Consultation
Document 1/09

# National Grid Electricity Transmission System Operator Incentives for 1 April 2010

## Consultation on the Development of Incentives for Reactive Power, Transmission Losses and Black Start

Version 1.0

**Issued 4 August 2009**

**Responses requested by 2 September 2009**

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# 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.

This document is one such consultation and sets out our thought on the development of appropriate incentives for reactive power, transmission losses and black start. The aim of the document is to present and seek views from the industry how incentives for each of these components could be 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:

**Reactive Power**

- We seek views on the appropriateness of the development of a multi-year scheme and how the implementation of a reactive power index may facilitate this. Also, we ask whether a separate unbundled reactive power incentive would benefit the industry.

**Transmission Losses**

- We seek views on the level of control the SO has over transmission losses and whether it is appropriate that the SO is incentivised in the current manner. In addition we outline potential alternative incentive methodologies that could be developed.

**Black Start**

- We highlight changes in the next 2 – 5 years to Black Start provision and the associated increase in costs. We seek industry views on development of an incentive methodology against a changing generation background.

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

**by 5pm on 2 September 2009**



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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

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

2. 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.

3. 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.

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

5. Via an open letter, published on 28 May 2009[1], Ofgem has asked National Grid to lead on the development of initial proposals for the implementation of System Operator (SO) incentives commencing April 2010. The letter summarises Ofgem's views on the objectives, process and timetable for this year's process and topics for this year's consultation. National Grid's response to this letter can be found on the National Grid website[2].

6. In its 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, National Grid has presented at a number of

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[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

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]

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

8. 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. National Grid will be issuing three independent mini consultation documents this summer on the development of SO incentives; 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 |

9. 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 indexation and the suitability or otherwise of 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.

10. These three consultations cover the majority of Balancing Service Use of System (BSUoS) costs. This consultation addresses the costs for reactive power, transmission losses and black start that account for approximately 7% of the BSUoS total costs.

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

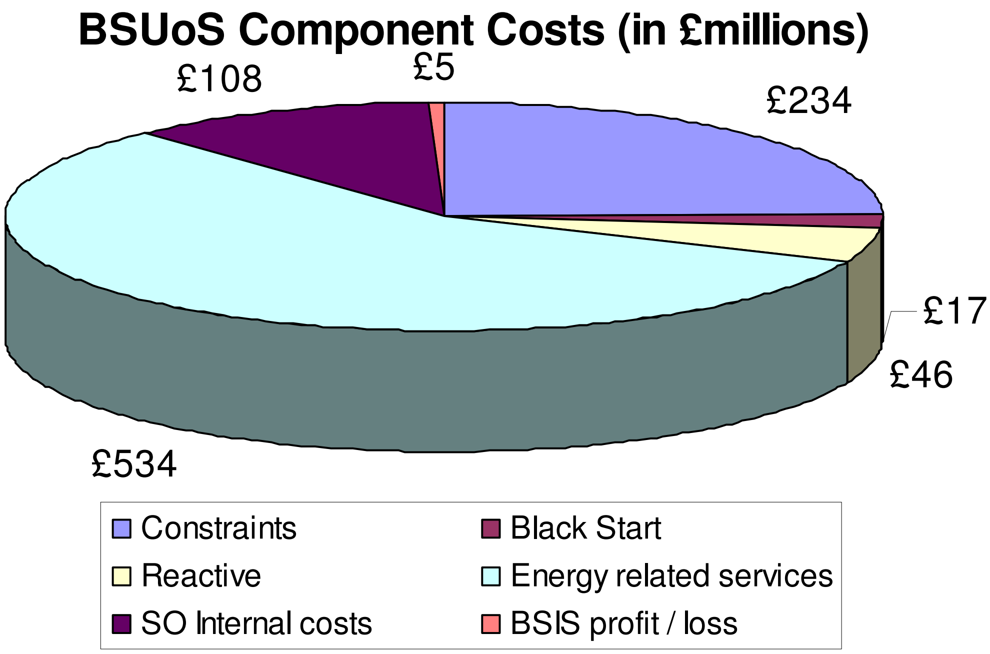


Figure 1 – 2009/10 BSUoS cost forecast (as at July 2009)

11. Figure 1 shows the relative costs of each of the components that make up the BSUoS cost forecast for 2009/10 (approximately £944m). Transmission losses are not recovered via BSUoS charges[4], instead the existing mechanism for allocating transmission losses to Parties is set out in Section T of the Balancing and Settlement Code[5]. Under the existing Code provisions, transmission losses are allocated to Parties on a uniform basis in proportion to each Party's metered energy.  The cost to the consumers of transmission losses is in the region of £300m p.a.

12. This consultation document is the first of our proposed 'mini' consultations and sets out our thoughts on the development and implementation of incentives for reactive power, transmission losses and black start.

13. This document is structured as follows:
    - Section 2 sets out the current incentive arrangements
    - Section 3 focuses on reactive power
    - Section 4 outlines some incentive options for transmission losses
    - Section 5 provides more detailed information on black start
    - Section 6 provides a summary
    - Section 7 lists the consultation questions
    - Appendix A – Reactive Power Procurement Arrangements
    - Contact Details – has the gas and electricity contact information

[4] Whilst Transmission Losses are not recovered via BSUoS, any profit or loss from the present Balancing Services incentive scheme is recovered via BSUoS.  The present incentive scheme for Transmission Losses is further described in Section 4.2 of this consultation document.

[5] http://www.elexon.co.uk/bscrelateddocs/BSC/default.aspx

14. 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 2009.

15. On conclusion of the Initial Proposals consultation, National Grid 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.

16. 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 |

17. Responses to this consultation will be published on National Grid’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 2 September 2009.

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

**by 5pm on 2 September 2009**

# Section 2
## Current Incentive Arrangements

*In this section we set out a high level overview of the current SO incentive scheme, the benefits and drawbacks of such a scheme and the aims of the incentive development.*

### 2.1 Overview

18. 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.

19. 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

20. 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.

21. 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.

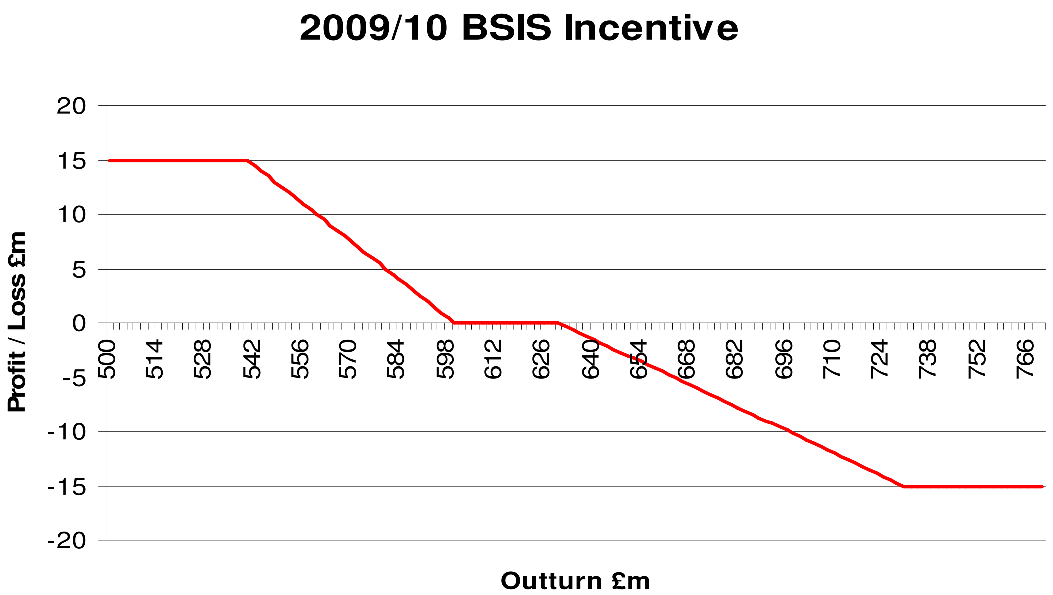


Figure 2 – BSIS Profit / Loss Profile

22. 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.

23. 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

24. 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.

25. Figure 3 shows the relative cost of each of the incentivised balancing components.

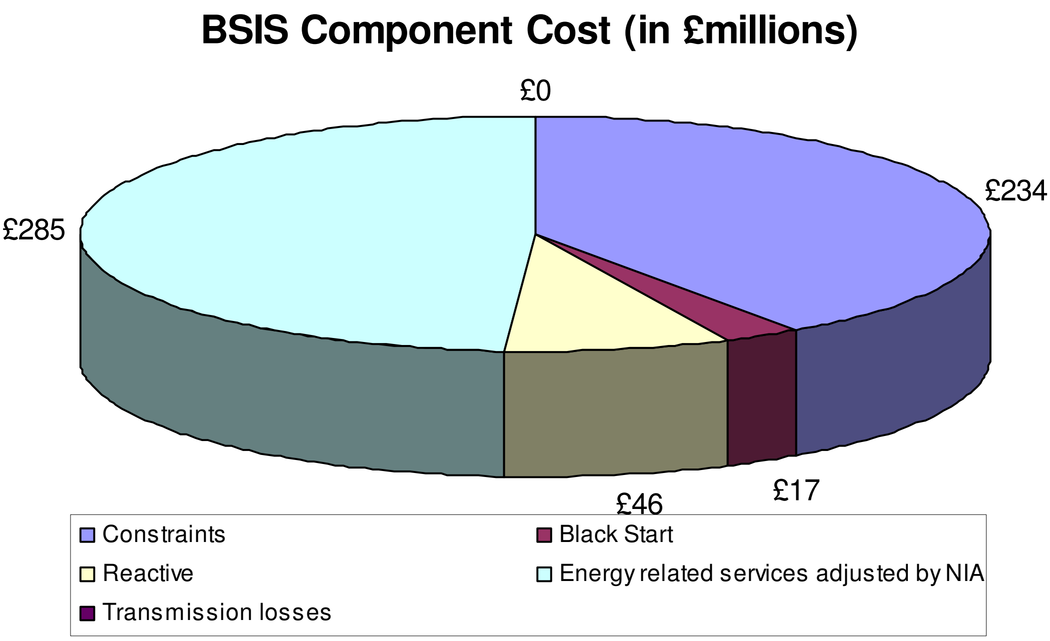


Figure 3 – 2009/10 BSIS cost forecast (as at July 2009)

26. 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 detailed in section 1, figure 1) the following elements need to be added:

- The Net Balance Adjustment (NIA) is an indexation used in BSIS to adjust the costs 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 Section 4.2 of this consultation document. 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.

## 2.2 Features of Bundled Scheme

27. The current BSIS incentive is a bundled scheme that incentives all cost components in a single pot. There are a number of benefits of a bundled scheme:
    - Interaction between components
      When taken balancing actions, there may be more than one service that the action can be attributed; e.g. when synchronising a generator to resolve a constraint issue, the generator may also be able to supply reserve and frequency response services. Allocating costs to each component is performed via a set of rules. In a bundled scheme these rules do not impact on the overall incentive performance.
    - Overall focus on driving down costs where most benefit can be achieved
      A bundled scheme generally focuses attention areas where National Grid can most drive value to the consumer.
    - Simpler to manage and administer
      A fully bundled scheme is generally easier to monitor and determine the overall direction of balancing costs.

28. Whilst there are a number of benefits of a bundled scheme as outlined above, there are a number of disadvantages of such a scheme. Some of these disadvantages are highlighted below:
    - Different risk profiles for each cost component
      The bundled scheme incentives National Grid to minimise overall balancing costs. However, due to the interaction between each cost component and their drivers, there will be different risk profiles for each component cost. This risk profile differential cannot be reflected in the overall scheme.

- Impact on the overall scheme for changes in one cost component
  A bundled scheme means that increases in costs in one component due to unforeseen changes (e.g. constraint costs) impacts on the overall scheme, reducing or removing the reward for cost reductions in other components.
- Inability to create specific focus on areas of greatest concern to the industry, regulator and government
- Potential barrier to longer-term schemes
  Certain components may not easily lend themselves to a longer-term scheme at present, such as constraints due to uncertainties around Transmission Access Reform.

### 2.3 Features of a one year scheme

29. Currently the BSIS target is agreed and implemented on a one year scheme. Therefore each year, a revised target is agreed.

30. There are a number benefits in the current one year scheme:
    - Accuracy of forecast
      The development of a robust yearly BSIS and BSUoS forecast is dependant on a number of external drivers such as power price. A yearly scheme is better able to adapt a revised forecast and hence updated target rather than a scheme of longer than one year duration.
    - Ability to reflect market changes
      For market changes that impact balancing costs (such as Transmission Access), a yearly (or a shorter) scheme is more able to reflect these changes than one of a longer duration.

31. Although there are a number of benefits associated with a one year scheme, there may be benefits in changing the duration of the incentive:
    - Accuracy of forecast
      A shorter scheme length would improve the accuracy of the forecast e.g. for a 6 month scheme, there would be more certainty of assumptions than for a year long scheme or for a scheme of longer duration
    - Consideration of investments in cost reduction with a longer than one year payback
      A scheme that has a duration of longer than one year would increase focus on investments that have a longer than one year payback
    - Regular oversight
      A scheme of shorter duration provides the opportunity for more regular oversight and review of performance with the ability to adjust the scheme accordingly
    - Targeting of costs to specific aims
      A change in duration of the incentive arrangements may facilitate the implementation of more specific aims and objectives, such as, a shorter term scheme focusing attention on minimising costs over a shorter period (e.g. constraint costs over the summer outage

period) where as a longer term scheme may better facilitate the aim of attracting new entrants.

**2.4 Summary**

32. The current BSIS incentive format has driven investment in cost reduction by National Grid that has provided considerable benefits to the industry in managing costs and risk.

33. There are a number of benefits that are provided by such a scheme as highlighted above. In addition, the current scheme is familiar to the industry and provides a simple year on year comparison of costs.

34. In line with the priorities set out in Ofgem's open letter, National Grid aim to explore longer-term incentive schemes. When considering the incentive development, National Grid and the industry must consider the benefits for such changes over and above the current arrangements.

35. To develop a longer-term incentive scheme it is necessary to consider the appropriateness of the unbundling of components and the further use of indexation. Unbundling and indexation will ultimately result in increased governance and complexity. In addition, an unbundled scheme may divert valuable resources from key areas into incentive areas where there is less impact to the consumer. Therefore, the development of indexation and unbundling will need to ensure that the risk / rewards are proportional to the benefit derived for the industry and the consumer.

36. Within this consultation, we consider the development of longer-term incentives for reactive power, transmission losses and black start.

# Section 3
## Reactive Power Incentive

*This section sets out the rationale for the development of an unbundled reactive power incentive with appropriate indexation for a longer than one year duration.*

### 3.1 Introduction

37. Reactive power production and consumption results from electricity transmission using alternating current. Reactive power is essential for maintaining voltage levels within designated limits across the transmission system. Reactive power is procured by National Grid as a balancing service and paid for by the industry via BSUoS charges. During 2008/09, reactive power costs were in the region of £62m, accounting for around 5% of total BSUoS costs.

#### 3.1.1 What is Reactive Power?

38. There are two types of energy which are managed by National Grid, Active and reactive power. Active power provides the actual energy that is eventually consumed, hence it is also referred to as 'Real Power'. Active power is managed through a number of mechanisms including the Balancing Mechanism.

39. Reactive power is produced or absorbed as a consequence of transmission of electricity using alternating current and its management plays an important role in the voltage profile across the system. Without the appropriate injections and absorptions of reactive power at correct locations, the voltage profile of the transmission system will exceed statutory, planning and operational limits.

40. Therefore, the management of reactive power is critical to maintaining a secure system. Failure to manage reactive power would result in excessive voltages, leading to potential voltage collapse and a system wide black out.

41. More information on reactive power can be found in the following links below:
http://www.nationalgrid.com/NR/rdonlyres/43892106-1CC7-4BEF-A434-7359F155092B/3543/Reactive_Introduction_oct01.pdf

#### 3.1.2 How is Reactive Power Procured?

42. Reactive power is managed on a locational basis through the generation and absorption of MVars[6]. There are a number of ways in which reactive power can be managed; the main methods being either through

[6] A Var is the unit of reactive power with a MVar being a million Vars.

the use of transmission equipment or through the instruction of generation.

43. *Transmission Connected Equipment* – National Grid can manage reactive power through operating transmission equipment such as reactors, capacitors and static variable compensators that absorb and/or generate reactive power. More information on how this is done can be found on the link above.

44. *Instruction of Generators* – Generators can vary the amount of reactive power they produce or absorb. The requirement for generators to provide reactive power is set out in the Grid Code. The output from the generator is determined by National Grid and is generally used to optimise the transmission network voltage profile. There are two types of arrangement by which reactive power can be procured from a generator; default arrangements and market arrangements. These are discussed in more detail in Appendix A.

45. It is the obligation of the Transmission Owner to ensure that there are sufficient reactive power sources connected to the transmission system to maintain system voltage for all securable system contingencies. National Grid will invest in additional reactive power equipment where there is a deficit. These deficits can be caused by a number of changes to the transmission system, such as a generator closures, increases in demand and increase in power transfers.

### 3.1.3 Current Incentive Arrangements

46. The cost of procuring reactive power is currently incentivised with the other balancing cost components as part of the Balancing Services Incentive Scheme (BSIS).

47. Changes in reactive power procurement costs feed into the overall BSIS incentive cost pot. Figure 4 shows the relative cost of reactive power when compared to other BSIS components.

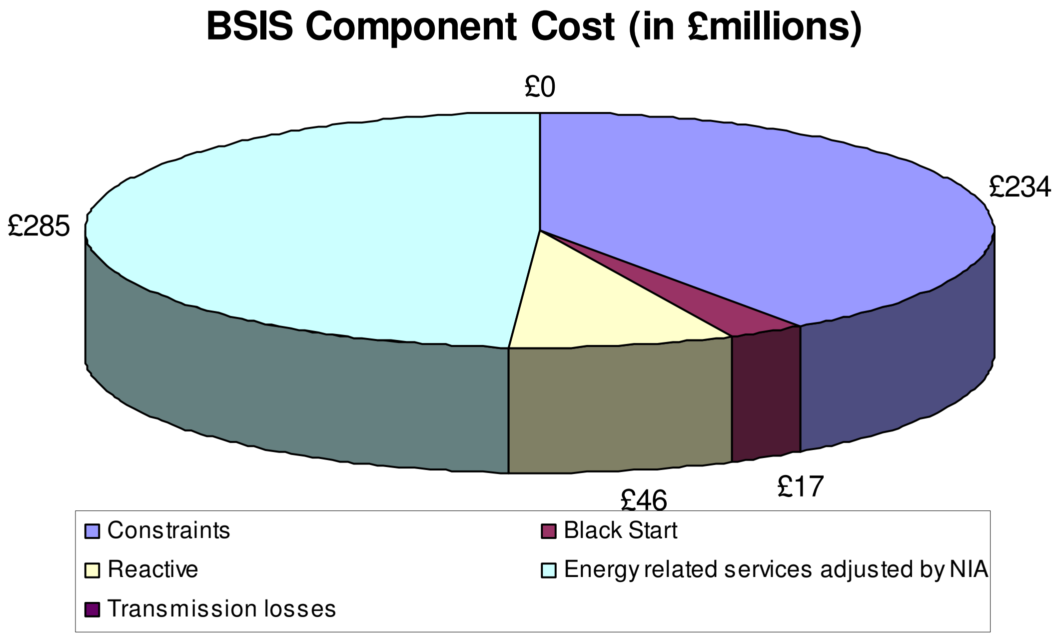


Figure 4 – 2009/10 BSIS cost forecast (as at July 2009)

### 3.1.4 Reactive Power Volumes and Costs

48. Figure 5 shows the reactive power volumes procured. The majority of the volumes procured are via default arrangements. The volumes procured via market arrangements has been declining since the introduction of the CUSC modification that indexed default reactive power prices to month ahead whole power prices. The increase in MVar volumes seen in April 2005 – March 2006 is mainly due to the introduction of BETTA.

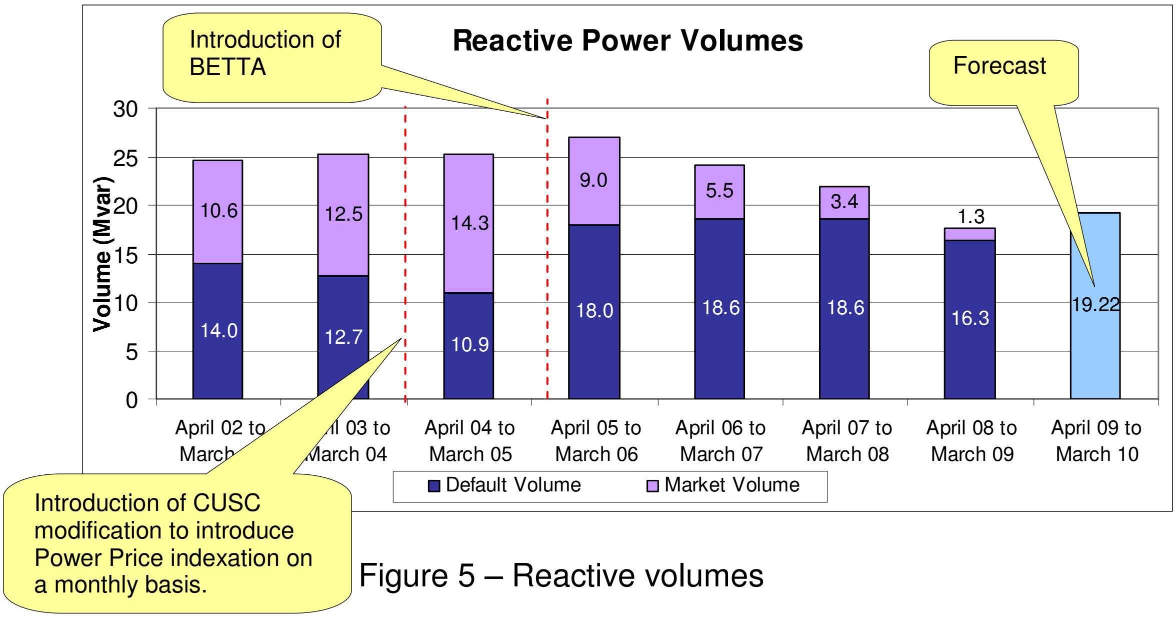


Figure 5 – Reactive volumes

49. Since April 2005, there has been a steady decrease in the volume of reactive power procured. However, as can be seen in Figure 6, the costs in April 08 – March 09 are significantly higher than in the previous

year. This is due to the increase in power price used to calculate the reactive power price (see section 3.2.1) from the power price used in the development of the reactive target.

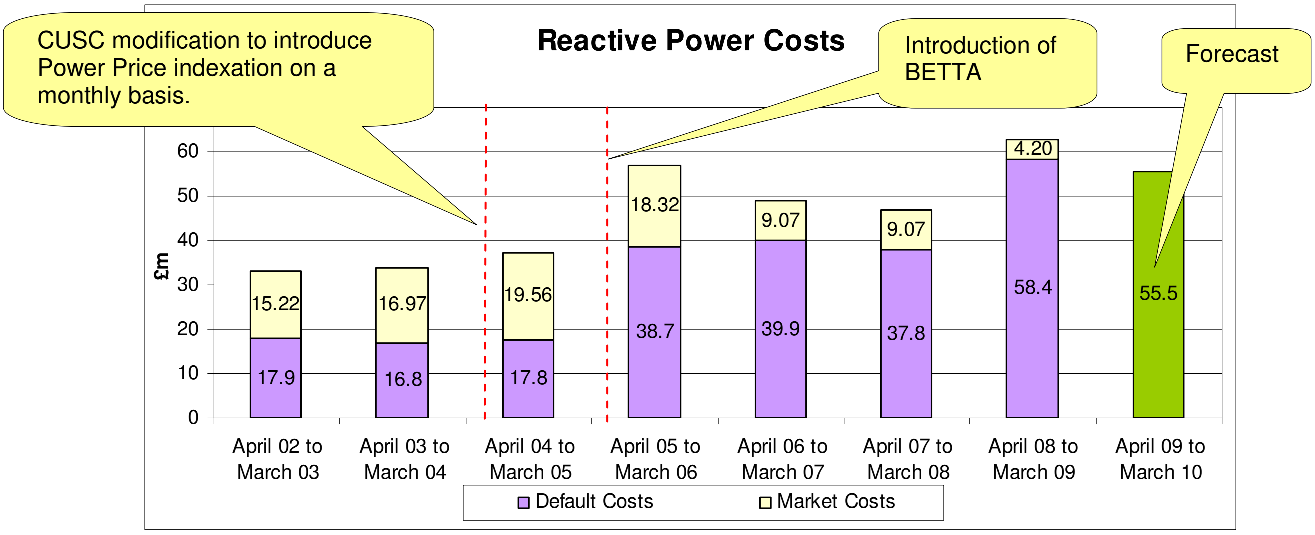


Figure 6 – Reactive costs

## 3.2 Reactive Power Cost Drivers

50. The main drivers for reactive power costs are:
- Power price
- RPI
- Level of active power flows across the transmission system
- Reactive Demand
- Commercial Reactive Power contracts
- Reactive power dispatch

### 3.2.1 Power Price

51. Payments for default reactive power services are indexed to RPI and wholesale power price. The default price is defined in CUSC Schedule 3 Appendix 1[7] and is calculated monthly based on the relevant month's RPI and month ahead wholesale power price. This process ensures that power price is accurately reflected in accordance to the most up to date data available. The formula for calculations can be found below:

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

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

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

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

52. Whilst reactive power default prices are calculated monthly, National Grid is incentivised on a reactive power cost target that is based on forward power price forecast that is up to 16 months ahead. The calculation is based on the same principle above but with National Grid forecasting the RPI and wholesale prices. The uncertainty of power prices introduces a risk into the reactive power forecast and can also lead to windfall gains and losses for changes in power price outside the forecast.

53. Figure 7 illustrates the accuracy of forecasting forward prices over time. The range has been developed comparing forward power prices and day ahead price. The P90 and P10 lines indicate the statistical boundaries for the accuracy of forecast power price when compared to the day ahead power price. There is a 10% chance that day ahead price will be below the P10 range and a 10% chance that the day ahead price will be above the P90 range. Therefore, there is an 80% chance that the day ahead price will be within the P10 – P90 range. As can be seen, the range of day ahead power prices when compared to the year ahead forecast increases the farther ahead the forward power price forecast has been developed. The graph indicates that:
   - at 4 weeks ahead the ability to forecast power prices accurately sits within a range of around +/-20% of actual prices
   - at 16 weeks ahead (approximate time between of the year ahead 'final forecast' and the start of the incentive scheme), the ability to predict forward power prices is only +50% / -30%

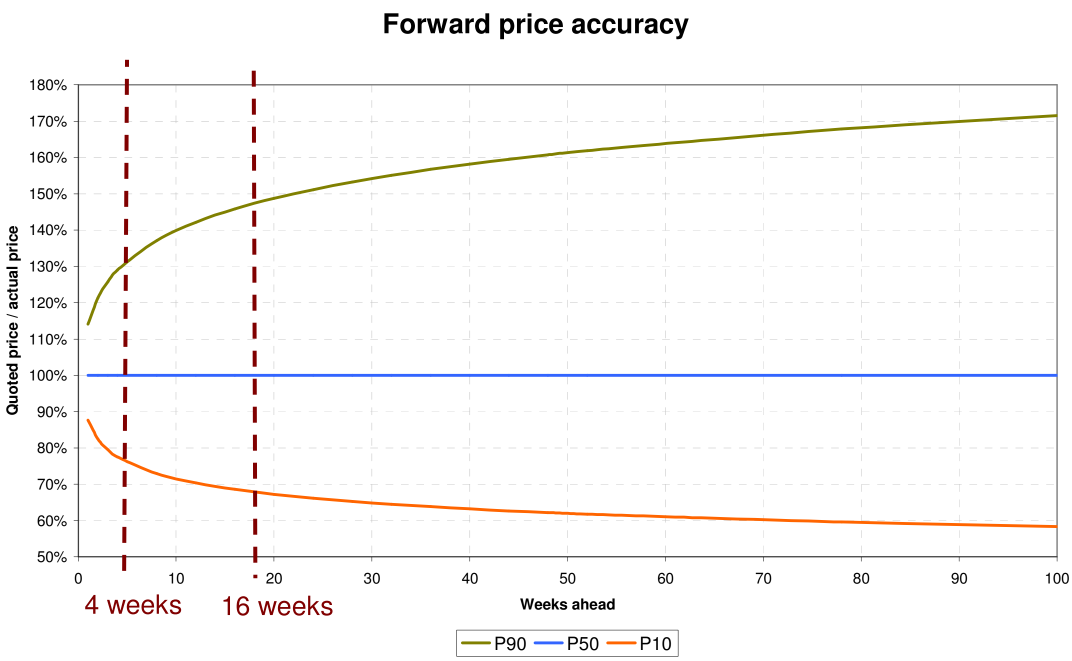


Figure 7 – Volatility of Power Price forecast

54. It can be seen that the risk of forecasting power price is directly related to the time between the forecast and real time. This demonstrates the difficulty for National Grid in accurately forecasting wholesale power prices at the year ahead stage.

55. Power price is a strong driver of reactive power costs as over 90% of reactive power is purchased using the default arrangements. National Grid has no influence over power price levels and, as shown above, it is difficult to accurately forecast.

### 3.2.2 RPI

56. Like Power Prices, RPI is forecast at the year ahead stage and is another factor not within the control of National Grid. RPI is based on the projections by the Bank of England. Figure 8 plots the forecast RPI (data by Experian) at different intervals.

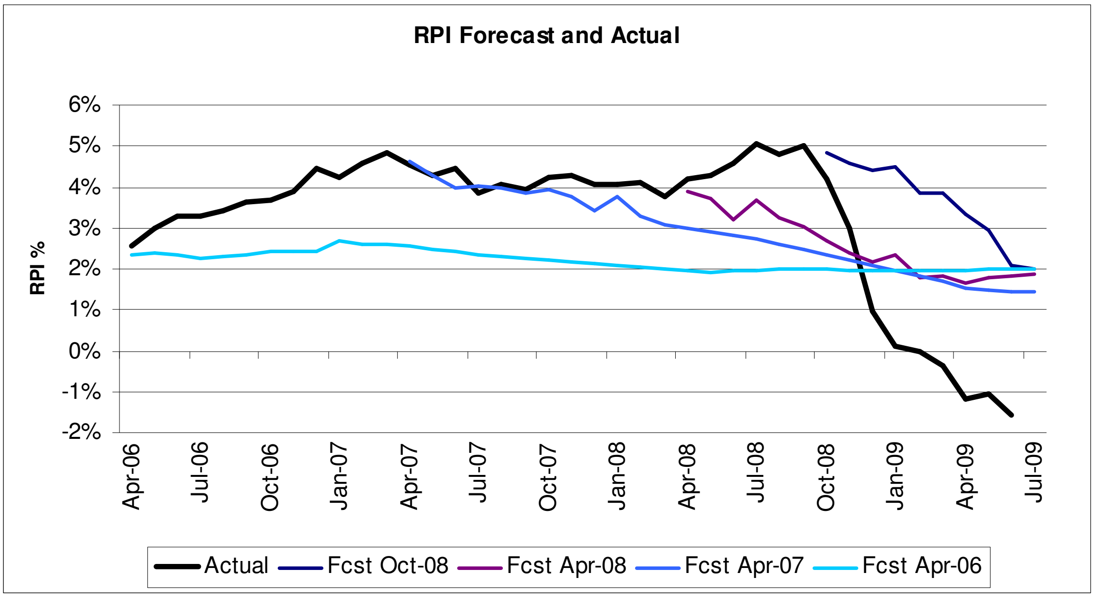


Figure 8 – RPI forecast and outturn (data by Experian)

57. The actual versus outturn of RPI can be seen differ significantly from the forecast with differences in excess of 2%. Therefore, there is a risk that changes in RPI, that National Grid cannot control, will influence reactive costs.

### 3.2.3 Level of active power flows across the transmission system

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

59. Figure 9 shows the reactive power produced or adsorbed by an overhead line. As can be seen, the volume of reactive power absorbed (increasing the reactive requirements) increases as active power flows across the line increase. Therefore, as active power flows across the system increase, the level of reactive power absorbed also increases.

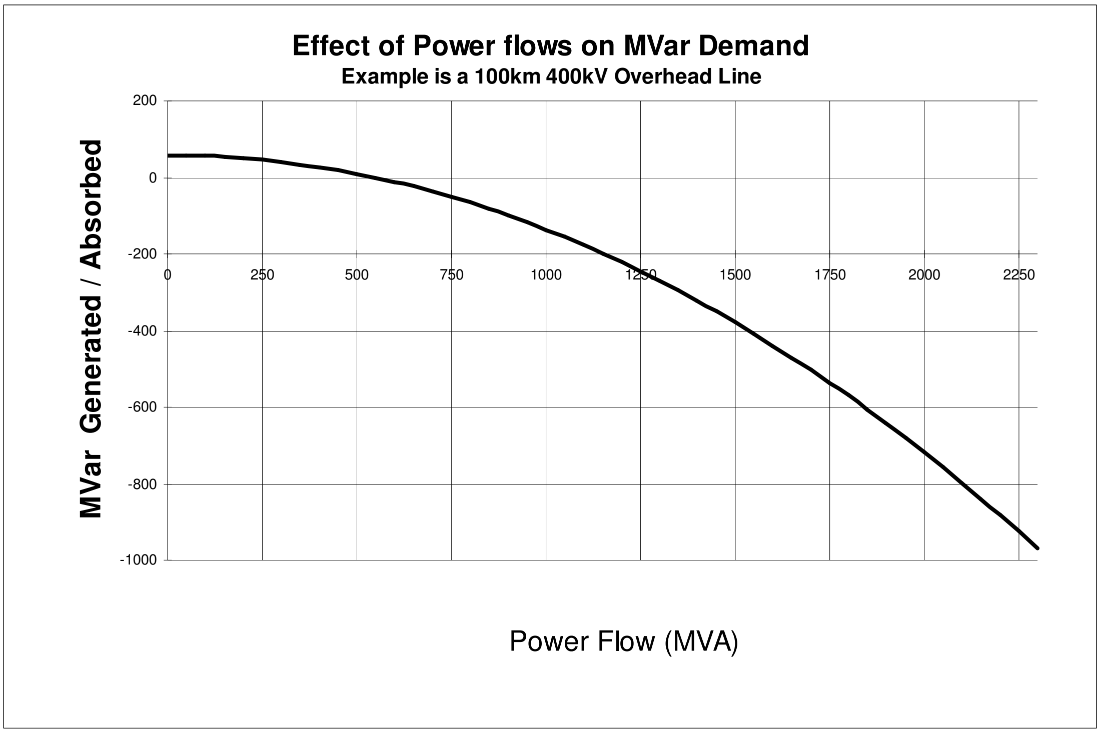


Figure 9 – Impact of Power Flows on Reactive Power

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

### 3.2.4 Consumer Reactive Power Demand

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

62. Therefore, as with energy demand, reactive power demand is dependant on short and long term weather patterns. Although reactive power demand is dependant on the same factors that impact energy demand, these can be forecast with reasonable accuracy.

63. The volatility of consumer reactive power demand is limited by National Grid's ability to accurately forecast the reactive demand. The ability of National Grid to accurately forecast reactive demand results in limited windfall gains or losses due to unforeseen changes.

### 3.2.5 Commercial Reactive Power contracts

64. Commercial contracts for the procurement of reactive power are assessed against the relevant economics when compared with the default mechanism. The contract is dependant on the provider submitting a bid and the bid being accepted by National Grid. Therefore, National Grid is in control over the acceptance of contracts and can influence this reactive cost driver.

65. As shown in figure 3, the volume of reactive power procured via market arrangements has decreased over the last four years. National Grid aims to review the market arrangements currently in place and has recently submitted a CUSC Amendment Proposal (CAP173) to improve the timescales for reactive market tender acceptance.

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

### 3.2.6 Reactive power dispatch

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

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

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

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

## 3.3 Potential Incentive Options

71. Reactive power costs are currently incentivised within the bundled Balancing Services Incentive Scheme (BSIS) as set out in section 2.

72. This part of the document looks at potential changes to the way in which reactive power could be incentivised. The potential changes considered are:
    - Unbundling of reactive power from the present single incentive scheme that covers all cost components (e.g. Reserve, Reactive,

Constraints and Response) and the development of a separate reactive power incentive.
- Indexation of the reactive power costs
- Increasing the period over which reactive power is incentivised from the present one year incentive

**3.3.1 Indexation of Reactive Power**

73. Section 3.2 covered the main drivers for reactive power costs. There are a number of drivers that National Grid can control or forecast. However, there are a number of areas where National Grid is unable to control or accurately forecast.

74. To manage these external drivers that are outside the direct control of National Grid or cannot be accurately forecast, it may be appropriate to develop an indexation methodology that updates the reactive power cost target in line with fundamental changes to the assumptions agreed at the time of the original forecast.

75. There are a number of possible benefits from the development of a reactive power indexation methodology:
    - limits the potential for windfall gains and losses associated with changes to external factors outside the control of National Grid
    - appropriately targeted incentive based solely on reactive power cost drivers within the control of National Grid
    - enable the develop of a longer term incentive for reactive power, leading to longer term cost savings

76. Indexation could be implemented within the current scheme format, with the overall BSIS target being adjusted for changes in indexed components, or it could be implemented as part of a separate reactive power incentive.

77. The indexation methodology should not have an impact on any other BSIS cost drivers and, if possible, not be overly complex to implement. The implementation of an indexation methodology will add complexity over and above the current arrangements and also provide a moving BSIS incentive target.

Question 1 – What benefits do you see for the development of an indexation methodology for reactive power costs? What drivers should be included in such an index?

**3.3.2 Longer Term Incentives**

78. There may be a number of benefits to extending the current one year reactive power incentive to a longer term incentive.

79. *Annual Scheme* – Under the current annual incentive regime National Grid ensures reactive power costs are managed effectively through:

- minimising volumes procured through the default mechanism via optimised dispatch and the utilisation of transmission equipment
- accepting reactive power tenders for market arrangements that offer better value or reduce risk than using default arrangements

80. *Longer term schemes* – Annual schemes only allow realisation of short term cost benefits and, therefore, logically focus the majority of resources on short term savings. Any work that is done to generate long term cost savings is not captured in the current scheme. Some of the possible longer term cost reductions that have been identified include:-
    - Reviewing the Market Arrangements for reactive power Services. Looking at new ways of increasing the provision of services via this route, which may lead to more economic procurement. Whilst this review is already underway, longer-term incentives will provide a greater focus to such market arrangements.
    - Procurement of longer-term services via Enhanced Reactive Power Service Arrangements from third parties (e.g. third party synchronous compensation devices). Specifically, a longer-term incentive scheme would better incentivise such arrangements if providers have high up front costs with longer-term paybacks.
    - Invest in services with longer payback such as enhancing IT systems to optimise the management of reactive power.

81. As shown in section 3.2, there are a number of cost drivers outside the direct control of National Grid. Therefore, the ability to accurately forecast reactive costs for a longer than one year period needs careful consideration. The implementation of effective indexation would in part address this issue but would be dependant on the indexation methodology applied.

82. The development and implementation of a longer than one year reactive power target could be implemented within the current bundled scheme format.

| |
|---|
| Question 2 – What benefits do you believe there are in the implementation of a longer than one year scheme? |

### 3.3.3 Unbundling of Reactive Power from BSIS

83. Apart from sharing some of the cost drivers (namely wholesale power price), reactive power has no direct relationship or dependency with any other component of BSIS. Therefore, it would be relatively easy to unbundle reactive power from the other BSIS components and develop a separate incentive scheme.

84. When compared with the current incentive arrangements, there are a number of possible benefits from the unbundling of reactive power and the development of separate reactive power incentive:
    - targeted incentive with suitable reward and risk profile based solely on reactive power cost drivers

- enable greater industry understanding of reactive power through more detailed analysis
- enable the development of a longer term incentive for reactive power

85. However, there are be a number of considerations that need to be addressed:
    - the incentive would need to be appropriate for the possible impact a separate incentive would have on BSUoS and the benefit to the industry and the consumer

86. The impact of a separate reactive power incentive on BSUoS would be:

**Current BSUoS**

BSUoS = BSIS + NIA + TLIC + BSIS Incentive Payment + Other minor terms

**BSUoS With an Unbundled Reactive Incentive**

BSUoS = $BSIS_{without\ reactive}$ + Reactive Outturn Cost + NIA + TLIC + $BSIS_{without\ reactive}$Incentive Payment + Reactive Incentive Payment + Other minor terms

87. Therefore, the only impact on BSUoS would be the impact of the Reactive Incentive Payment, and therefore would depend on the caps and collars and sharing factors of the unbundled incentive. For example, a maximum profit / loss of £1m would increase / decrease BSUoS by approximately 0.1%.

Question 3 – Are there any additional benefits or drawbacks in the development and implementation of an unbundled reactive power incentive?

### 3.4 Summary

88. The current incentive arrangements focus National Grid on driving down reactive power costs across the year.

89. However, there are a number of reactive power cost drivers that are outside the control of National Grid and also, cannot be accurately forecast. The volatility of such unforecastable drivers can cause an unmanageable risk when considering the development of a reactive power incentive target.

90. To develop a more targeted incentive for reactive power, a method of indexing these external drivers that are outside the control of National

Grid could be developed. Such indexation could be implemented within the current BSIS arrangements although the implementation of such an index would add complexity to the overall scheme.

91. Suitable indexation would incentivise National Grid on elements of reactive power that were within its control, and provide appropriate reward for performance above or below the agreed target.

92. National Grid believes that the development of suitable indexation methodology would allow the development and implementation of a longer term reactive power incentive. There are a number of benefits in the development of longer term schemes:
    - Focus National Grid on the development of longer term cost reduction strategies such as:
        - Reviewing the Market Arrangements for reactive power Services that may lead to more economic procurement.
        - Procurement of longer-term services via Enhanced Reactive Power Service Arrangements from third parties (e.g. synchronous compensation).
        - Invest in services with longer payback such as enhancing IT systems to optimise the management of reactive power on the Grid.
        - Development of longer term risk reduction strategies

93. The implementation of a longer term incentive could therefore drive additional value for the industry enabling National Grid to be incentivised on driving costs more innovatively providing cost savings to the industry over a longer period.

94. However, a longer term incentive may lead to windfall gains and losses for changes in reactive power costs outside of the forecast level. This would depend on the effectiveness of any indexation if implemented.

95. The success of a longer term reactive power incentive rests on National Grid being incentivised only on elements that are within its control and the ability of National Grid to drive additional value to the consumer for reducing these costs.

> Question 4 – Please provide your views on the development of the reactive power incentive? Do you see any benefits in changing the current arrangements?

# Section 4
## Transmission Losses Incentive Development

*This section sets out the rationale for the development of an appropriate transmission losses incentive on National Grid. We show that National Grid has limited control over the volume of transmission losses and outline two alternative methods of transmission losses incentives and seek views form the industry on the feasibility of such incentive development.*

### 4.1 Introduction

96. The GB electricity transmission system is the high voltage electricity network connecting large scale generation to demand. A small percentage of the energy transferred over the GB electricity transmission system is lost due to physical processes of transmitting electricity. This 'lost' power is known as transmission losses and is currently around 1.7% of the power transmitted.

### 4.1.2 What is the significance of Transmission losses?

97. The financial impact of this volume of transmission losses can be estimated by using the transmission loss volumes and power price. Using the baseload forward price used in the determination of the 2009/10 BSIS forecast (approximately £47.00/MWh), and the transmission losses volume forecast of 6TWh, the cost to the consumers of transmission losses is in the region of £300m p.a. This is equivalent, on average, to a need to generate 685MWh every hour of the year simply to meet transmission losses.

98. Figure 10 below shows transmission losses volumes since NETA go-live.

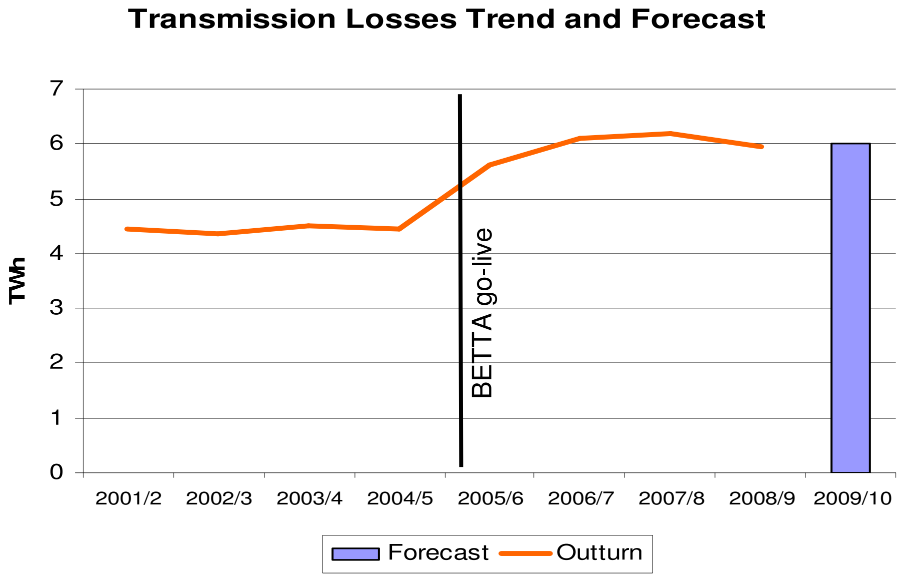


Figure 10 – Transmission Losses volumes

99. As can be seen, transmission losses have increased since the introduction of BETTA but since 2006/7 seem to be levelling off at about 6.0TWh. However, with the forecast increase in new generation connecting over the coming years, especially wind generation in the north of the system, it is envisaged that transmission losses volumes will increase as a result of the increase in power flows across the system. The Seven Year Statement indicates that at peak demand, losses will increase by 29% between 2010 and 2016[8].

100. Currently National Grid is incentivised to reduce transmission losses with the industry supplying the transmission losses (as outlined in the BSC). There are currently no direct incentives on generation or demand to reduce or manage transmission losses volumes.

## 4.2 Transmission Losses within the present Incentive Structure

101. As stated within the introduction to this consultation document, Transmission losses are not a cost that National Grid is directly exposed to in relation to balancing the system. However, National Grid is incentivised to minimise losses as part of BSIS

102. Within BSIS, the incentivised balancing costs are split into the following main component parts:

$$IBC = CSOBM + BSCC + TLIC + NIA$$

Where

| | |
|---|---|
| *IBC* | – this is the incentivised Balancing Costs |
| *CSOBM* | – this is the total costs of all Balancing Mechanism actions |
| *BSCC* | – this is commercial and ancillary service contract costs, including trading |
| *TLIC* | – adjustment based on performance against transmission losses target |
| *NIA* | – adjustment to reflect the costs that are dependent on market length and wholesale power prices |

103. The TLIC term in the formula above, adjusts the BSIS incentive target if:
- transmission losses are below the agreed target, the adjustment is negative, moving the BSIS costs downward, potentially increasing the profit or decreasing the loss
- transmission losses are above the target agreed, the BSIS costs are positive, moving the BSIS costs upward, potentially decreasing the profit or increasing the loss

104. To convert the transmission loss volume into a cost, the current incentive uses a reference price. The transmission losses reference price is

[8] http://www.nationalgrid.com/uk/sys%5F09/default.asp?action=mnch7_14.htm&Node=SYS&Snode=7_14&Exp=Y#Power_Losses

based on the forward price plus an adjustment to replicate the shadow price of carbon[9] (as implemented in 2008/09). The forward price used was £47.09/MWh (the average forward price for 2009/10).

105. Figure 11 shows the level to BSIS adjustment, for 2009/10, for a range of potential transmission losses outturns.

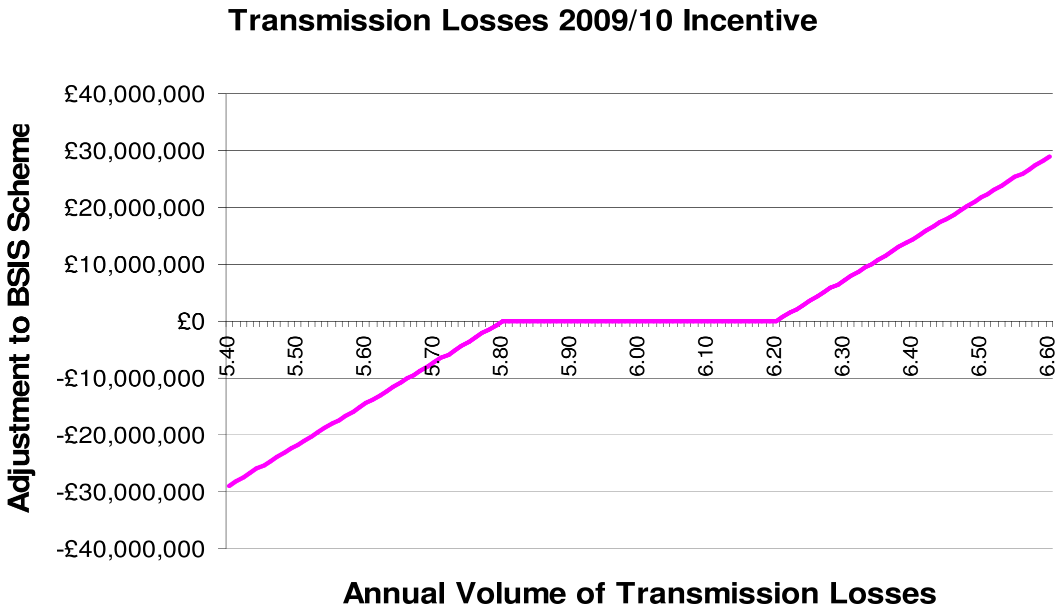


Figure 11 – Calculation of Transmission Losses adjustment

106. Figure 11 shows the transmission losses target on the x-axis for 2009/10 which has a 6.0TWh target with a 0.2TWh deadband.

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

108. The impact of a 10% change in transmission losses on the BSIS scheme is shown in figure 12.

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

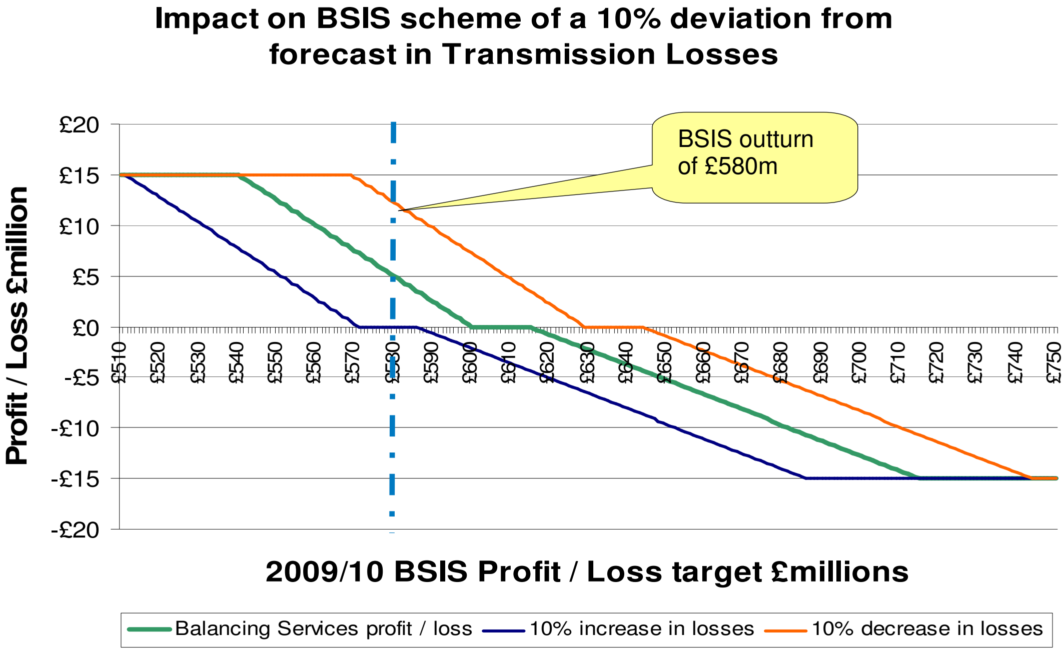


Figure 12 – Impact of Transmission Losses adjustment on BSIS

109. As can be seen in figure 12, for balancing cost outturn of £580m, with no losses adjustment, the BSIS scheme would deliver a £5m profit. With a 10% increase in transmission losses, this would adjust scheme to deliver a £0m profit with a 10% decrease in transmission losses resulting in a £12.25m profit.

### 4.3 Which factors influence Transmission losses?

110. Losses can be split into two main components:

- **Fixed losses** are losses which do not vary significantly with power flow. Fixed losses arise in:
  - Transformers - from magnetising the iron core; and
  - Overhead lines - include losses dependent on voltage levels, length of line and climatic conditions.
- **Variable losses** are due to the heat caused by the flow of current through transformers and lines. Variable losses increase with:
  - Current flow (and associated power flow); and
  - Distance of flows.

#### 4.3.1 System Operator Control of Transmission losses volumes

111. Variations in transmission losses are predominantly driven by variations in the disposition and level of generation and demand, although longer term trends in transmission loss are also influenced by Transmission Owner (TO) investment and replacement of transmission system equipment.

112. The volume of fixed losses is predominately determined by the number of transformers on the system. As the number of transformers increases, the level of fixed losses also increases.

113. Variable losses make up approximately 60%[10] of losses. Therefore, a significant volume of transmission losses is determined by the level of flows across the transmission system.

114. The Transmission Owner (TO) can influence the level of losses by investing in transmission equipment that minimises their impact on transmission losses. There is a requirement on the TO to consider the procurement of low loss equipment when replacing or installing assets.

115. National Grid manages flows on the system using a number of tools. The main tool used is the Balancing Mechanism where National Grid can increase (Offer) or decrease (Bid) generation to balance the system. When considering which Bids and Offers to take, National Grid uses a number of factors to determine the most economic and efficient action. These factors are set out in the Balancing Principles Statement[11].

116. The location of these Bids and Offers accepted by National Grid will influence the level of transmission losses incurred on the system. The level of influence each Bid or Offer has on losses when compared to other generation Bids or Offers is one of the factors used in determining which action to take. The impact on transmission losses is only one of the factors used in determining which bids and offers to take. Other such factors are generator dynamics and submitted prices. Where corresponding services (e.g. bids or offers) can not be differentiated on cost or dynamics, the action that delivers the greatest reduction in transmission losses will be taken.

117. In addition to the management of generation output, National Grid can influence losses by changing transmission running arrangements and voltage profiles. These measures generally alter the flow of power across a circuit(s). Although National Grid can influence losses through the control of transmission equipment, this has significantly less impact on flows, and hence losses levels, than changes in generation patterns.

118. The volume of energy managed by National Grid via the Balancing Mechanism is approximately 3% of the total energy traded by the market. With the majority of energy being managed by the market and subsequent self dispatch of generation, National Grid has marginal control over the volume of losses caused by flows over the transmission system.

[10] To calculate this figure, the fixed losses value from the Seven Year Statement was used and the 2009/10 Transmission Losses target of 6.0TWh.
[11] http://www.nationalgrid.com/NR/rdonlyres/8157C90A-A441-42E7-980D-5E132E04FF28/32906/BPSeffectivefrom1apr09.pdf

119. Using these numbers above, we can estimate the level of control National Grid has over transmission losses:

| *Annual forecast level of losses for 2009/10* | | *Level of variable losses* | | *Volume of energy managed in the BM* | | *Losses managed in the BM* |
|---|---|---|---|---|---|---|
| *6.0TWh* | x | *60%* | x | *3%* | = | *0.108TWh* |

120. In addition, the impact of generation location on transmission losses is approximately 0% - 7% dependent on generation location. Therefore, National Grid can only influence 0.108TWh x 3.5%[12] = 0.0038TWh or 0.063% of the transmission losses volume via direct manipulation of generation output levels.

### 4.3.2 Generation pattern impact on Transmission losses

121. A key driver in variable transmission losses is the disposition of generation. The ability of National Grid to predict generation patterns determines the accuracy of the transmission losses incentive target.

122. There are a number of main factors that can change the predicted generation pattern:
- Changes in fuel price
- Generation outages
- Changes in demand levels
- Interaction with European markets

123. A recent report investigating transmission losses on the electricity transmission system considered the impact of a recent generation outage on transmission losses[13]. Section 7 of the report considered the consequence on transmission losses as a result of an unplanned outage at Hinkley Point B Power Station between 22 September 2006 and 31 May 2007 where generation fell from around 1200 MW to 0 MW.

124. Hinkley Point B Power Station, with a capacity of approximately 1200MW is one of the few large Power Stations in the South West of England and, in general, its reduction in output would have resulted in increased output from other sources across Great Britain and these, on average, would lead to higher system losses during the period studied. The approximate level of transmission losses that would have occurred had Hinkley Point B Power Station operated at full output over this period is presented in Figure 13.

[12] Used the average between 0% and 7%
[13] http://www.nationalgrid.com/NR/rdonlyres/4D65944B-DE42-4FF4-88DF-BC6A81EFA09B/26920/ElectricityTransmissionLossesReport1.pdf

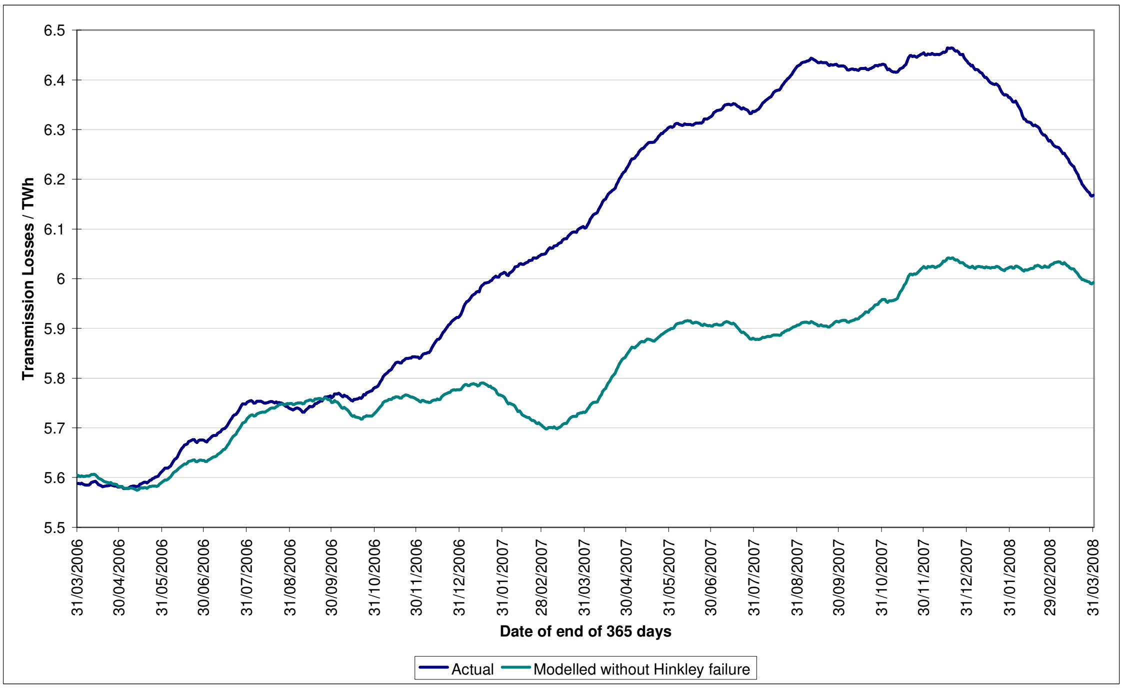


Figure 13 – Rolling average annual Transmission losses

125. This figure illustrates the effect that changes in the disposition of generation or demand can have on the level of transmission losses. The changes occur continuously due to generation plant maintenance, breakdown and changes in the economics of plant operation through such factors as changes in primary fuel price.

126. The increase in losses as a result of the unplanned Hinckley Point B Power Station outage resulted in an £7m transmission losses adjustment (the TLIC term as described in section 4.2) to the 2007/08 BSIS scheme.

127. The deadband in place for the current 2009/10 transmission losses incentive has been implemented to reflect the uncertainty with generation patterns.

### 4.3.3 Reference price

128. The transmission losses reference price is based on the forward price plus an adjustment to replicate the shadow price of carbon[14] (as implemented in 2008/09). The forward price used was £47.09/MWh (the average forward price for 2009/10). The shadow price of carbon adjustment was calculated using the differential between the market price of carbon and the shadow price of carbon taking into account the relative generation types and efficiencies. An indicative shadow price of carbon of £7.92/MWh was calculated for 2009/10 resulting in a transmission losses reference price of £55.00/MWh.

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

129. This reference price is utilised for the entire year and so does not take into account changes in the power price over the year or the market price of carbon.

130. To more accurately reflect the cost of losses, it may be beneficial to improve the granularity of the calculation of the reference price, e.g. a monthly reference price based on forward power prices and forward market price of carbon.

### 4.4 Possible incentivisation options for Transmission losses

131. In this section, we explore the development of an appropriate transmission losses incentive on National Grid. In addition, we look at alternative incentives outside of the SO that may further driver down the transmission losses volumes.

132. The level of transmission losses are set to increase over the next 7 years (as detailed in section 4.1.2). Within this context and noting the present level of transmission losses, appropriate incentives need to be considered to minimise the level of losses.

#### 4.4.1 Development of an Indexation Methodology

133. As detailed in section 4.3.2, a key driver of variable transmission losses is dependant the location and output level of generation, and the relevant level and location of demand.

134. In developing a suitable targeted incentive, it may be appropriate to develop some form of indexation methodology that alters the transmission losses target dependant on this key driver. Such indexation would remove the potential for windfall losses or gains simply as a result of changing generation patterns influenced by outages, demand levels and fuel prices. The deadband in place for the current 2009/10 transmission losses incentive has been implemented to reflect the uncertainty with generation patterns, with appropriate indexation the need for such a deadband could also be reviewed.

> Question 5 – What benefits do you see for the development of an indexation methodology for transmission losses? What drivers should be included in such an index?
> Question 6 - Please provide your views on whether the SO can influence sufficient drivers to reduce Transmission Losses?

#### 4.4.2 Multi-year Scheme

135. A multi-year target could be developed that had suitable sharing factors and deadbands that reflected the risks in changes to outturn volumes from those forecast. However, the implementation of a multi-year incentive may lead to an increase in wind fall gains and losses for changes in transmission losses outside the control of National Grid.

136. To overcome this issue it may be necessary to consider, the implementation of an appropriate index , as described in section 4.4.1 when considering the developing a multi-year target.

137. There may be a number of benefits to extending the current one year Transmission losses incentive to a longer term incentive, with appropriate indexation.

138. *Annual Scheme* – Under the current annual incentive regime National Grid ensures Transmission losses are managed effectively through the optimised dispatch of generation via bids and offers, and the configuration of transmission equipment

139. *Longer term schemes* – Annual schemes only allow realisation of short term cost benefits and, therefore, logically focus the majority of resources on short term savings. Any work that is done to generate long term cost savings is not captured in the current scheme. Some of the possible longer term cost reductions that have been identified include investing in services with longer payback such as enhancing IT systems to optimise the management of transmission losses.

> Question 7 – What benefits do you believe there are in the implementation of a longer than one year scheme?

### 4.4.3 Unbundling of Transmission Losses

140. To better reflect the risk profile of transmission losses, one option could be to unbundle transmission losses from the current BSIS scheme. If unbundled, a separate incentive that more accurately reflects the risk profile could be developed.

141. When compared with the current incentive arrangements, there are a number of possible benefits from the unbundling of transmission losses and the development of separate transmission losses incentive:
    - targeted incentive with suitable reward and risk profile based solely on transmission losses cost drivers
    - enable greater industry understanding of transmission losses through more detailed analysis
    - enable the development of a longer term incentive for transmission losses

142. However, there are be a number of considerations that need to be addressed:
    - the incentive would need to be appropriate for the possible impact a separate incentive would have on the volume and costs of transmission losses and the benefit to the industry and the consumer

143. The management of Transmission Losses is not intrinsically linked to other BSIS components and, therefore, we believe that the unbundling of transmission losses from the BSIS scheme would be relatively straightforward.

| |
|---|
| Question 8 – Are there any additional benefits or drawbacks in the development and implementation of an unbundled transmission losses incentive?<br><br>Question 9 – Please provide your views on the development of the transmission losses incentive? Do you see any benefits in changing the current arrangements? |

### 4.4.4 Industry Incentive

144. As detailed in section 4.3.2, a key driver of variable transmission losses is the disposition of generation. .

145. Consideration is presently being made within the BSC to introduce seasonal zonal transmission losses scheme via BSC modification P229[15]. The proposed seasonal zonal scheme will enable the variable costs of transmission losses to be allocated on a cost-reflective basis and reflected directly on parties that impact them.

146. Such a proposal, if implemented, could reduce transmission losses in both the short term, through changes in generation dispatch, and in the long term through locational signals for new investment in power generation and demand.

### 4.4.5 TO incentive

147. As described in section 4.3, the Transmission Owners (TO) can influence the level of fixed losses by investing in transmission equipment that minimises their impact on transmission losses. There is a requirement on the TOs to consider the procurement of low loss equipment when replacing or installing assets. Further consideration could be made to developing a targeted TO incentive to reinforce this requirement.

| |
|---|
| Question 9 – Are there any benefits in the development of a TO incentive to manage fixed losses? |

## 4.5 Alternative methods of incentivisation of Transmission losses

148. There may be benefit in considering a different transmission losses incentive that would allow National Grid to have greater control over the cost or volume of transmission losses or provide some benefit to the industry in minimising transmission losses.

15 http://www.elexon.co.uk/changeimplementation/ModificationProcess/ModificationDocumentation/modProposalView.aspx?propID=254

149. Below we provide a brief outline of two incentives options on National Grid.

### 4.5.1 Transmission Losses Forecast Incentive

150. There are a number of alternative transmission losses forecast incentives that could be developed. The format would depend on the benefit seen by the industry of National Grid providing such information.

151. With the possible introduction a BSC modification (P229) where the industry will supply transmission losses volumes dependant on their location, there may be some benefit in developing improved transmission loss forecast information to the industry.

152. The cost of providing losses will vary depending on generation disposition and demand. A forecast of the zonal losses for each generating and demand zone may improve dispatch decisions across the industry.

153. National Grid could provide the industry with a zonal transmission losses forecast. This forecast could help in the assessment of the economic self dispatch of generation across the system.

154. The main factor with the usefulness of the transmission losses forecast would be with the granularity of the scheme and how far in advance the forecast would be provided. For instance, a transmission losses forecast could be provided at the day ahead stage using the submitted indicative data from the market for the 48 periods of the next day.

155. The level of reward would depend on the benefit to the industry and the cost to National Grid of providing the service.

| |
|---|
| Question 10 – What benefit do you see in developing a transmission losses zonal forecast incentive? |

### 4.5.2 Transmission Losses Procurement Incentive

156. Transmission Losses are currently managed under the BSC. The volumes are determined post event and the consumption and production accounts are adjusted to match the actual volumes.

157. An alternative to the market providing losses, could be that National Grid procures the losses on behalf of the market in a similar manner to the Gas shrinkage incentive[16]. National Grid would be responsible for the economic procurement of transmission losses volumes on behalf of the market, with the cost of losses being allocated to the market via

[16] Section 4 of the 2009/10 National Grid Gas (NTS) SO Initial Proposals consultation outlines the shrinkage incentive. http://www.nationalgrid.com/NR/rdonlyres/D8E0111F-5E59-4390-A6EF-A26BA444CC28/29689/SOIncentivesInitialProposals_v10.pdf

Transportation charges (i.e. a removal of transmission losses from the BSC). The benefits of such a change may come from a single party forecasting and procuring losses.

158. The incentive would mean that industry would no longer supply losses volumes. The volumes would be procured by National Grid. The incentive would be for National Grid to procure the losses volumes below a target reference price; limiting the cost of losses to the industry.

159. As National Grid would be procuring losses on behalf of the industry, and therefore have control over the location of the energy procured, which in turn may help to reduce losses.

160. The cost of transmission losses would be recovered from transmission system users in line with our licence obligations to develop charging methodologies. .

161. The introduction of such an incentive would have an impact on a number of Codes and a review of both the BSC and National Grid's Transmission Charging Methodology would be required.

| |
|---|
| Question 11 – What benefit do you see in the development of a Transmission Losses procurement incentive similar to the Gas Shrinkage incentive? |

### 4.6 Conclusion

162. It maybe appropriate to change the current incentive arrangements to better reflect the level of control National Grid has on transmission losses and an incentivise behaviours that reduce overall volumes and costs.

163. Possible incentive development options considered for National Grid are:
    - A separate unbundled longer-term incentive with suitable indexation , caps, collars and sharing factors;
    - Forecast incentive dependant on the benefit seen by the industry;
    - Procurement incentive aimed at managing transmission losses

164. The development of appropriate indexation would reduce the potential for windfall gains and losses and may allow for the implementation of longer term targets.

165. The development and implementation of appropriate indexation would allow the implementation of longer term incentive targets.

166. In addition to incentives on the SO, incentives on the industry or TOs to reduce losses could also be developed.

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# Section 5
## Black Start

*This section discusses the drivers for change to Black Start provision and impact on costs to the industry.*

### 5.1 Introduction

167. National Grid has an obligation under the Grid Code to ensure that the transmission networks can be re-energised in the event of a total or partial system shutdown. Such re-energisation is known as black start. Black start is defined as a low probability high impact event, so despite the low likelihood of a total or partial system shut-down occurring, contingency arrangements must be in place to enable a timely and orderly restoration of supplies.

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

169. The need to contract for black start capability at an individual generating station is largely driven by the current arrangements at other nearby power stations, the expected longevity of such contracts and the implications involved in improving system restoration.

170. Contracts for Black start services are defined as "Part 2 System Ancillary Services" in the Grid Code. These are categorised as services that are required for system reasons and must be provided by a user if provision has been agreed under a bilateral agreement. However, it is recognised that, due to technical reasons, not all stations can provide the service and that procurement is not based on price alone.

### 5.2 Current Incentive Structure

171. National Grid is currently incentivised to procure black start services required to ensure that restoration of the GB Transmission System is possible in an economic and efficient manner.

172. Current Black start providers are paid an agreed fee per settlement period for the availability of the service. Where the installation or refurbishment of capital assets at a power station would return a valuable black start service, then National Grid may choose to contribute towards the provider's capital costs incurred to provide the black start equipment.

173. Scheduled Black start tests fees are usually not directly included within the contract. The exception being that some providers may choose to set an exercise price for the use of the auxiliary unit. Instead fees are agreed separately for each test.

174. National Grid believes the purpose of the black start test is to test the technical aspects of the black start agreement and not a commercial opportunity. Therefore, reasonable bid/offer prices are agreed in advance. In the event of a black start situation, payment is made in accordance with the BSC.

175. To better reflect the risk profile of black start provision, the black start component could be unbundled from the current bundled BSIS scheme, where it is currently managed. A separate incentive scheme that more accurately reflects the risk profile could be developed.

## 5.3 Black Start Cost Drivers

176. Historic black start costs are shown in the graph below.

177. ‘Other Black Start Costs’ include tests fees and contributions National Grid has made to refurbishment or installation of capital assets at a power station to enable provision of black start capability.

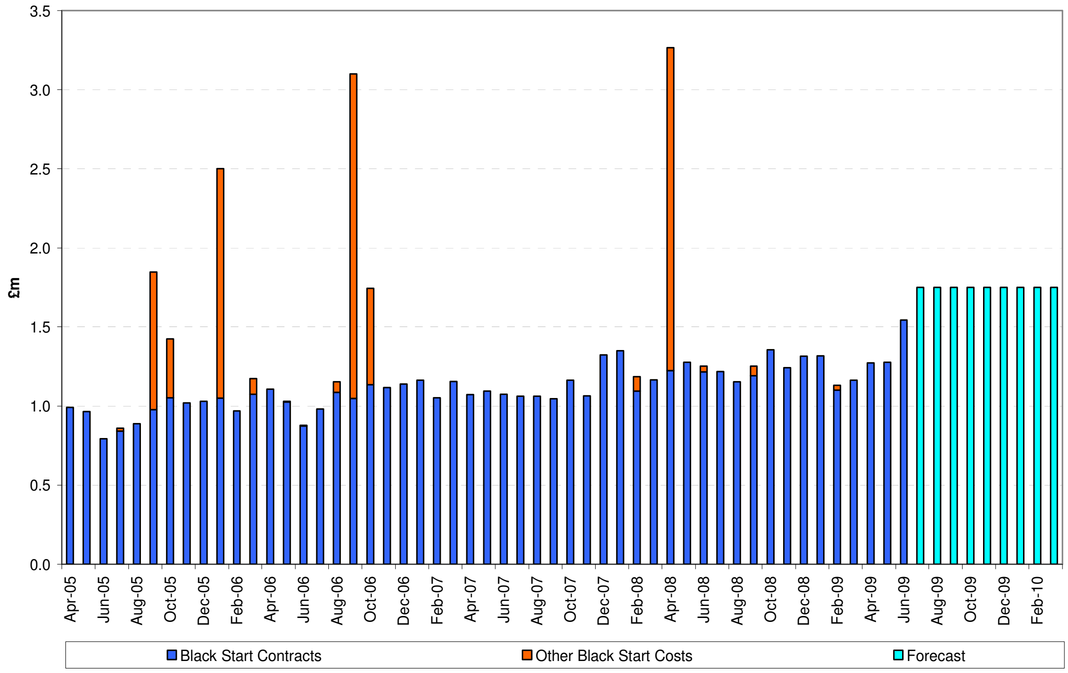


Figure 14 – Black start costs

178. Figure 14 shows a trend of increasing black start contract costs. This is due to increases to contract terms at renewal due to the increased costs submitted by providers.

179. The frequency of spikes of 'Other Black Start Costs' is anticipated to increase as more new providers are sought to replace those Large Combustion Plant Directive (LCPD) opted out providers.

180. We anticipate that this trend in increased costs, coupled with the limited level of mitigation of the increase, will continue until 2012. As the costs for the next two years are reasonably certain (known contract durations and indications of costs of new contracts) we believe that a two year incentive scheme could be developed for black start.

181. Currently there are a number of black start providers where the contracts were developed at vesting and are therefore based on fully depreciated black start assets.

182. Amongst the current fleet of 23 black start stations there are five stations that opted out of the LCPD and will therefore close before 2016. A consequential effect of the closure of these power stations is the closure of the auxiliary gas turbines required to provide black start capability.

183. Therefore, a significant volume of new providers will be needed over the next 2 – 5 years. As recently demonstrated, these new providers are likely to drive up costs as they seek to recover the capital costs of the new or refurbished equipment required to provide a black start service

184. Higher penetrations of intermittent generation and connection of large nuclear units will lead to changes in operating regimes of conventional thermal plant and result in long periods where thermal plant contracted for black start will be left cold.

185. This will limit access to conventional black start providers and may lead to increased warming costs to enable the station to be able to start up in an acceptable time. To effectively manage costs in the future, the ability of new and developing technologies to provide black start services must be assessed.

186. To achieve most cost efficient service for the end consumer whilst maintaining current levels of black start service, National Grid is actively seeking to replace black start providers expected to close before 2016 as well as seeking to increase competition in the provision of this service. Although black start provision is not possible from all generating stations, we have had some success developing new providers and we are continuing to engage with market participants.

187. We continue to review our contracting strategy, ensuring we are contracting competitively while maintaining a cost-effective level of system security.

188. We are currently investigating the feasibility of providing black start services from technologies not included in our current portfolio including:
    - Wind

- Supercritical Coal
- HVDC Interconnectors
- Storage technologies

189. We believe it is necessary to investigate these alternative options at this stage to maintain our portfolio of black start providers towards the end of the next decade.

## 5.4 Incentive Options

190. National Grid believes, against the current generation background and the number of black start providers available, that the current black start component of BSIS has placed an appropriate incentive on National Grid to economically procure black start services.

191. It may be appropriate to continue with the current black start incentive arrangements for the near term. However, the current incentive regime may not be appropriate against a changing generation landscape and the changes in black start providers that will be seen over the next five years.

Question 12 – Do you agree that National Grid should be incentivised on the procurement of black start services for 2010/11 and 2011/12 as under the current scheme framework?
Question 13 - Do you believe that the black start scheme should be extended to a 2 year target?

## 5.5 Review of Black Start Procurement

192. We anticipate a step change in black start costs following the closure of LCPD opted out plant over the next 6 years.

193. Due to the fundamental changes that are occurring within the generation landscape, it may be appropriate to consider the development of the procurement arrangements for black start services in the medium term.

194. This review will need to consider the potential for new technologies and the requirements going forward.

Question 14 – How do you believe black start services are best procured post 2012?

## 5.6 Conclusion

195. Acknowledging that black start costs are currently a small percentage of the total BSUoS costs, we seek to highlight a significant increase in costs that is expected in the future.

196. The impact of LCPD related closures and the future fleet portfolio driven by CO2 targets are likely to have a major impact on the future generation backgrounds. This change in generation portfolio is expected to have an impact on existing black start providers as existing power stations close.

197. We expect an increase in costs for provision of black start services in future years as new providers seek to recover the capital costs of the equipment required to provide black start

198. National Grid believes that the current incentive scheme framework places an appropriate incentive on National Grid to economically procure black start services against the current generation background.

199. With the anticipated changes in generation pattern over the next 6 years, we believe a review of the procurement arrangements for black start is undertaken in the medium term.

# Section 6
## Summary

200. 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.

201. 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.

202. 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.

203. In section 2, we outline the benefits of the current incentive arrangements and the benefits and drawbacks of the current one year bundled scheme.

204. In section 3, we set out the main drivers of reactive power costs and highlighted with areas where National Grid has control over these drivers. We seek views on the development of a longer term incentive and whether the implementation of appropriate indexation would provide any benefits.

205. In section 4, we focus on the level of control National Grid has over the transmission losses volumes and the appropriateness of the current incentive arrangements. We seek views on the possible development of alternative arrangements or the development of the current incentive structure.

206. In section 5 we highlight the changes in black start costs that are anticipated over the next six years. We seek views on whether the current incentive arrangements should continue to be applicable in the near term, and whether a review of the procurement arrangements should be undertaken in the medium term.

207. Input from industry will vital in the development of incentive proposals. Therefore, we would welcome any feedback from the industry on the content of this consultation.

208. If you would like to discuss any items, please contact National Grid using the details contained at the end of this document.

# Section 7
## Consultation Questions

*This section lists the consultation questions from the document.*

### 7.1 Consultation Questions

209. The questions below have been constructed to help us determine the industries view on the potential for the development and implementation of an indexation methodology.

210. 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.

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

### 7.2 List of Consultation Questions

| | |
|---|---|
| 1 | What benefits do you see for the development of an indexation methodology for reactive power costs? What drivers should be included in such an index? |
| 2 | What benefits do you believe there are in the implementation of a longer than one year scheme? |
| 3 | Are there any additional benefits or drawbacks in the development and implementation of an unbundled reactive power incentive? |
| 4 | Please provide your views on the development of the reactive power incentive? Do you see any benefits in changing the current arrangements? |
| 5 | What benefits do you see for the development of an indexation methodology for transmission losses? What drivers should be included in such an index? |
| 6 | Please provide your views on whether the SO can influence sufficient drivers to reduce Transmission Losses? |
| 7 | What benefits do you believe there are in the implementation of a longer than one year scheme? |
| 8 | Are there any additional benefits or drawbacks in the development and implementation of an unbundled transmission losses incentive? |
| 9 | Please provide your views on the development of the transmission losses incentive? Do you see any benefits in changing the current arrangements? |
| 10 | What benefit do you see in developing a transmission losses zonal forecast incentive? |
| 11 | What benefit do you see in the development of a Transmission Losses procurement incentive similar to the Gas Shrinkage incentive? |
| 12 | Do you agree that National Grid should be incentivised on the procurement of black start services for 2010/11 and 2011/12 as under the current scheme framework? |
| 13 | Do you believe that the black start scheme should be extended to a 2 year target? |
| 14 | How do you believe black start services are best procured post 2012? |
| 15 | Did you find the level of information within this consultation informative?<br>What additional information should National Grid provide to explain better? |
| 16 | Do you have any further comments on any aspect of this consultation in relation to the Electricity SO? |

# Appendix A

## A.1 Reactive Power Procurement Default Arrangements

212. For generators that have not entered a market agreement with National Grid, the generator will be paid using the default arrangements outlined in the CUSC. This mechanism is for generators that meet the Grid Code requirements (CC6.3.2) for reactive power provision and are requested by National Grid to provide reactive power services. The current arrangements are based on the generators metered reactive power volumes (i.e. utilisation only) and paid using a reactive power default price. This default reactive power price is indexed to the Retail Price Index (RPI) and the month ahead Power Price (*see part 3.2.1 for calculation*). The same payments apply to both absorption and generation of reactive power.

213. More detail can be found under Schedule 3 of the Connection and Use of System Code (CUSC)[17].

## A.2 Reactive Power Procurement Market Arrangements

214. This service is open to transmission users with and without a Grid Code obligation to provide reactive power. There are two forms of this arrangement: “Obligatory Reactive Power Service” and “Enhanced Reactive Power Services”. The market arrangements enable the reactive power provider to request:
    - an available capability price; and/or
    - a synchronised capability price (£/MVar/hr); and/or
    - an utilisation price (£/MVarh); plus
    - choose of contract length (from a minimum period of 12 months and thereafter in 6-month increments (12, 18, 24, 30, 36 months, etc.))

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

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

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

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

# Contact details

*If you would like to discuss any issue on SO Incentives, please contact us via the contact details below.*

To register your interest in receiving future communications on this consultation process please email: SOIncentives@uk.ngrid.com

**On the web:**

New dedicated web pages for this process are available at the following addresses:

Electricity SO Incentives: http://www.nationalgrid.com/uk/Electricity/
Gas SO Incentives: http://www.nationalgrid.com/uk/gas/

**Talk to us:**

Gas
John Perkins Tel: 01926 656337 john.perkins@uk.ngrid.com

Electricity
Malcolm Arthur Tel: 01926 654909 malcolm.arthur@uk.ngrid.com

General enquiries: SOincentives@uk.ngrid.com