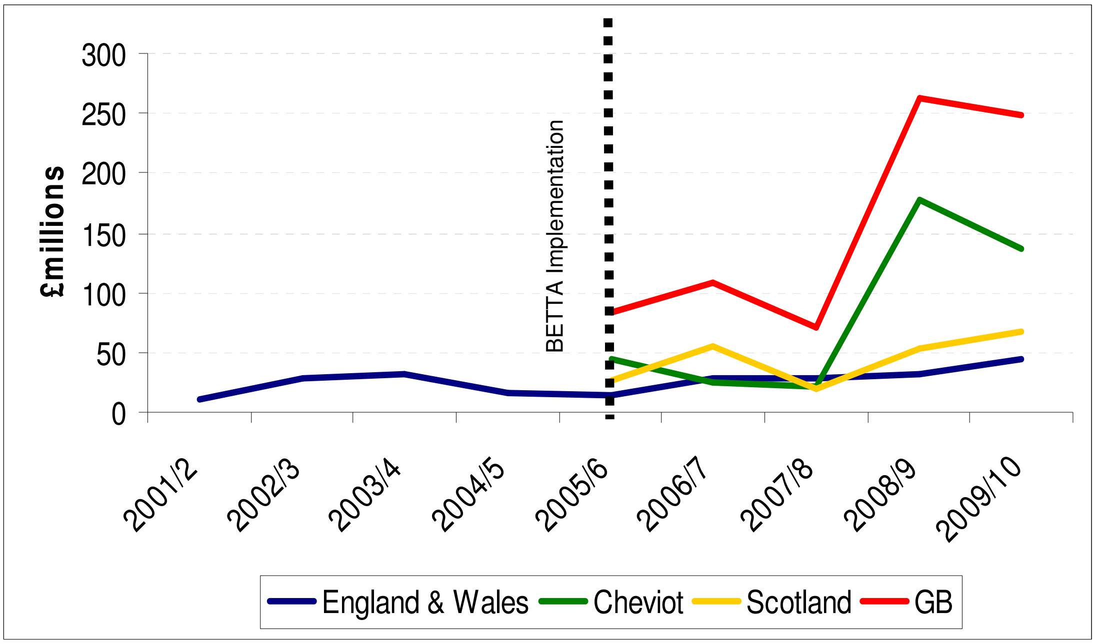

Figure 4: Constraint Costs

33 As shown in Figure 4, the introduction of BETTA in 2005 resulted in an increase in constraint costs as all market participants were exposed to National Grid resolving system limitations that occur within the Scottish transmission system and across the circuits that connect Scotland to England and Wales (E&W) (known as the Cheviot or B6 boundary).

34 Constraint costs have remained high since BETTA go-live due to the limitations inherent within the Scottish network and at the Cheviot boundary. Prior to the introduction of BETTA, the commercial availability of the Cheviot boundary was limited to the physical transmission capability. The introduction of BETTA removed this limit and parties who had acquired internal Scottish access rights for existing, or soon to be commissioned, generation had these rights transferred into GB access rights under the CUSC. However, the physical capability of the interconnection between the E&W and Scottish systems could not accommodate this new commercial requirement. As a result, the Cheviot boundary, did not (and does not) meet the requirements of the National Electricity System Security and Quality of Supply Standards (NETSSQSS)[5]. As such, derogation was sought by, and was granted to, the respective Transmission Owners for non-compliance with NETSSQSS for this boundary.

35 As the Cheviot boundary is non-compliant (i.e. has a lower capability then is required to transport the available Scottish generation), this leads to an increase in constraint costs due to the increase in constraint volumes. In response to both this, and the desire to connect significant amounts of renewable generation in Scotland, the relevant transmission companies have embarked on a programme of reinforcement and expansion (known as the Transmission Investment for Renewable Generation (TIRG) works) that goes some way to alleviate this transmission capacity shortfall.

36 Constraint costs in recent years have been exacerbated by outages required to complete the Transmission Investment for Renewable Generation (TIRG) works and general reinforcement works necessary to connect new generation. The introduction of Interim Connect and Manage will allow increased levels of generation to connect before wider reinforcement works are completed. It is anticipated that this will result in increased constraint volumes and therefore constraint costs.

37 Constraint costs have also increased in recent years within the England & Wales networks. This has largely been driven by a combination of fault outages, unusual weather (flooding in Yorkshire and the South-West), and limitations in plant running with LCPD[6]. With the equipment that makes up the transmission network reaching the end of its operational life there has also been an increase in the number of outages required to perform maintenance or replacement.

38 With the costs of managing constraints having shown significant increases since BETTA, and again in recent years, this document

[5] The NETSSQS is National Electricity Transmission System Security and Quality of Supply Standard. The NETSSQSS officially replaced the GBSQSS on 24th June 2009 upon ‘ GO-ACTIVE’ of the Offshore regime. http://www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode/DocLibrary/

[6] LCPD is the “Large Combustion Plant Directive”

explores some options for the development of System Operator incentives to manage constraint costs.

2.2.1 Historic Constraint Volumes and Costs

39 Figure 5 shows constraints costs since BETTA Go-Live, broken down by category and by location.

40 Constraints can be viewed in three categories, Intact, Planned and Faults:

- Intact

  Where all transmission equipment is available for use (in service) and limitations of transmission capacity exist, the resultant constraint is referred to as 'Intact'. Reinforcement works to the transmission system or permanent changes to the generation and demand portfolio within the group are required to provide a lasting solution to such constraints.

- Planned

  Removing equipment from service for construction work or maintenance increases the power flowing on other system routes. This can exacerbate existing system issues and can result in additional constraints or create wholly new ones. Mitigation of constraint volumes and costs from planned outages are discussed further in this section when considering drivers.

- Faults

  Equipment failure or damage requires an outage to repair or replace the equipment. In the same manner as a planned outage, this limits the transfer permissible. Fault outages, by their nature, cannot be forecast and can not be subject to normal planning practices and so can lead to high constraint costs. Treatment of fault outages and their impact on constraint costs are discussed further in Section 5.

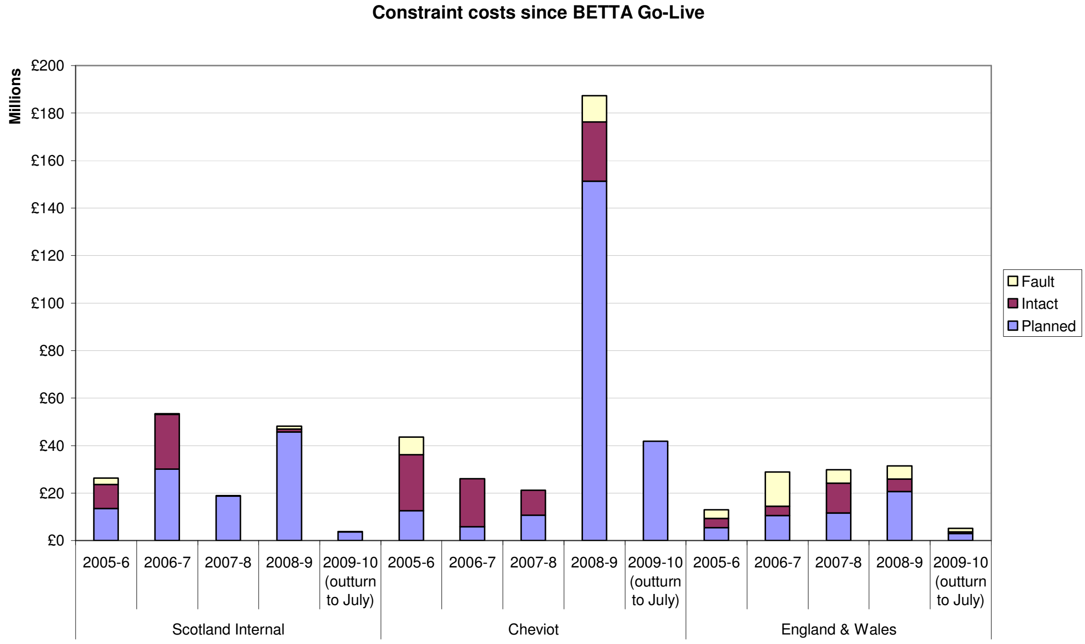

Figure 5: Constraint Costs by type and location

41 As can be seen, the majority of costs are associated with planned outage work on the system. However, intact system conditions and fault outages can impact on the overall constraint costs. Also it can be seen that constraint costs in 2008/09 were considerably higher than in previous years driven by high volumes of constraints across the Cheviot boundary as a result of extended outages and high generation output.

2.3 What Causes a Constraint?

42 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 were 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.

43 As shown in Figure 6 below, the volume of constraint is dependant on the generation in excess of demand 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.

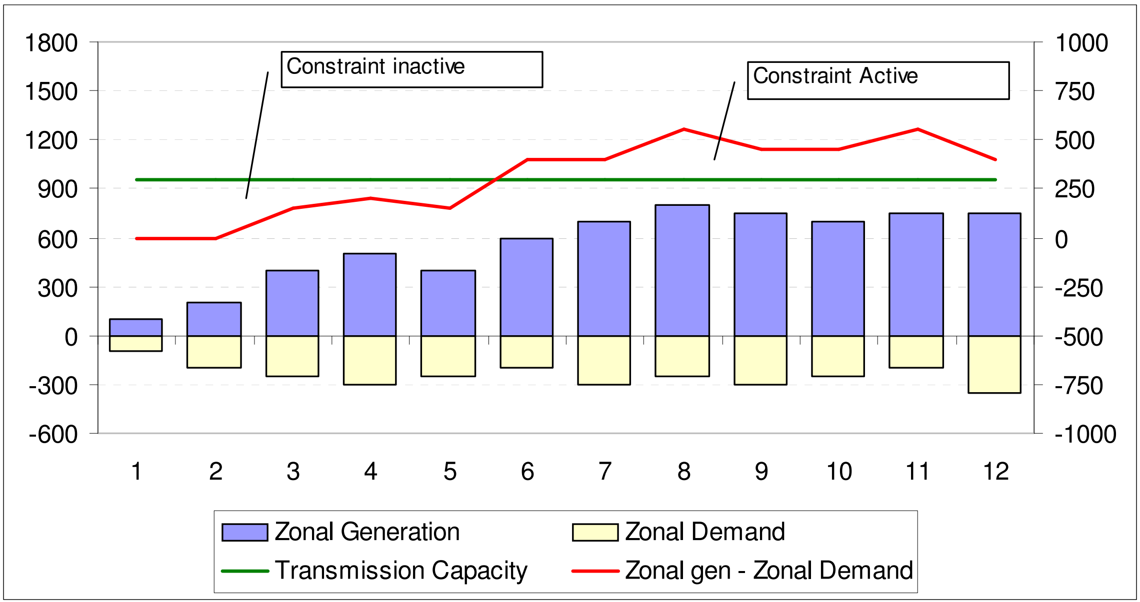

Figure 6: Volume of Constraints

44 The green line indicates the system boundary capability. 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.

45 A finite capability exists to transfer power in either direction across a boundary. Where constraints require that the transfer out of an area is reduced, by reducing generation or increasing local demand, these are termed "Export" constraints. Circumstances where generation within the local group needs to be increased, or demand reduced, are termed "Import" constraints. The example shown in Figure 6 is an export constraint.

46 The limits of transfer capability occur for the following reasons:

- Thermal limitations of the transmission equipment

Power transmission leads to heating of equipment. The thermal capability of the equipment is based on the ability of an asset to dissipate heat. If the temperature is allowed to reach certain levels, this will lead to failure of the asset. This can lead to cascade tripping and widespread system disturbance. The heating effect is managed through control of power flows.

- Voltage excursions outside of limits set in NETSSQSS[5]

The NETSSQSS defines planning and operational limits for voltage at customer interfaces for both sustained periods of operation (steady state system conditions) and post system disturbance. These limits are set to ensure power quality is maintained for customers and that there is sufficient voltage margins for secure system operation.

- Generator stability issues

System stability describes the ability of the transmission system to remain in synchronism before, during and after system disturbances. Were the system be allowed to become unstable, generators may lose synchronism with system speed or pole slip. This results in damage to the generation units and other equipment.

- Thermal limitations of third party assets – such as those belonging to DNOs

47 Failure to manage these issues may result in equipment damage, with the resultant long term outage to fix or replace either transmission or user equipment. In other circumstances a constraint may result in unacceptable voltages leading to the potential wide spread issues. By way of an example, the failure to successfully manage thermal and voltage limitations led to the blackout in the North East of the USA in 2003.

48 The limitations of system transfer capability can be inherent to the system design, as in the case of the Cheviot boundary or are caused by outages, planned or due to system faults, of other system equipment.

49 Management of these conditions requires the System Operator to take actions to resolve or prevent the constraint occurring by the most economic method available. Actions that may be taken by National Grid in its role as SO in resolving constraints include:

- Reconfiguring the transmission system
- Requesting the Transmission Owner[7] (TO) to reschedule the outage, for example to align a Transmission System outage with a generator outage or 'nest' with another outage
- System Operator led Transmission investment, e.g. installation of new intertrips or Reactive power compensation equipment by the TO at the request of the SO
- Accepting bids and offers in the balancing mechanism
- Undertaking locational energy trades
- Agreeing Pre-Gate Balancing Transactions
- Implementing bilateral contracts that change or limit generation output
- Selection of generation intertrips
- Requesting the TO provide enhanced short term increases in capacity

[7] National Grid in England & Wales, Scottish Power Transmission Ltd and Scottish Hydro-Electric Transmission Ltd in Scotland

50 In more extreme circumstances, particularly where a severe fault outage has occurred or other options are unavailable, the following may also be necessary:

- Issue of Emergency Instructions
- Requesting voltage reduction on the low voltage network
- Requesting demand control within the affected group

51 The assessment of which actions are taken to manage constraints, as well as other activities that the System Operator undertakes, are set out in the Balancing Principles Statement and regularly audited[8].

2.4 How are constraint costs incurred?

52 Alternative actions taken to manage constraints incur different costs. As shown in Figure 1, constraints make up approximately 25% of BSUoS costs.

53 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 reschedule outage(s) to align them with a generator outage. However, further action is often required to manage a constraint.

54 Reconfiguring the transmission system can be carried out at no cost, however some areas of the network are more amenable to this kind of engineering solutions than others and this is not always an option.

55 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 arrangement, can be utilised assuming the necessary generator and transmission infrastructure is in place and appropriate agreements in place. Use of a generation intertrips scheme will involve an arming fee and also a tripping fee to be paid if the scheme operates both of which will increase the overall cost of constraints.

56 As discussed earlier, management of transmission system constraints is achieved by the most economic method available as set out in the Balancing Principles Statement[8]. This includes changing the output of generation using the Balancing Mechanism, forward trading or bi-lateral contracts that change or limit generation output.

57 Figure 7 shows the breakdown of constraint costs between actions taken in the Balancing Mechanism and trades, intertrips and contracts.

[8] http://www.nationalgrid.com/uk/Electricity/Balancing/transmissionlicensestatements/BPS/

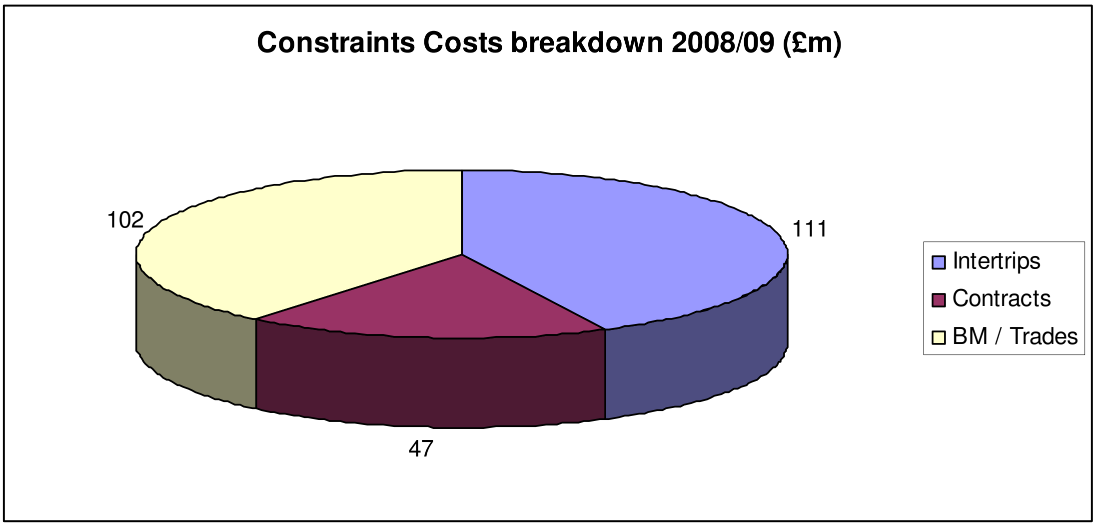

Figure 7: Constraint Costs by resolving action 2008/9

58 There are three stages to managing a constraint in the Balancing Mechanism or via locational trades. These are:

- Resolve the local constraint
- Ensure that sufficient system margin is maintained
- Rebalance the energy position of the overall system

59 The overall cost of the constraint is then the sum of the costs involved in each area:

$$\text{Cost} = (Vc \times Pc) + (Vm \times Pm) + ([Vc\text{-}Vm] \times Pe)$$

Where:

- Vc is the Volume of Constraint at price Pc
- Vm is the Volume of Margin at price Pm
- And Pe is the price of energy

2.4.1 Costs to alleviate the Constraint

60 The first stage to alleviating a constraint in system operation timescales is to identify the most economic method available to alter the generation output or local demand level such that the transfer between the local area and the wider network is reduced to a level that the transmission system can sustain.

61 In the event that an Export constraint exists this will mean locating the unit(s) with the most economic bid prices[9] and accepting these bids.

[9] The Bid price in the Balancing Mechanism is payable to National Grid (unless of course the bid price is negative). The generator's energy imbalance position remains unchanged as a result of a bid and the generator benefits from any fuel savings as a result of reducing their output following the acceptance of a Bid. Thus the highest positive Bid price is normally the most economic.

62 Two situations can arise in this case, dependant on the overall market length. In a balanced market, these Bids will reduce the level of generation relative to demand and so create an energy imbalance that will need to be resolved in order to maintain system frequency.

63 Where the overall market is Long (excess generation) Bids taken for a constraint will also resolve some of this imbalance. However, due to the need to take the Bids from a limited number of parties they may not represent the best prices that could have been achieved without the constraint being present and so represent an increase in costs compared to an unconstrained system.

2.4.2 Cost to preserve system margin in the Balancing Mechanism

64 System Margin is the total generation that can be achieved by units that are currently connected to the transmission system or can be achieved in short timescales. Energy balancing components of the BSIS scheme are discussed in detail in the mini consultation published August 20th[10]

65 With an Export constraint limiting the amount of generation that can be accessed this will reduce the maximum level of generation available to National Grid. As such, additional units may need to be synchronised to provide this additional generation capacity outside of the constraint group.

66 In order to do this National Grid will look at the combination of Offers, minimum run-times and notice periods on units that are not despatched by the market and determine the lowest cost method to create the additional margin. In the absence of the constraint, those actions could not have been necessary, thus in our costing methodology we assume the most expensive margin units are for headroom replacement on active export constraints.

2.4.3 Cost to rebalance energy in the Balancing Mechanism

67 Replacing system margin will typically involve taking Offers on units that were not previously running. These Offers will offset (replace) some of the bids that were taken to resolve the initial constraint and so help to keep overall generation and demand in line.

68 However, in most cases the volume of Bids and Offers will not be equal and opposite and so additional Bids or Offers will be required elsewhere to balance the generation and demand position. For example, if 100MW of bids were taken to resolve a constraint but replacing the energy and margin lost behind the constraint requires the synchronisation of a unit that has a SEL of 250MW. This leaves a net position of +100MW. To ensure that the overall generation and demand at that time is balanced an additional 150MW of bids are required.

[10] Previous Mini-consultations can be found here: http://www.nationalgrid.com/uk/Electricity/soincentives/docs/

69 These additional Bids or Offers will create additional costs that have come about as a result of the initial constraint.

2.4.4 Costs of other actions to manage constraints

70 As stated earlier, National Grid will also assess the use of bi-lateral agreements and/or other methods to alter the output of generation at lower cost than could be achieved in the Balancing Mechanism. Examples of these methods include forward trades and Pre-Gate Balancing Transactions. Committing the generator ahead of real time introduces a risk that the constraint limit may not be breached by the flows from self dispatched generation and thus the action, and cost, is not required. Therefore, although there are price benefits of resolving constraints via pre-gate trades, there are risks that the actions taken would not have been required for actions in the BM

71 In addition, System to Generator tripping services may be utilised to reduce the volume of generation that has to be constrained prior to a fault occurring[11]. 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.

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

2.5 Constraint Cost Drivers

73 Constraint costs are driven by

- The volume of actions required
- Availability of system to generation tripping schemes
- The price of those actions
- The price of replacement actions
- Replacement margin costs

[11] 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.

2.5.1 Volume of Actions

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

- How much generation is self-despatched in the zone. This itself is a function of how much and what of type generation is connected in that region and the relative economic conditions in which they operate
- How much demand is being consumed in the zone
- What the capacity of the circuits connecting that zone to the rest of the system are
- How long the constraint exists on the system

2.5.1.1 Generation pattern

75 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 balancing mechanism.

76 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

77 Generators supply National Grid with information on their intended outage plans (an obligation under the Grid Code – section OC2) and therefore provide an indication of times when there will be a restriction on their operation.

78 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 method 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.

79 The placement of outages can greatly reduce the likelihood of constraint costs occurring. However, where a transmission circuit outage is placed to coincide with a generation outage (as per the OC2 data), there is a risk that the generation outage may move, resulting in the potential for constraint costs to be realised. National Grid has presently no influence over the placement of generation outages and changes to the original plans. Therefore, this is a risk presently outside of the control of National Grid.

80 The implementation of Locational BSUoS[12] 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.

Question 1 - Do you believe that the drivers for the volume of generation have been identified? How much control do you believe National Grid has on volumes?

2.5.1.2 Demand levels

81 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.

82 The volume of constraints is influence by the level of demand as shown in Figure 6. However, there is presently limited scope to use demand as a method to manage constraints at present although efforts have been made in recent years to encourage demand side participation in the Balancing Mechanism and other services.

83 For export constraints, demand would need to be increased to alleviate the constraint. This would require users to increase their energy usage. This may not be in line with their requirements at the time required. Therefore, this is generally not an option currently used.

84 For import constraints, demand would need to be reduced to manage the constraint. This would require consumers to reduce their energy output. This may be possible from demand centres with a large enough capacity such as large energy users like cement works or large industrial sites.

85 National Grid has some control over the level of demand via contracts with demand side providers to supply constraint services, although there have historically been a limited number of such contracts. National Grid can forecast demand to a reasonable accuracy, an important factor in determining the necessary action required to manage a constraint.

2.5.1.3 System Capacity

86 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.

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

87 However, there are a number of intact system restrictions e.g. 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.

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

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

89 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 costs 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.

90 Within Scotland National Grid 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)[13] for STOs and in the Grid Code[14] 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.

91 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.

[13] Procedure STCP11
[14] Operating Code no. 2

92 Any changes to the final outage plan requested by National Grid[15] allow the STOs to recover reasonably incurred costs from National Grid. A nominal allowance of £1m[16] 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.

93 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.

94 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 England and Wales (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.

95 As discussed in the introduction to this consultation, National Grid is preparing a consultation for publication around mid September on a range of proposals that explore potential improvements to the management of System Capacity.

2.5.1.4 Transmission System Faults

96 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.

97 The impact of fault outages on system balancing costs is not currently recognised within the present BSIS incentive. For example, no provision is included for the costs associated with a system to generation tripping scheme firing. As such, though National Grid manages the impact of fault outage by all means possible, the costs incurred ultimately lead to windfall losses.

[15] The definition of an 'outage change' is given in NGET's Transmission Licence, Special Condition AA5A, Part 2(ii), paragraph 21A.
[16] 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.

98 Fault outages and alternative treatment of the risk is discussed in detail in Section 5.

2.5.2 Price

99 As discussed in 2.4 above, the cost of resolving a constraint within the Balancing Mechanism is made up of price of actions to alleviate the constraint, plus the action required to preserve system margin and the action required to rebalance energy.

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

101 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 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.

102 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[17] 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.

103 The use of intertrips can significantly influence constraint costs. For operational intertrips, the costs are set out in the CUSC and are generally set to reflect the costs of providing the service. For commercial intertrips, providers can submit prices at market levels. Therefore, there is a risk that commercial intertrip prices that are in place at the year ahead stage could increase prior to utilisation. To help manage this risk, National Grid on the 27 February 2009 raised a CUSC amendment proposal (CAP170) seeking to reduce potential constraint costs by limiting the costs associated with certain commercial intertripping schemes.

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

2.5.2.1 Alleviation and Energy Rebalance

104 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 Balancing Mechanism. 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.

105 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 8. This factor contributed to increased costs relative to those forecast. 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.

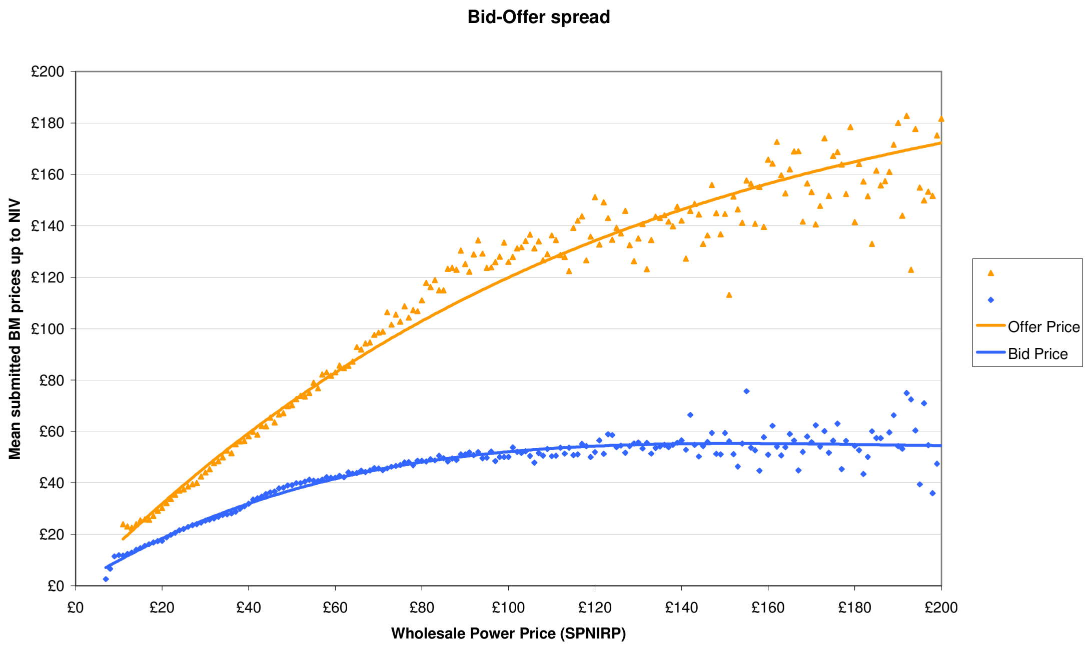

Figure 8: Bid – Offer spread

2.5.2.2 Replacement margin costs

106 The costs of replacement margin actions are a function of prevailing system conditions and the level of generation self-despatched by the market and the disposition of such generation. 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.

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

Questions 3 - Do you consider that there are elements within these cost drivers that are within National Grid control? What are these and how do you believe these should be considered going forward?

2.5.3 Future Drivers

2.5.3.1 Transmission Access and Interim Connect and Manage

107 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[18].

108 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[19].

109 In May Ofgem issued a press release announcing a temporary relaxation of industry rules to reduce connection lead time for generation. This relaxation, Interim Connect and Manage (ICM), allows generation seeking an earlier connection date to do so by approaching National Grid. While the focus has been on connection of renewable generation, ICM is designed to accommodate the advancement of all generation.

110 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 SQSS by Ofgem. Once the customer signs their offer, National Grid submits this request for derogation.

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[18] 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

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

111 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 B6 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.

112 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 constraints

113 As explained in 2.3, constraint volumes are driven by the difference in zonal generation and demand relative to the transmission capacity. Under Interim Connect and Manage, the rate at which new generation connects will increase without wider increases in transmission capacity, leading to increased volumes of constraint actions and associated costs.

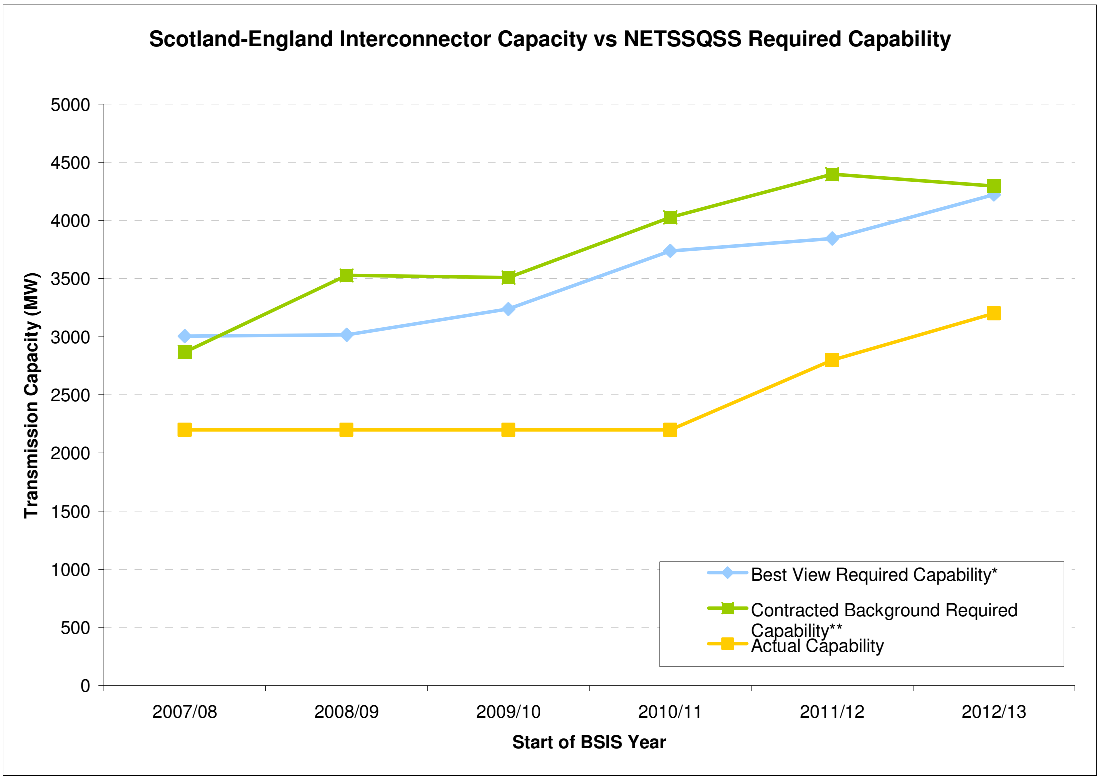

Figure 9: Cheviot Interconnector Capacity Vs NETSSQSS Required Capability

114 Figure 9 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. As the deficit in capacity increases due to new generation connections, the volume of constraint actions will increase, leading to increased constraint costs.

Question 4 – To what extent do you believe that the increase in connected generation behind non-compliant boundaries due to Interim Connect and Manage will impact constraint costs and as such is a key driver?

2.5.3.2 Wind Generation

115 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 9.

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

Table 1: Connected generation capacity in Scotland

116 Due to ROC[20] 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 constraint wind, particularly during periods of low demand with limited conventional plant running.

117 Amongst these challenges presented by the increased volumes of connected wind is the availability of mechanisms to control the output of all wind generators. Efforts are underway to address these issues.

Question 5 – To what extent do you believe the increase in wind generation will impact constraint costs and as such is a key driver?

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

2.6 Summary

118 In this section we have discussed the present incentive scheme, the background to constraint volumes and costs and the make up of constraint costs, highlighting the limited interaction between constraints and other scheme components

119 We have explored the key drivers of costs, namely volume of actions required and the price of these actions. Constraint costs are driven by

- Generation Pattern
- Demand Levels
- System Capacity impacted by outage requirements
- Transmission System Faults
- Price

120 Of these National Grid has limited control over generation dispatch but can manage output in the BM or through bilateral contracts and other services. Working with the respective TOs, National Grid seeks to place outages such that constraint volumes are minimised and liaises with the TOs, to identify capital schemes that either reduce constraint costs or mitigate the risk of constraints occurring. The impact of fault outages and late return of outages are beyond the control of National Grid. However, National Grid can take pre or post fault actions to minimise these costs. National Grid has limited control on the level of demand and on wholesale power price which drives the cost of actions. However, National Grid can minimise constraint costs via the use of, and development of, bi-lateral contracts

121 We have considered recent changes to governance of new connections and the anticipated impact of this on constraint volumes. We are engaged in exploring methods to manage the increased level of generation and increased level of wind penetration.

122 As the level of generation connected behind non-compliant boundaries increases, constraint volumes are expected to increase resulting in an increase in costs of constraint management.

Section 3
Unbundling of Constraint Costs

In this section we discuss the merits of unbundling constraints from other aspects of system operations

3.1 Introduction

123 Some areas of costs under BSIS are closely linked together. These are principally those areas that are related to managing energy over various timescales – Margin, STOR, Energy Balancing, Fast Reserve and Response.

124 Constraint volumes, on the other hand, are more 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. The combined result of this creates constraint costs as detailed in sections 2.4 and 2.5.

3.2 Current Incentive Structure

125 Currently all constraint costs are bundled together with the energy related services and other BSIS cost components. Whereas there is an interaction between the volume of margin actions and export constraint volumes this is non-linear and is comparatively small for the margin pot.

126 A fully bundled scheme has a number of benefits. Where there is interaction between components, costs are allocated via an agreed set of rules but the rules do not impact on the overall incentive performance. A fully bundled scheme is generally easier to monitor and to determine the overall direction of system balancing costs.

127 Equally, there are a number of disadvantages with such a scheme. The bundled scheme cannot easily capture the differing risk profiles for each component cost. Thus combining these in to a single scheme can result in a risk profile that is narrower than appropriate for some areas and too wide for others. As such the balance of risk and reward can be skewed.

128 In addition, a bundled scheme does not support specific focus on one component of concern. It may provide a barrier to longer-term schemes if certain components are not well suited to the development of such schemes.

129 A bundled scheme can result in the overall performance of BSIS masking aspects where the System Operator has made significant savings via prudent operation or development of novel techniques interacting with windfall losses in other areas e.g. a reduction in costs for constraint actions due to prudent contracting strategy being counteracted by an increase in costs for reactive power due to changes in power price.

3.3 Drivers and Risk Profile

130 As discussed in section 2 constraint costs are driven by

- The volume of actions required
- The price of those actions
- The price of replacement actions
- Replacement margin costs

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

- How much generation is self-despatched in to the zone
- How much demand is being consumed in the zone
- What the capacity of the circuits connecting that zone to the rest of the system are

132 As the transmission system is generally constructed such that there is sufficient capacity for all the connected generation to reach the wider market (with a few exceptions such as Cheviot) the main reason for constraint costs to be incurred is the reduction in capacity associated with outages of transmission system equipment.

133 These outages are necessary for the connection of new generation or demand, maintenance of existing equipment or repair to broken equipment and for construction projects to increase transmission capacity. As such the main mitigation is by nesting of multiple pieces of work – thus limiting exposure to the constraint – or by careful placement of the outage to correspond with favourable generation or demand conditions.

134 The final outage plan required to deliver required works for the following financial year is agreed at calendar week 49, thus has an inherent risk of changes to expected generation pattern or generator outages increasing volumes of constraint actions to be required.

135 As the drivers behind constraint costs are different from those underlying the management of energy, notably the seasonal and yearly effects of the planned series of outages in a given timeframe, this creates a different risk profile for constraints when compared with the other BSIS components. Seasonal and yearly effects are discussed further in Section 6.

Question 6 – Do you agree the drivers for constraint costs are significantly different from those of other components of system operation?

3.4 Benefits and drawbacks of unbundling

136 A potential benefit of unbundling constraints is the ability to allow for a scheme designed to properly reflect the risks of this area. It may allow the limitation of windfall gains or losses as well as improving the transparency and promote clarity of National Grid's management of constraints. As noted above, separation of constraints would allow for a scheme designed to properly reflect the risks of this area including the duration over which any target is set.

137 A key benefit of unbundling is the benefits achieved by National Grid in managing other areas of system balancing are not polluted by windfall gains or losses under other components due to drivers outside of National Grid's control. This would improve transparency and promote clarity of the areas on where National Grid is outperforming or underperforming their targets. As noted above, separation of constraints would allow for a scheme designed to properly reflect the risks of this area.

138 The improved clarity of constraint costs would also be of benefit in the future where other potential changes to the industry could influence these costs (notably TAR[21] and Locational BSUoS[22]).

139 One risk of unbundling constraints is where National Grid can manage more than one aspect of system operation via a single action, for example managing constraints and reserve. An example of this would be synchronising a generator in an area that is short of generation. This machine would also provide margin. Currently, although a process exists to allocate costs from this to one of the two "pots" where it sits has no impact on the overall BSIS outcome. The methodology by which actions are allocated therefore would have to be agreed and auditable and ensure that opportunities to play one scheme against the other are negated.

140 Unbundling increases complexity of scheme management and may divert resources from areas that may add most value to the industry. The considered development of the unbundled schemes should remove this concern.

Question 7 – Are there any additional benefits or drawbacks in the development and implementation of an unbundled incentive?

[21] http://www.decc.gov.uk/en/content/cms/consultations/improving_grid/improving_grid.aspx
[22] http://www.nationalgrid.com/uk/Electricity/Charges/modifications/uscmc/

3.5 Options

141 To better target the incentive, an option could be to unbundle constraint costs from the energy management actions and the remaining components (reactive power, transmission losses and black start).

142 In order to successfully unbundle constraint costs an agreed methodology by which the volumes and costs of managing constraints can be defined and separated from the other costs of system operation is necessary.

143 The development of this methodology could be based on existing (or soon to be existing processes) such as the P217[23] constraint flagging or the existing National Grid internal methodology known as the BAAR[24] process. It is also important that any methodology is compatible with those under consideration in other areas such as TAR and Locational BSUoS.

3.6 Identifying Constraint Actions

144 The first stage of identifying constraint costs is to determine what actions were undertaken in the management of constraints.

145 P217 flags are to be introduced from November 2009 for the purpose of separating actions from those taken for purely system reasons – constraints in other words – from those involved in residual energy balancing. These flags will be set in control timescales and not revisited after the event.

146 "BAAR" tagging is the process used internally within National Grid to identify constraint actions and their corresponding costs. Under this process an engineer will assess information from various records made by our Control Room against the actions taken in a half-hour period. This allows a comparison to be made of the indicated volume of constraints pre-event with the actual volume of actions taken and an appropriate volume marked as being for a constraint. More information on the process by which actions are recorded as being for constraint resolution can be found in the Appendix.

147 The major difference between these two methods comes from occasions where an action would have been taken regardless as to if the constraint was active or not. Under the P217 rules as the action affects an active transmission system constraint it is flagged as a system action. The "BAAR" tagging process would recognise that the costs incurred are not a result of an active transmission system constraint, although maybe has resolved it, effectively for free.

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

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

148 Both methods provide a reasonably accurate reflection of constraint actions. The choice of method comes down to one of which method is preferred. As the “BAAR” tagging method – which is essentially the same as that used for the Income Adjusting Event claim of 2005/6 – is the method used internally we suggest that this is preferable. Conversely the consistency with P217 flags – which will be visible on BMRA – makes for a more transparent process.

149 In both cases the method relies on National Grid to identify and record that the action is for a constraint rather than some alternative reason. This is currently the position with regards to both the proposed P217 tags and constraint costs as currently reported by National Grid.

150 In agreeing a methodology, some formal agreement of methodology must be reached, with the same methodology being used for determining the forecast costs and the outturn costs in order to provide consistency across all areas where these costs are reported.

Question 8 – Please provide your views on the methodologies described? Is there an alternative methodology which should be developed?

3.7 Summary

151 The current structure of the Balancing Services Incentive Scheme covers all of the costs of system operation and as such any one area can mask benefits delivered elsewhere. The inclusion of constraints in a bundled scheme also means that the risk profile of the scheme has to consider a wide range of issues that may present inappropriate levels of incentivisation overall.

152 Unbundling of constraints from other aspects of system operation would allow for suitable levels of reward representing the risks of that aspect. This would also limit the opportunities for windfall gains or losses to affect the total performance of the scheme whilst providing transparency of the costs in all areas. This transparency may lead to new incentives in other areas, such as shared SO/TO schemes.

153 In order to unbundle constraints from other areas an agreed method of identifying and separating these costs from those in other areas will be needed. In addition, separate schemes create additional complexity in terms of monitoring and managing the different aspects of the scheme. Division of the schemes also requires careful design so that untoward incentives are not created to play one scheme off against another.

Section 4
Scheme Adjustments

This section considers options for the development of an adjustment term or terms that would update the constraint cost incentive dependant on key drivers. We also highlight what advantages or disadvantages this may bring.

4.1 Introduction

154 As discussed in earlier sections, there are various drivers that influence the overall costs of constraints. These are:

- The volume of actions required
- The price of those actions
- The price of replacement actions
- Costs for the replacement of margin

155 As shown, a number of these key drivers are to different extents outside the control of National Grid.

156 Having identified that these are drivers of the costs of managing system constraints then it follows that any variation in these factors will impact on the level of constraint costs incurred.

4.2 Current Incentive Structure & Drivers

157 National Grid forecast a cost for constraints as part of the process in agreeing an overall BSIS target for the year. This forecast will, at a high level, consider:

- The planned outages and subsequent reduction in transmission system capability
- Take a view of the likely output of generation and demand behind the constraint boundary
- Estimate the difference in price between the Bids and Offers needed to manage the constraint, the potential contract/trading strategy efficiencies and the use of intertrips and their associated prices.

158 Changes to any of these assumptions through, for example, changes to generation output or transmission outages can lead to windfall gains or losses for National Grid.

4.3 Opportunities for Adjustments

159 In developing a forecast of constraint costs certain assumptions have to be made based on the available information. Between the yearly constraint cost being derived and the time that these constraint(s) occur, various factors will lead to conditions being different from these initial assumptions. Some of these changes can be influenced by National Grid. For those drivers that are outside the control of National Grid, there is the potential for windfall gains and losses that could result in actual outturns being different from those forecast e.g. a change in the output of a generator resulting in the reduction in constraint costs.

160 The development of a robust adjustment methodology that could change the constraint cost target depending on the change in a key assumption would reduce the potential for windfall gains and losses and ensure that National Grid focus attention on deriving value from the management of the drivers within its control.

161 The two main areas for the development of an adjustment are constraint price and constraint volume. Below we outline four potential options that could be considered either individually or together to develop a methodology for updating the constraint cost forecast in line with changes to key assumptions.

- Price adjustment
  - Bid / Offer price spread
- Volume adjustment
  - Volume of new generation connecting
  - Volume of generation behind derogated boundaries
  - Number of outage weeks on circuits across key boundaries

4.3.1 Bid/Offer spread

162 One of the key factors involved in calculating the cost of a constraint is the price of actions taken to resolve the constraint. As set out in section 2.1.1, the difference between the constraint resolving action and the replacement energy or margin action results in a constraint price. In simple terms this is the difference between the Bids and Offers needed to manage the constraint. In addition, Figure 8 shows how the spread between Bid and Offer prices varied historically with changes in wholesale price.

163 One way of removing the potential for windfall gains or losses from National Grid's incentive scheme would be to include a factor within the incentive that adjusts the constraint cost forecast for the changes in the Bid and Offer price spread away from those used in the original forecast.

164 For instance, if the spread between Bids and Offers decreases from those used in the original forecast, the constraint cost target would be reduced:

Revised constraint target = Original target x adjustment factor

Adjustment factor is calculated using the forecast Bid / Offer spread and the actual Bid / Offer spread

165 An assessment of the relationship between the change in Bid / Offer spreads and the constraint costs would be required to develop an adjustment factor.

166 The introduction of such an adjustment would negate the impact of price changes due to external factors, reducing the likelihood of windfall gains and losses for price drivers outside the control of National Grid.

167 As with any adjustment term careful development will be needed such that suitable incentive remains both as an upside and a downside. For instance an incentive based on accepted bids and offers may perversely alter the risk profile when considering more innovative methods outside of the Balancing Mechanism that may hedge such changes in Bids and Offers such as managing constraints via constraint contracts or intertrips. Since such innovation is exactly what an incentive is trying to encourage, potentially an adjustment should follow significant price trends but not exact changes.

4.3.2 Volume of generation connected

168 With the introduction of Interim Connect & Manage (ICM) in May 2009 the capacity of generation connected at certain parts of the network may increase beyond that anticipated at the time the incentive scheme was agreed. This is particularly the case for schemes that are in excess of one year in duration. Indeed in addition to ICM, we have recently seen fairly significant changes to the expected connection date of generation in the short-term (i.e. delays to connection dates).

169 This newly connected generation will exacerbate any constraints affecting that part of the network from the time they begin generating. This is particularly the case where there is already a high concentration of generation and transmission capacity is already limited, such as at the Cheviot boundary or around the Thames Estuary. This will increase the volume of constrained generation and so increase the volume of actions required to manage the constraint, resulting in increased costs. When developing the constraint cost target, the volume of such generation connecting to the system may be uncertain, therefore, assumptions could lead to windfall gains and losses depending on the actual level of generation that connects.

170 One option to manage the uncertain level of generation connecting is to include an adjustment term within the incentive scheme. This adjustment would realign the incentive to the actual level of Connections connected generation.

171 The adjustment would increase the constraint cost forecast with the changes in newly connected generation. At a high level, one way that this could work is:

Adjusted forecast = Original forecast + Adjustment for Connections

Where
Adjustment for Connections = Cost adjustment x volume

Where
Cost adjustment = £Xm per 100MW of connected generation.

172 Without such an adjustment term, an assessment of the volume of generation that is likely to connect will need to be made. Such an assumption will have an effect on the risk profile, resulting in the potential for increased chance of windfall gains or losses or the need for low sharing factors, caps and collars for the incentive scheme.

173 However, the adjustment accuracy relies on the assumed costs for new generation matching the actual costs. If the adjustment does not accurately reflect the actual constraint costs, there remains a potential for some windfall gains and losses.

4.3.3 Volume of generation behind derogated non-compliant boundaries

174 This would be similar in principle to the outlined option above. This option would cover all generation capacity where that generation is behind a boundary that has been designated as non-compliant with the NETSSQSS and derogation issued.

175 Any new connection behind the relevant boundary would be covered as would any boundaries derogated from compliance with the NETSSQSS after the scheme has been agreed.

176 On a non-complaint derogated boundary constraints costs are significantly higher and therefore this form of adjustment would allow for more accurate representation of the cost risk from additional generation connecting behind such a boundary.

177 Accurately assessing the impact of a boundary becoming non-compliant presents a difficulty in terms of developing a suitable adjustment term, particularly in a world where there may multiple boundaries that have to be considered and complex interactions between them.

4.3.4 Number of outage weeks on planning boundaries

178 One of the drivers of constraint costs is the number and location of outages, especially outages on critical boundaries. Although the outages are planned, a number of these outages may change throughout the year, e.g. extending or cancelling outages due to unforeseen complications or reducing outages due to deferment to the next year.

179 As these outage changes would not be known when the scheme was agreed, the costs of these additional outages would not be included in the scheme target and as such may have a detrimental effect on other aspects of the outage plan as the system operator looks to trade costs initially allocated to other outages to the delayed circuit.

180 A method of adjusting the constraint cost target for these changes would better reflect the actual constraint volumes imposed by system outages. A base level of outage weeks per boundary could be set and a cost forecast for boundary outage per day.

181 A similar proposal was suggested for implementation in the 2008/9 scheme, considering only the Cheviot boundary. Such an adjustment would still place a strong incentive to reduce costs below the adjustment level but arguably may weaken the incentive to work with the TOs to find innovative methods of reducing the number of outage weeks. A potential solution to this issue is to develop a method of adjusting the scheme target that is asymmetrical and so provides a greater adjustment for reductions to the number outage weeks than it does for increases in the number of outage weeks.

Question 9 – Do you agree it would be appropriate to have an adjustment term to mitigate National Grid's exposure to uncontrollable and unpredictable risks affecting constraint costs?

Question 10 - What items do you believe it would be appropriate for an adjustment term to cover and how would these work?

4.4 Benefits of an adjustment term

182 Inclusion of a term to adjust the incentive scheme for factors which influence constraint costs allows for a scheme that reflects the risks of areas outside of National Grid's direct control and promotes a focus on the areas that National Grid can influence.

183 A suitable adjustment term would also be a key factor in agreeing longer term schemes in order to control for the prospect of windfall gains or losses due to uncertainty in the parameters used to agree such a long term scheme.

184 An adjustment term would minimise the need for National Grid to seek an amendment to the incentive scheme target via an income adjusting event [IAE] (IAEs are further described in section 5.6).

185 Finally, and as in other areas, inclusion of an adjustment term promotes transparency of the benefits delivered by National Grid or if there are areas that are not being as well managed and these areas addressed or rewarded appropriately.

4.5 Summary

186 In the section we have considered the opportunity for development of adjustments to the constraint target, focusing on key drivers beyond National Grid's control, the cost of actions to resolve a constraint and the volume of generation connections which were not planned at scheme start date.

187 Options for adjustment factors were presented, looking at Bid/Offer Spread, the volume of generation connected through Interim Connect and Manage or connected behind a derogated non-compliant boundary. We have also explored an option to adjust the target dependent on the number of outage weeks on planning boundaries

188 Any adjustment target would require careful development to ensure suitable incentive remains and does not perversely remove incentives to innovate or find ways of 'hedging' costs. It would also better reflect the risk of areas beyond National Grid's direct control and provide greater clarity of benefits delivered by National Grid, unpolluted by windfall gains or losses.

Section 5
Treatment of Fault Outages

This section discusses the specific issues associated with management of fault outages and considers alternative treatment of costs of constraints resulting from such outages.

5.1 Introduction

189 Within this section we consider the way in which the costs incurred due to the management of fault outages are treated under the Balancing Services Incentive Scheme (BSIS).

190 Alternatives to the current treatments of these costs are considered along with the benefits and/or drawbacks of each.

5.2 Transmission System Faults

191 On occasions Transmission Owner equipment experiences problems that require it be disconnected from the remainder of the transmission system. This can be either by automatic operation of protection equipment or by intervention of System Operation engineers. Such an advent would leave no option other than to accept the outage of the circuit until it is deemed fit to return to service. This is called a fault outage.

192 Fault outages can occur due to:

- weather related incidents, such as lightning
- third party damage, such as the digging up of cables
- equipment failure

193 Depending on the level of damage to transmission system equipment, a fault outage can be short resulting in minimum disruption or can be for significant length of time until the equipment is replaced.

194 As discussed in Section 2, when these faults occur, as with any other system outage, there is a reduction in the ability of the system to transfer energy and this may result in the need for the actions to be taken to manage these flows.

5.3 Costs of Fault Outages

195 The chart below shows the monthly costs of constraints caused by faults since BETTA go-live in April 2005.

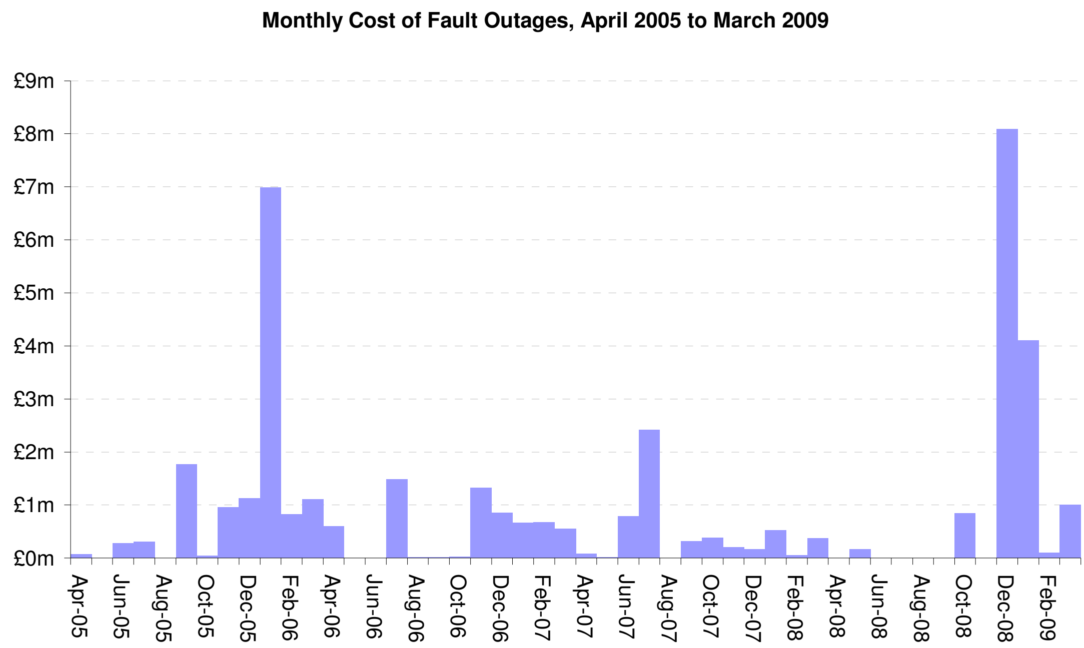

Figure 10: Monthly Costs of Fault Outages since BETTA Go-Live

196 As can be seen in the above chart, constraint costs as a result of fault outages, normally, take place over the winter months when the system is more highly loaded. In addition, the costs incurred due to fault outages are normally under £1m in any given month. Notable exceptions to this typical level of costs are:

- A fault on the Cheviot boundary January 2006
- The failure of a transformer attached to a key circuit and flooding in Yorkshire and south-west England in June and July 2007
- Cheviot constraint costs and the failure of a separate quadrature booster in December and January 2008/9

197 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. The costs of managing such events are not currently included in the incentive scheme and therefore can significantly impact on the scheme outturn. In addition, no provision is included for the costs associated with a system to generation tripping scheme firing.

198 Although the timing when a fault will occur can not be explicitly predicted to any degree of accuracy. It is however possible to evaluate what the impact of a given fault outage might be given assumptions about generation and demand disposition and look at what the level of costs

have been incurred in the past for the same or similar outages. It is also possible to evaluate the costs of a given outage after the event.

199 The unpredictable nature of fault outages can result in significant cost being incurred as the outage have not been subject to the normal planning process. In addition, any costs incurred due to fault outages are in addition to the costs on which National Grid is incentivised and therefore generally leads to windfall losses.

200 These costs can constitute a significant proportion of the total constraints costs incurred in any given year. To date these have been absorbed within the bundled incentive scheme.

201 Some agreed method by which these costs can be better separated from the costs for planned outages may be preferable, that limits the impact on the overall incentive and improves the clarity of drivers of constraint costs. This may also present opportunities for changes to the methods by which National Grid and other parties are incentivised.

5.4 Specific Drivers of Fault Outages

202 The factors that influence the cost of fault outages are the same as for planned outages and are discussed in detail in Section 2 e.g.

- The volume of actions required
- The price of those actions
- The price of replacement actions
- Replacement margin costs

203 However, due to the nature of a fault, various additional factors come in to play that may make a fault outage more onerous than the same outage would have been if it had gone through the normal planning and placement processes.

204 Such factors that may be experienced for a fault outage but not a planned outage are:

- The outage can not be placed to align with times of low demand or generation thus exposing the System Operator to the conditions on the system at the time the fault occurs

- The type of failure e.g. disruptive failure that requires complete replacement of the failed item will take longer than repairing an existing item.

- Lack of replacement equipment available to the TO – some items may have long lead times required to manufacture and deliver a replacement. This is particularly an issue for specialised equipment or items that are very much in demand around the world. For a planned outage these would be ordered in advance and the work arranged for a time when the item would be available.

- Availability of TO staff and/or contractors to carry out the repair work. This may require halting work on other outages, waiting for them to become available or paying a premium to gain access to them earlier. Again, planned outages would allow for the resources that could be brought to bear and so have this resource in place.

- Limited time for negotiation over commercial terms or development of alternative Balancing Service products to mitigate the costs relative to the Balancing Mechanism

- Unfavourable nesting of outages – the fault outage may interact with a planned outage that would not normally be allowed to coincide. The unfavourable outage pattern may greatly exacerbate the constrained volumes and hence increase costs

205 These factors can all increase the time that the transmission system is exposed to the constraint and hence the volume of constraint actions required will be increased. The majority of these aspects are those led by the Transmission Owner whose equipment has failed. However, the System Operator can exert some influence to encourage the TO to consider other options, such as reprioritising resources to the fault at the expense of another outage.

5.5 System Operator Control of fault outage costs

206 As System Operator, National Grid has various tools available to limit the exposure to the costs of managing fault outages.

207 The majority of these are the same as for any outage e.g. novel system configurations to reduce volumes, economic use of the Balancing Mechanism or alternatives such as Trading.

208 Requesting that the Transmission Owner takes the fault outage at another time is infeasible as there is no choice when the circuit begins its outage. However, the System Operator can provide additional funding to the Transmission Owner in some areas to pay for different working practises, for example, to decrease the time between the fault and return to service of the affected circuit. This facility exists for both planned and fault outages; however, this may have to be assessed against a delay or cancellation of other work.

209 National Grid may also seek to agree a bilateral contract with parties who can influence the volume of action or price of managing the constraint. However, given the lack of lead time for a fault outage, and the general unknown return to service time, this route may not be feasible due to there being insufficient time to tender for or negotiate the terms of the contract.

210 National Grid has also sought to develop new Balancing Services as a method for managing constraint costs in the past. The rapid and unannounced introduction of a fault outage prohibits the development of a specific service in response to a fault occurring on account of the lead times required to develop, negotiate and agree the service with the industry and introduce any code modifications required.

211 Conversely, many existing Balancing Services are in place that can be used as an economic mitigation for both planned and fault outages. An example of this would be a commercial inter-trip service with generation or demand within the affected constraint group, should one exist.

212 Should such an event occur this in turn will create an unexpected increase in BSUoS costs and, if significant, National Grid may seek to claim seek an amendment to the incentive scheme target via an income adjusting event.

5.6 Options to improve the incentivisation of fault outage costs

213 Some suggested options for treating fault outages are:

- Raising Income Adjusting Events where the costs of a fault outage exceed a pre-determined threshold amount
- A pre-agreed level of compensation for fault outage of specified key circuits
- A level of costs spread over multiple incentive years

5.6.1 Option 1 – Income Adjusting Events

214 The structure of the Balancing Services Incentive Scheme contains provision for Income Adjusting Events (IAE) to raised where an event, be it a fault outage or otherwise, causes a change to the costs incurred by the System Operator that:

- Exceeds a threshold amount (currently £2m)
- Was not foreseen in agreeing the scheme target

215 The overall process for raising an Income Adjusting Event is set out in National Grid's Transmission Licence. National Grid and other Parties as set out in the BSC may raise an IAE to the Authority. Supporting evidence of the costs and/or expenses have been incurred or saved must be provided.

216 Raising an Income Adjusting Event for any significant fault outage, or collectively for all fault outages throughout the scheme, would see National Grid provide evidence that the management of the outage was efficient and economic at the end of the scheme. If this accepted then the incentive scheme target would be adjusted by the agreed amount, or accepted proportion thereof, thus removing National Grid's exposure to these costs. Overall cost to the industry would be unchanged except for any changes to National Grid's profit or loss under the scheme as the costs incurred have already been recovered via BSUoS less the effects of the BSIS sharing factors.

217 This method creates uncertainty as to the overall position of the scheme until such time as the IAE has been raised and agreed as well as the overheads of creating and reviewing any IAEs that are raised.

5.6.2 Option 2 – Pre-Agreed Circuit Compensation

218 Under this option National Grid, Ofgem and the industry would agree a level of compensation, along with possible adjustment for power prices and market length, which would be paid per day of fault outage on specified circuits.

219 For example, a cost for an outage for a specific circuit would be calculated, giving a cost of £Xm per outage day against a set Bid/Offer spread. Post event, an adjustment would be made to the target for the constraint component of the incentive scheme to account for the agreed compensation amount, adjusted for changes to Bid/Offer spread. National Grid would retain a percentage of savings with the remainder passed back to the industry via BSUoS.

220 Thus National Grid would be incentivised to secure a lower volume at a lower price than the established baseline cost for this outage thus maintaining incentivisation whilst not being exposed to potential large windfall losses due to unforeseeable events.

221 Further adjustment could be developed on the level of installed capacity that an outage would affect as this may change the volume of constraint that would be incurred.

222 This method would place a significant burden on calculating the costs that an outage of one of these key circuits is likely to incur in the event of a fault. This becomes more onerous as more circuits are included and the possibility that combinations of outages become involved.

223 As the pre-agreed circuit costs do not reflect actual constraint costs incurred, there is a risk of windfall gains or losses from the agreed compensation if the assumed parameters used in setting the allowance are radically different at the time the fault occurs. This may also create perverse incentives with regards to the return of the circuit should costs be lower than agreed.

5.6.3 Option 3 – Average Compensation

224 By their very nature fault outages are unpredictable. Therefore forecasting the impact they could have on a given year will not exclude the potential for an exceptional number of faults – or a single high cost event – outside the forecast average in any given year.

225 To provide a forecast for the costs of fault outages that could occur over a period of several years one option could be to include provision for a fault constraint cost target. Considering Figure 10, implementing a target of £12m/year for fault outages over the duration shown would have increased the constraint cost forecast by a total of £48m with just under £50m of constraint costs being incurred.

226 However, as this allowed cost would be subject to the incentive scheme in place in each of those years the net impact to National Grid would have been altered by the sharing factors in place for each respective scheme and as such may not reflect the impact that the increased Incentivised Balancing Costs (IBC) has had over the entire duration.

227 In addition, this methodology suggests that the future impact of fault outages will be the same as it has been historically. This may not be true due to the changing nature of the transmission system, such as the connection of more generation prior to system reinforcements under the Interim Connect and Manage arrangements, which have the potential to drive up constraint costs and could impact significantly on fault outages.

228 Such an average cost recovery method obviously carries with it risks of under or over recovery in short timescales. As such an average recovery method is best placed with a long term scheme to ensure that the costs recovered over the duration of the scheme are appropriate to the level of constraint costs experienced over the same period.

229 The introduction of such a methodology would have the benefit of incentivising National Grid to minimise the cost of the fault outage.

5.6.4 Option 4 – "Insurance Pot"

230 A similar method by which the risks of fault outages can be mitigated could be to set up a separate fund into which market participants would pay a fee. In the event of a fault outage incurring significant costs these could then be recompensed from this fund.

231 As the fee paid by industry participants would be a set fee per year this would give a certainty of costs albeit at a rate that exceeds the costs of faults in a given year.

232 There are a number of considerations that need to be addressed when developing such an option:

- Level of insurance
- Incentive on National Grid to reduce the impact of the fault outage
- What happens if the insurance is in surplus or deficit at the end of the period?
- Who pays and at what level?
- Interaction with BSUoS
- Benefits to the industry

233 Depending on the specifics of how this fee was set could also present problems for smaller participants.

234 Given the magnitude of costs that can be incurred there would likely be a delay in this fund reaching a sufficient magnitude to cover all conceivable faults. This risk would need to be covered, either by National Grid or the industry as a whole, until such time as the fund matures.

Question 11 – Please provide your views on the development of an alternative method to manage constraint costs due to fault outages? Is there an additional method which should be developed?

5.7 Benefits and drawbacks of alternative treatments of fault outages

235 Fault outages, by their nature, are unpredictable and have a limited number of controllable factors and options for the management of the costs involved. As no allowance is currently made for fault outages within the agreed scheme this presents a high risk of windfall losses being incurred as a result of factors which by their nature can not be controlled. A separate scheme would remove the risk of windfall losses.

236 In some circumstance the change in scheme outturn due to transmission system faults can be significant enough to effectively remove incentivisation from other areas. The overall outturn can be pushed to such a level that a recovery to a position where any impact on costs is reflected in the profit or loss that National Grid can make on the scheme is not feasible

237 Separating these costs from other aspects of system operation would therefore improve transparency of the costs involved as a result of fault outages, which may provide a mechanism for other incentives to be created.

238 Separation of fault outages from other constraint costs also allows for the risks of fault outages to be properly reflected without contaminating other areas.

239 In order to separate fault outages a methodology for correctly identifying actions as 'Fault' or 'Planned' will need to be developed, this itself brings potential complexity and the risk of untoward incentives to balance one scheme against another.

Question 12 – Do you agree that development of an alternative treatment for fault outages is appropriate?

5.8 Summary

240 In this section we have looked at the treatment of fault outages and ways is which they could be treated in the future as well as considering the benefits and drawbacks of each proposal.

241 Options for alternative treatment of outages are presented with potential benefits and drawbacks. In general separate treatment of fault outages from other incentivised costs reduces the risk of windfall losses arising from fault outages whilst providing transparency of the costs incurred.

242 However, some of the proposals here would create uncertainty as to the final position of the incentive scheme and/or present difficulties in agreeing suitable targets or levels of compensation.

Section 6
Scheme Duration

This section considers the duration of the current incentive scheme and considers the rationale for remaining with a yearly incentive or moving to a scheme of a different duration.

6.1 Introduction

243 In this section we explore the options and rationale for moving away from the current single year incentive structure.

6.2 Current Incentive Structure

244 Under the current structure of BSIS Constraint costs are a part of the single bundled scheme for one year.

245 The current arrangement has a forecast for constraint costs developed in the January prior to the start of the scheme in April. The forecast includes the expected bid / offer spread (partly based on forecast power price), forecast for the volumes of expected generation, demand forecast and constraint boundary capability (utilising planned outage data).

246 Variations in forecast can occur for unexpected changes in bid / offer spreads, demand levels, generation output or outage pattern. For example, constraint costs in 2008/09 greatly exceeded the forecast due to increase in volumes and prices caused by a number of significant fault outages, outage extensions and higher Bid/Offer spreads than forecast. The level of the increase in constraints resulted in National Grid effectively being un-incentivised for a large part of the year.

6.3 Alternative Scheme Durations

247 There are various options for scheme duration that could be considered. A change in incentive duration could allow for improved representation of the costs for managing system constraints and/or provide increased focus on driving down costs over the longer term and better manage the potential for windfall gains and losses.

6.3.1 One year scheme

248 One option is to retain the current one year scheme. This allows for a balance of relatively up to date information on the major works planned for that year along with wholesale prices from which Bid/Offer prices can be estimated.

249 The implementation of such a scheme would have the benefit of being familiar and the current processes involved in developing the forecast are well established.

250 However, as shown in previous consultations there is considerable variability in power prices in the timescales from which a target is agreed to when the costs are incurred and the potential variation in generation pattern across the year.

251 Likewise, the one year scheme is exposed to variations in the outage plan that can occur due to unforeseen events such as generation outages moving, fault outages or outage extensions.

252 National Grid is not able to directly influence these risks and so can led to potential windfall gains or losses. A potential improvement to the present one year scheme is the inclusion of suitable adjustments for drivers outside of National Grid's control.

253 A one year scheme offers clear incentivisation to manage constraint costs within year but ultimately may lead to a focus on the present year and remove incentives to consider the way constraints are managed in the longer-term, with no financial incentive to optimise constraints across multiple years.

6.3.2 Seasonal Schemes

254 As discussed previously there are seasonal effects within the costs of managing constraints be it from demand levels within an area or from the outage plan being targeted to the summer where lower capacity is needed to meet peak demand.

255 Therefore, one option would be to reduce the current incentive length so that there is a seasonal incentive target. This scheme would recognise that there are different drivers for constraint costs in summer, where they are mainly planned outage driven, and winter where constraint costs are due to an inherent lack of transmission capacity or fault outages.

256 This suggests that a scheme that mirrors the outage season may better reflect the differing seasonal risk profiles. In addition, the shorter the scheme duration, the more accurate the forecast assumptions such as power price.

257 Shorter schemes would also minimise the risk of large changes in costs due to fault outages or changes in generation behaviour resulting in the incentive hitting the cap or collar resulting in National Grid being un-incentivised over long periods

258 On the downside agreeing a number of schemes in each year places an additional overhead in forecasting and agreeing those costs as well as reducing the certainty over the resulting charges in the medium term. . In addition it may provide perverse incentives to move outages between seasons where targets are close to caps or collars.

259 The shorter schemes would also focus attention on driving costs down in the short term and reducing the impact of longer term actions that could reduce costs.

6.3.3 Multi Year scheme

260 As mentioned above, there are a number of drivers that drive constraint costs for the one year scheme. These drivers are exacerbated for schemes of a longer duration, such as unknown outage plans for two years ahead, increased volatility in generation patterns and wholesale power prices longer. Therefore a longer term scheme could increase the likelihood of windfall gains or losses. As such, a method of reducing this risk could be developed. As mentioned in section 4, suitable adjustments could be developed that would update the constraint cost target in line with changes to the key drivers

261 A multi-year scheme with annual targets does provide an increased focus in potential longer-term initiatives that may reduce the overall costs of managing an outage. This may include

- increased resources to manage the co-ordination of outages with the TOs over a number of years
- allow longer term, more economic contracts to be entered into with generators to manage output
- advance appropriate system reinforcement works that require a longer term payback period
- focus attention on optimising the outage plan over multiple years

262 It is worth noting that at present 15% of any additional internal costs over the agreed level are paid for by National Grid via the SO internal cost incentive scheme that is set for five years (in line with the price control timescales). Therefore any increase in resources (an internal incentive cost) used to drive down external balancing costs would be paid for by the SO over the longer-term, whilst the external scheme is set annually and therefore any incentive benefit created by the additional resource may be lost after one year once the external incentive target is reviewed and reset. .A longer-term external incentive scheme would therefore better align the internal and external incentive schemes and remove any perverse incentive to avoid increasing internal costs in the longer-term to drive down external costs.

263 The multi-year scheme would have annual agreed targets that may be adjusted for the key drivers identified earlier. Therefore a multi-year scheme would give an indication of the level of costs expected over the

duration of the scheme, and hence their contribution to BSUoS whilst the removal of a need to agree a target each year would reduce the overheads involved in that task.

264 Estimating the potential efficiencies that can be gained by increasing the focus on longer term cost reduction is not currently known. However, in line with appropriately aligned SO and TO incentives on driving down costs, we believe that there is some scope for driving down costs due to improved processes, across multiple years. However, this needs to be weighed against the potential increase in risks that accompany longer term schemes.

Question 13 – Do you believe there are benefits in the implementation of a longer than one year scheme? Please describe your views on the optimal incentive duration for constraints.

6.4 Summary

265 In this section we have presented three options for scheme duration; considering retention of the current one year scheme; extension to a multiyear scheme or moving to a shorter seasonal scheme. We seek industry views on the most appropriate length for the constraint component of the incentive scheme.

266 There a number of benefits and drawbacks for each option. However, the development of longer term schemes and the continuation of the current scheme duration rely on the development of suitable adjustments that update the constraint cost target with changes in the main drivers.

Section 7
Summary

7.1 Summary

267 National Grid is incentivised to balance the system in a safe, efficient, economic and co-ordinated manner. The application of financial incentives enables National Grid to invest in systems and resources to ensure balancing costs and risks are economically and efficiently managed.

268 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.

269 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.

270 This consultation considers development options to the incentive scheme, focusing on the constraint cost component. It considers the driver of constraint costs, potential adjustment factors, appropriate treatment of fault outages and optimal scheme duration and unbundling the constraint component from the remainder of BSIS.

271 Section 2 discusses the present incentive scheme, background to constraint volumes and costs and sets out the drivers behind these.

272 Section 3 discusses options for unbundling constraint costs from other areas of BSIS to create a separate incentive covering constraint costs.

273 Such a separate scheme may include adjustment terms to maintain appropriate levels of incentivisation with changes in drivers that are beyond the control of the System Operator. This is discussed in section 4 along with the benefits or not of such options.

274 Section 5 looks at the impacts that fault outages can have why these differ from planned outages. This section also considers some methods by which these could be treated in any scheme design e.g. separate unbundled incentives for both planned and fault outages, combined incentives for planned and fault outages but unbundled for other areas of BSIS etc.

275 As well as the potential for unbundling constraints from other aspects of BSIS and alternative treatments, Section 6 considers the duration of incentive schemes in relation to constraint costs and presents some views on both longer term and shorter term options.

276 Input from the industry is important in the development of incentive proposals. Therefore, we would welcome any feedback from the industry on the content of this consultation.

Question 14 – Do you have any comments regarding this consultation process?

Section 8
List of Questions

This section lists the consultation questions from the document.

8.1 Consultation Questions

277 The questions below have been constructed to help us determine the industries view on the potential for alternative treatment of the constraint component of system balancing costs.

278 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.

279 The questions are not an exhaustive; if you have any further points you would like to raise please do so.

8.2 List of Consultation Questions

1	Do you believe that the drivers for the volume of generation have been identified? How much control do you believe National Grid has on volumes?
2	Have all cost drivers been captured and correctly identified as being within or outside National Grid control?
3	Do you consider that there are elements within these cost drivers that are within National Grid control? What are these and how do you believe these should be considered in the future?
4	To what extent do you believe that the increase in connected generation behind non-compliant boundaries due to Interim Connect and Manage will impact constraint costs and as such is a key driver
5	To what extent do you believe the increase in wind generation will impact constraint costs and as such is a key driver?
6	Do you agree the drivers for constraint costs are significantly different from those of other components of system operation?
7	Are there any additional benefits or drawbacks in the development and implementation of an unbundled incentive?
8	Please provide your views on the methodologies described? Is there an alternative methodology which should be developed?
9	Do you agree that it would be appropriate to have an adjustment term to mitigate National Grid's exposure to uncontrollable and unpredictable risks affecting constraint costs?
10	What items that you believe it would be appropriate for any adjustment term to cover and how would these work?
11	Please provide your views on the development of an alternative method to manage constraint costs due to fault outages? Is there an additional method which should be developed?
12	Do you agree that development of an alternative treatment for fault outages is appropriate?
13	Do you believe there are benefits in the implementation of a longer than one year scheme? Please describe your views on the optimal incentive duration for constraints.
14	Do you have any comments regarding this consultation process? - Document structure - Overall content and level of information provided - Process

Section 9
Contact Information

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

Appendix A

A.1 BAAR Methodology for Identifying Constraint Actions and Capturing their Price and Volume

The resolution of constraints can cause additional or alternative balancing actions to be taken to achieve total system balance in the most efficient manner. These constraint actions are identified through a detailed monitoring process:

- For actions taken in the Balancing Mechanism, a combination of daily meetings with control and planning staff, along with internal documentation, are used to identify constraint actions
- For actions taken or initiated in the forward planning stage, we have captured and reviewed the decision making, ahead-of-time planning and optimisation process, to identify constraint actions taken ahead of control timescales.

This process, as a whole, allows identification of those specific actions driven by a given constraints and those taken for other operational reasons.

This process captures all relevant details for each action including:

- Price and volume
- Time period of action
- Reason for action
- Physical constraint to which the action is linked

For example, in the case of BM actions, the information captured includes all BOA data.

The identified actions are then formally reviewed after the event by control room, planning and support staff to ensure accuracy. This method allows for checks to be carried out and decisions on the identification of particular actions to be reviewed. The outturn data can then be amended as necessary to achieve an accurate post-event record of constraint action.