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THE POWER OF ACTION

An Introduction to National Grid Electricity Transmission System Operator Incentives

Balancing Services Incentive Scheme Reference Document

UK Electricity Transmission

November 2010

Executive Summary

1. National Grid Electricity Transmission plc (NGET) is the National Electricity Transmission System Operator (NETSO) for Great Britain and offshore. Under the transmission licence, National Grid is obliged to perform Balancing Services Activities (BSA), which are defined as the operation of the transmission system and the procurement and use of Balancing Services required for reliable operation of the transmission system.
2. The application of financial incentives encourages National Grid to invest in systems and resources to ensure BSA costs and risks are economically and efficiently managed and that innovative ideas and procedures are developed to reduce costs in return for a share of any savings delivered.
3. Balancing Services Incentive Schemes (BSIS) are 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.
4. National Grid consults with the industry during the development of proposed incentive schemes. This document is intended to be used as a reference document for existing and future BSIS consultations, thus reducing the amount of detail required to introduce each separate BSIS consultation. It is hoped that this document will go some way to address some of the industry feedback that commented that many of the consultation documents were too long and contained too much detail. This reference document will ensure that detailed information associated with BSIS consultations is still available, whilst helping to achieve shorter and more concise BSIS consultation documents.
5. This reference document considers all cost components that make up BSIS incentivised balancing costs. This information is set out under three main sections, as follows:
    - energy related products;
    - reactive power, black start and transmission losses; and
    - transmission constraints.
6. This document will regularly be updated to maintain its relevance to the current BSIS and the usefulness to the industry. Feedback from the industry assessing the value of this document is welcome to facilitate future improvements.

   Comments should be sent to **SOIncentives@uk.ngrid.com**

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This section introduces National Grid's role as a system operator and the incentives placed on National Grid to achieve this role efficiently. BSIS is introduced and its relationship with BSUoS costs explained.

1. Introduction to BSIS

1.1 An Introduction to National Grid

7. National Grid Electricity Transmission (NGET) is the National Electricity Transmission System Operator (NETSO) for the onshore and offshore electricity transmission systems in England, Scotland and Wales, defined hereon in as National Grid for simplicity.

8. Under its transmission licence, National Grid is obligated to perform Balancing Services Activities (BSA), which are defined as the operation of the transmission system and the procurement and use of balancing services required for reliable operation of the transmission system.

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

1.2 External System Operator (SO) Incentive Scheme – Balancing Services Incentive Scheme (BSIS)

10. National Grid is externally incentivsed in its role as the system operator for the onshore and offshore electricity transmission systems in England, Scotland and Wales by the Balancing Services Incentive Scheme (BSIS).

11. BSIS provides a focus on key areas where National Grid is able to create value for the industry and consumers by reducing operating costs, and improving the accuracy and provision of information for use by the industry to better facilitate the market.

12. This document focuses on BSIS and aims to be a reference document for existing and future BSIS consultations.

1.2.1 SO Incentive Review

13. Following the 2010/11 BSIS consultation process, Ofgem established an electricity SO incentive review; the objective being the development of a longer term scheme commencing April 2011. The intention is that such a scheme should incentivise National Grid to take a longer term view to SO costs, lead to greater cost transparency and reduce the ongoing administrative burden involved with the development of SO incentive schemes.

14. In order to achieve such a scheme, Ofgem concluded under phase 1 of the review that a number of variables which form inputs to BSIS cost forecast models should be input to those models ex-post as opposed to ex-ante as they are currently, so as to avoid the need to form a view of volatile, difficult to forecast parameters when deriving an ex-ante cost target prior to scheme

commencement (something that has become increasingly difficult in recent years).

15. Instead, the parameters that describe the scheme profile will be relative to a 'target' cost determined using agreed models, ex-ante and ex-post datasets.

- **Ex-ante inputs** will be set prior to scheme start. The same dataset will be used whenever the models are run throughout the scheme and would not normally be updated as the scheme progresses (except under specific agreed circumstances); and
- **Ex-post inputs** would be collated on a routine basis (e.g. monthly) and combined with the ex-ante dataset, to be run through the models to determine the target level of costs that National Grid should be incentivised against, for the period covered by the ex-post data.

16. The use of out-turn data in models, in addition to forecast data, is known as the 'Ex-Ante/Ex-Post Approach' to incentivisation. As the approach is newly-proposed for the incentive scheme commencing on 1st April 2011, a full explanation can be found in the latest 'Initial Proposals' document on National Grid's electricity incentives website[1].

1.2.2 Internal SO Incentives

17. As well as an incentive to manage external SO costs (BSIS), National Grid controllable SO (OPEX) costs are incentivised on a sliding scale basis around a target (which was set for 5 years at TPCR4) but with sharing factors which historically align with BSIS.

18. The rationale for sharing factor alignment is to provide National Grid with the same exposure to internal and external costs and therefore promote efficient arbitrage between its internal OPEX costs and external balancing costs. In practice this means that if National Grid can reduce balancing costs and therefore derive benefits through BSIS by increasing OPEX (e.g. employing more staff) then it has an incentive to do this. Extending the duration of BSIS will increase the scope to undertake such activities.

1.3 Balancing Services Use of System (BSUoS) Charges

19. National Grid's transmission licence conditions specify that it is responsible for the determination and implementation of a GB use of system charging methodology. The Use of System Charging Methodology Statement[2] describes the methodology that National Grid employs to levy charges for the use of the transmission system.

20. National Grid is permitted to derive revenue for the BSA it carries out under the terms of the transmission licence. These costs, as well as any incentivised receipts / payments are paid by the transmission system users via the Balancing Services Use of System (BSUoS) charges.

21. All participants who are subject to the Connection and Use of System Code (CUSC)[3] are obliged to pay BSUoS charges based on the amount of energy each participant has taken from or supplied to the National Grid in each half hour.

[1] http://www.nationalgrid.com/uk/Electricity/soincentives/docs/
[2] http://www.nationalgrid.com/NR/rdonlyres/C20ACF42-4D18-45C1-ACBF-CB52D3D7C481/43444/UoSCMI6R3v10Final.pdf
[3] http://www.nationalgrid.com/uk/Electricity/Codes/

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

- The internal incentive scheme costs include National Grid's internal costs for operating the transmission system. For example, staff and IS overheads.
- The external BSIS costs recover the external costs National Grid incurs when operating the transmission system. These costs include Balancing Mechanism (BM) charges, contracts and trading carried out to minimise the costs of actions.

23. These external costs are grouped in the following categories; constraints, black start, reactive power, energy related services, SO internal costs and incentive payments.

24. Using a recalculated scheme target with an ex-post approach, as and when required, would mean that, rather than using fixed points from the target to describe any cap, floor or dead-band, it would be necessary to calculate them relative to a variable target. The value of the target would be determined by National Grid and provided to the BSUoS calculation system. The system would then use the target to determine the absolute values for the cap, floor, sharing factors and dead-band, in order to calculate the incentive for inclusion into BSUoS Charges. The NIA will also be removed.

25. In its transmission licence the external BSIS costs are referred to as the Incentivised Balancing Costs (IBC) and are defined below. Note that, under the proposed new approach to incentivisation (as described in the Initial Proposals for BSIS from 1st April 2011), the Net Imbalance Adjustment (NIA) term would no longer be required; hence it is shown in italics below.

IBC = [CSOBM + *NIA* + BSCC + TLIC] + [minor terms] **(1)**

Where

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

26. External BSUoS can be expressed as the following

BSUoS(ext) = CSOBM + BSCC + Incentive payment+ [minor terms] **(2)**

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

BSUoS(ext) = IBC – *NIA* – TLIC + Incentive payment **(3)**

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

BSUoS = BSUoS(ext) + Internal SO costs + Internal Incentive payment (4)

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

30. The following sections of this reference document consider the main areas that make up the incentivised balancing costs in BSIS; energy related products, reactive power, black start, transmission losses and constraints.

This section identifies the key actions, taken by National Grid, to manage the system frequency. The timeline of actions used to manage the system is introduced and then each action described individually.

2. Energy related products

2.1 Managing the system frequency

31. Great Britain's nominal operating frequency is 50Hz. In order to maintain the frequency within the statutory limits of 49.5 to 50.5, National Grid has to balance generation with demand on a second by second basis. Too much generation on the system will cause the frequency to rise and too much demand will cause the frequency to fall.

32. To ensure that the system isn't operated outside of the statutory limits, National Grid sets a more restrictive operational frequency limit of 49.8 to 50.2Hz.

33. National Grid takes a number of different actions to ensure that the system frequency is maintained within the statutory and operational limits. The different actions are taken depending on the different timescales required for managing the system. Figure 2 shows the four main actions taken to respond to system frequency fluctuations; margin and Short Term Operating Reserve (STOR), energy balancing, fast reserve and frequency response. The timescales in which each action would be taken ahead of time is described in Figure 2.

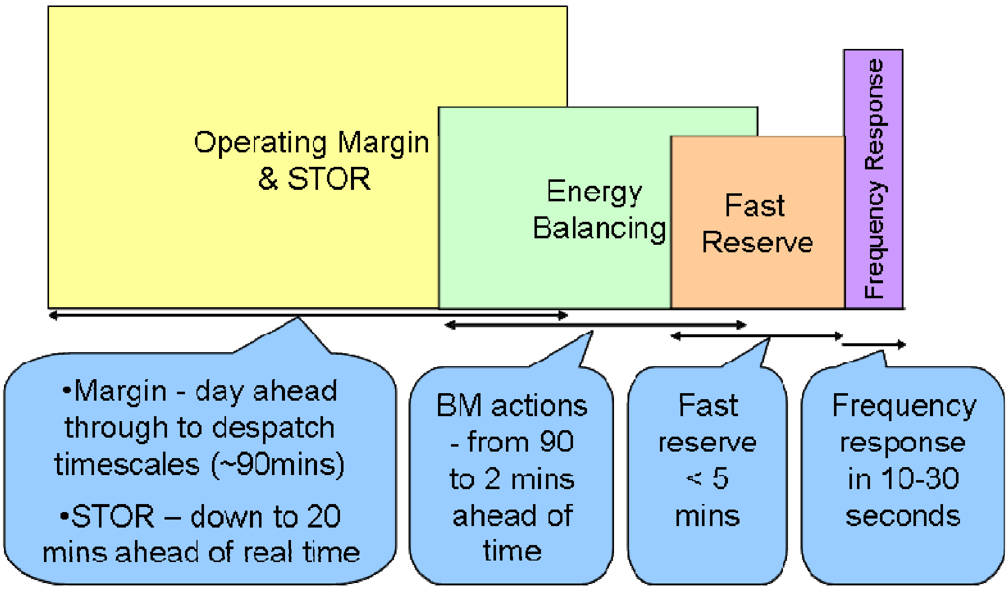

Figure 2: Actions taken in different time scales to manage system frequency

34. The following sections describe each balancing services action in detail.

2.2 Operating Margin

35. The operating reserve requirement, also know as Short Time Operating Reserve Requirement (STORR) is calculated so that the probability of demand not being met is only a total of one day in every 365 days. Where the difference between the sum of the synchronised generation capacity and the forecast demand is less than the operating margin requirement, action must be taken to increase the operating margin. If the shortfall of operational margin is lower than a specified threshold, National Grid issues a Notification of Insufficient System Margin (NISM). Generally the market responds to the issued NISM by supplying more synchronised generation to meet the operating margin requirement.

36. Setting the operating margin is a balance between reducing the risk of demand disconnection and reducing the costs associated with operating margin actions.

37. Operating margin is made up of contingency reserve and operating reserve, as shown in Figure 3.

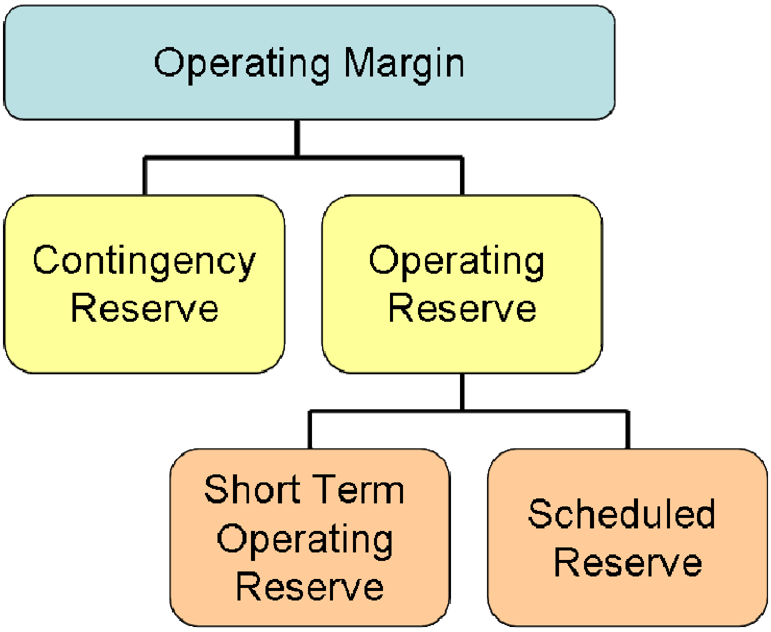

Figure 3: The main components of operating margin

38. Contingency reserve represents a margin of plant that is maintained in a state capable of synchronising in sufficient time to achieve full output in specified timescales. This contingency reserve requirement progressively decreases from the day ahead margin analysis process to zero at the final short term margin analysis stage, approximately four hours ahead of real time. The decrease in contingency reserve requirement represents the reduced probability of plant loss and demand estimation error as real time approaches.

39. Operating reserve is the level of reserve planned at the final short-term margin analysis stage to ensure that there is sufficient generation to meet real time demand. It is made up of:

40. a) Scheduled Reserve: BM units or balancing services providers that are able to regulate output or consumption either automatically or on receipt of despatch instructions. This is required both as positive reserve (often referred to simply as reserve) and negative reserve. Positive reserve is often referred to as headroom and negative reserve is often referred to as footroom. The volume of

scheduled reserve required may be offset by the excess availability of STOR providers above requirement.

41. b) STOR: capacity capable of generating (normally from standstill) or reducing demand within a defined period. STOR is made up of contracted generation or demand that can be called upon to reach full output within 240 minutes and be able to provide this level of output for at least two hours[4].

2.3 Other Operating Reserve Components

42. Costs associated with BM start up and Constrained Margin Management (CMM) actions are categorised under operating margin costs.

2.3.1 BM Start Up

43. The BM Start-up Service gives National Grid on-the-day access to additional generating BMUs that would not otherwise have run, and could not be made available in BM timescales due to their technical characteristics and associated lead-times.

44. BM start up costs relates to the actions that National Grid has to take to ensure that BMUs are ready for use within BM timescales; this includes the process of BMUs "warming up", during which the BMU is being prepared to generate if and when a offer is issued by National Grid.

45. Once a BMU has reached critical operating temperatures, additional fees may be incurred to hold the unit at readiness to synchronise – this is known as hot standby.

2.3.2 Constrained Margin Management (CMM)

46. CMM are actions taken, which have the combined effect of;

a) Replacing sterilised operating margin behind a constraint boundary: Sterilised operating margin refers to BMUs which are unable to achieve maximum output as they are located behind a constraint boundary which cannot transmit all of the necessary power through the available assets. Further information about constraints can be found in section 4 of this document.

b) Increasing the amount of positive reserve available for operation: If a reserve action is undertaken that completely replaces sterilised operational margin, then the costs are assigned to constraint costs. For the action to be assigned to CMM costs, the action must only partially replace sterilised operation margin and partially increase the amount of positive reserve available, as can be seen in Figure 4.

[4] http://www.nationalgrid.com/uk/Electricity/Balancing/services/balanceserv/reserve_serv/stor/

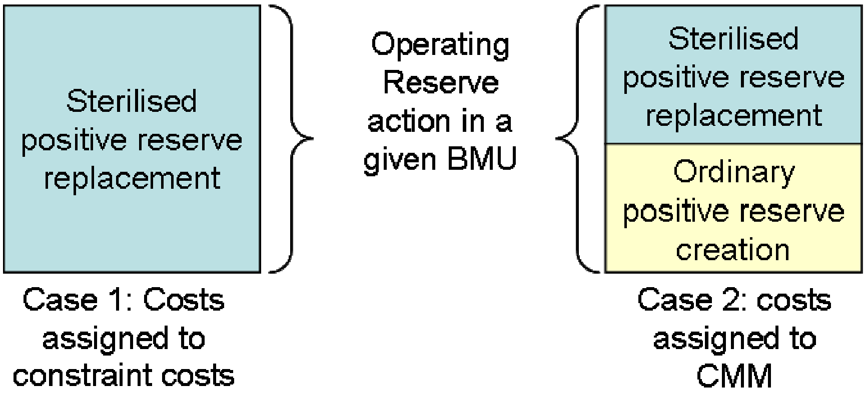

Figure 4: The difference between CMM and Constraint Costs

2.3.3 Negative reserve and Footroom

47. Negative reserve, also known as downward regulation, refers to the capability that National Grid has to reduce the amount of generation output there is on the system. It is necessary to control the level of negative reserve held on the system to ensure that the frequency can be kept within its statutory limits and does not rise out of control due to an excess of generation.

48. In circumstances where demand is low and the majority of generation is operating inflexibly at or near its minimum stable output (i.e. the level at which it can not operate below), there may be insufficient available MW reduction capability (footroom) to allow the required level of negative reserve to be delivered. Actions have to be taken to exchange this inflexible generation with flexible generation – this is achieved by the desynchronising of some of the BMUs, allowing the output of other BMUs to be increased above their minimum stable output. Taking such footroom actions increase the negative reserve capability and gives National Grid more flexibility to respond to changes in the frequency either automatically via frequency response or by instruction. All actions taken to increase the level of negative reserve on the system are classified in BSIS as footroom costs.

49. The volume of footroom actions required is significantly impacted by the availability and the running regime of generation, in particular inflexible plant types like nuclear power stations and wind turbines. High levels of inflexible plant generating during periods of low demand results in flexible generation reducing output, moving towards their minimum stable output, leaving little ability for National Grid to further reduce generation output. This therefore results in an increased volume of footroom actions being required so that National Grid can further reduce output on synchronised machines.

50. The volume of footroom actions and hence costs is likely to increase in the future as the amount of inflexible plant, in particular nuclear and wind generation, increases. The price of the footroom actions are themselves stable, but as the volume of actions increases then so will the footroom costs, going forward.

2.4 Energy Balancing

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

- Buying and selling power in the Balancing Mechanism (BM) (otherwise known as accepting bids and offers)
- Pre-gate closure BM unit transactions (PGBT) and
- Trading

52. The costs accrued by transactions outlined above are called energy balancing actions.

2.4.1 Market Length

53. If generators generate more energy than they have contracted for and suppliers' customers consume less energy than their supplier has bought on their behalf, then the net effect is that there is a surplus of generation on the system. This is often described as a 'long' market.

54. Conversely, if generators generate less energy than they have contracted for and suppliers' customers consume more energy than their supplier has bought on their behalf, then the net effect is that there is a shortfall of generation on the system. This is often described as a 'short' market.

2.4.2 The Balancing Mechanism (BM)

55. The vast majority of energy related actions carried out by National Grid are in the form of bids and offers in the BM. For each settlement period, each BMU submits prices at which National Grid's control centre can instruct them to vary their output during that period.

56. If the market is long, the ENCC instructs generation BMUs to decrease their output (or demand BMUs to increase their requirement) by accepting bid prices. Conversely, if the market is short, the ENCC instructs generating BMUs to increase their output (or demand BMUs to decrease their requirement) by accepting offer prices. For energy balancing purposes, these actions are performed in cost order and feed into the processes undertaken to calculate System Buy and System Sell prices.

2.4.3 Pre Gate-Closure BM unit transactions (PGBT)

57. PGBTs are a tool used by the ENCC to instruct BMUs outside of BM timescales or if they require certainty regarding a BM unit's operating range beyond the BM window. Any BMUs considered able to fulfil the balancing requirement in the required timescales are contacted by the ENCC and the most suitable is selected based on dynamics and prices BMUs must have a Grid Trade Master Agreement signed with National Grid, this is not a requirement for BOAs.

2.4.4 Trading

58. To assist with balancing the generation with the demand by the most cost efficient methods as possible, National Grid's Trading team purchase three different types of forward energy products; Power Exchange Trades, Forward Energy Trades and Energy Balancing Contracts.

59. Power Exchanges are electronic trade matching systems where participants enter prices at which they are prepared to buy or sell electricity. The exchange automatically matches like prices/volumes and the trade is done. This is an anonymous process with the Power Exchange effectively becoming the counterparty to the trade. Standardised products are available on Power Exchanges and range from half-hourly contracts, available for the current day and day ahead (tradable 24 hours a day), to season contracts that cover six

month periods. In between these are contracts for quarter year, months, weeks, days and within-day denominations.

60. Forward Energy Trades are bilateral contracts negotiated between counterparties and can be tailored to suit the requirements of the individual parties. For example it would not be possible to enter into a trade for the first 6 hours of every week-day for a month on a Power Exchange since this is not one of the standardised products. However, if two parties are in agreement, then such a contract could be negotiated 'over the counter'. As well as negotiating direct with a counterparty, trades can be negotiated via 'Brokers'. These trades may at times include BMU-specific or locational terms.

2.5 Trading Agreements and Contracts

61. All parties who want to trade with National Grid outside the BM must have a Grid Trade Master Agreement (GTMA) in place. GTMAs can also contain provisions for entering into PGBTs and locational trades on BM Units; and trades across interconnectors. Note that GMTAs are not required to participate in the BM.

2.5.1 Fast Reserve

62. Fast Reserve is used to control frequency changes that might arise from sudden, and sometimes unpredictable, changes in generation or demand. For example; an incident involving generation disconnection or rapid demand changes resulting from TV pickups. (TV pickups are sudden increases in demand due to public behaviour during commercial breaks or at the end or of TV programmes).

63. Fast Reserve delivers active power through an increased output from generation or a reduction in consumption from demand sources, following receipt of an electronic despatch instruction from National Grid.

64. Active power delivery must start within two minutes of the despatch instruction at a delivery rate in excess of 25MW/minute, and the reserve energy should be sustainable for a minimum of 15 minutes.

65. Fast reserve costs relate to the contracting and utilisation of generating or demand units that provide the service. Fast reserve prices are mostly dependant on tendered and accepted prices, submitted by service providers. Fast Reserve is procured via a monthly process and providers are required to undertake a pre-qualification process and establish a framework agreement prior to tendering.

2.5.2 Frequency Response

66. As described in section 2.1, National Grid must maintain the continuously changing system frequency within the statutory limits, as defined in the National Electricity Transmission System Security and Quality of Supply Standards (NETSSQSS)[5]. To assist with this, National Grid procures frequency response from BMUs, which can be categorised as either dynamic response or non-dynamic response.

67. Dynamic frequency response is a continuously provided service used to manage the normal second by second changes on the system, whilst non-dynamic (static) frequency response is usually a discrete service triggered at a defined frequency deviation.

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

68. National Grid procures three different types of balancing services to assist with frequency control;

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

69. MFR is a dynamic type of frequency response, FFR can be a dynamic or non-dynamic type of frequency response, whilst FCDM is a non-dynamic frequency.

70. The amount of response required at any one time must be enough to maintain the system frequency within the statutory limits if a significant event occurs, such as the loss of the largest power plant on the system.

2.5.3 Mandatory Frequency Response (MFR)

71. All generators bound by the requirements of the Grid Code[3] are required to have the capability to provide MFR. The capability to provide this service is a condition of connection for generators connecting to the transmission system. MFR is an automatic change in active power output in response to a system frequency change.

2.5.4 Firm Frequency Response (FFR)

72. FFR is a commercial service that provides an alternative remuneration structure for the provision of frequency response. This service gives National Grid a degree of stability against price uncertainty under MFR and offers service providers certainty of income. FFR can be provided by generators and demand; it is open to BMU participants and non-BMU participants, existing MFR providers and new providers. FFR is procured on a monthly basis.

2.5.5 Frequency Control by Demand Management (FCDM)

73. FCDM provides frequency response through the interruption of demand. The electricity demand is automatically interrupted when the system frequency falls to below a trigger threshold. The demand customers who provide the service are prepared for their demands to be interrupted for up to 30 minute duration. Historic statistical trends have shown that interruptions are likely to occur between approximately ten to thirty times per annum.

74. FCDM is required to manage large deviations in frequency which can be caused by, for example, the loss of significantly large generation. The service is a route to market for demand-side providers, and compliments other non-dynamic service provision (described in paragraph 69). This service is procured through bilateral negotiations with providers.

2.5.6 Costs associated with frequency response

75. National Grid incurs two main costs by performing such actions; the cost of positioning the units in the responsive mode (bids and offers in the BM) and the usage fee charged by the generators to act in such a mode, which could be submitted monthly (MFR) or tendered (FFR).

2.6 Net Imbalance Volume (NIV) and SPNIRP

76. The Net Imbalance Volume (NIV) is a measure of the real time imbalance between contracted demand and generation, which has to be resolved by National Grid via (for example) acceptances of bids and offers in the BM or via PGBT, as described in paragraph 53. NIV directly impacts the expected cost of

energy imbalance and margin, as does the wholesale power price (referred to as a Single Price Net Imbalance Reference Price or SPNIRP).

77. As described in paragraph 25, the proposed approach to incentivisation removes the need for the concept of NIA; hence its definition will no longer feature in the transmission licence. However, as certain National Grid models will still use SPNIRP, it is defined within Section 8 of this document.

2.7 Other balancing tools

2.7.1 Maximum Generation

78. The maximum generation service is designed to compensate generators for operating outside their normal running parameters, which may be required at times of reduced operating margin. The maximum generation service is instructed via emergency instruction as per section BC2.9.2 of the Grid Code[3]. Energy provided via the maximum generating service is not firm – plant owners are not obliged to deliver if they believe their plant would be put at risk, as they may lead to further plant loss (exacerbating an already tight operating margin).

79. The maximum generation service is only intended to be used in very rare circumstances; the last and only time that this service has been used was back in July 2006. For this reason, no costs for the utilisation of the maximum generation service are usually forecast in the BSIS. If a situation occurs when the maximum generation service is required then the costs of its utilisation will be incorporated in to the BSIS outturn.

80. For more information about any of the balancing services that National Grid procure, refer to National Grid's external website;

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

This section sets out the components associated with reactive power, black start and transmission losses from which Balancing Services costs are incurred.

3. Reactive Power, Black Start and Transmission Losses

3.1 Reactive Power

3.1.1 Introduction

81. Alternating Current (AC) has background energy movement, known as reactive power. The electric and magnetic fields of the AC store and release this reactive power, at different stages of its cycle. Devices which store reactive power from magnetic fields are said to absorb reactive power, whereas devices which store reactive power from electric fields are said to generate reactive power.

82. National Grid manages the voltage of the GB system, to meet transmission licence requirements for secure and stable power transmission and to ensure quality of supply to customers. Voltages are largely determined by the flows of reactive power on the system. National Grid ensures that reactive power is provided on a local basis to meet the constantly varying needs of the system so that there are sufficient reactive power reserves available to meet contingencies, such as generation plant losses and circuit trips.

3.1.2 Controlling reactive power

83. All equipment on the transmission system will generate or absorb reactive power, but not all can be used economically to control the voltage.

84. To assist with controlling reactive power flows, National Grid procures reactive power as a balancing service. It is obligatory for generators that are party to the Grid Code[3] to have the capability to provide reactive power. These synchronous generators can be controlled to absorb or generate reactive power depending on the excitation (a form of generator control). National Grid instructs these generators as to the level of reactive power that should be generated or absorbed to keep the system voltages within acceptable limit.

3.1.3 Reactive power procurement

85. Reactive power is procured via the reactive power market, the arrangements of which are defined in section 3 of the CUSC[3]. The reactive power service is either procured via market agreements, or default payment arrangements.

86. In market agreements generators and National Grid can enter into a market based contract. This service is open to transmission users with and without a Grid Code[3] obligation to provide reactive power. The market arrangements enable the reactive power provider to request any of the following via a tender process;

- An available capability price
- A synchronised capability price (£/MVar/hr)
- A utilisation price (£/MVar/hr)

- Choice of contract length (minimum of 12 months and in 6 month increments thereafter)

87. Default payment arrangements are used for generators that have not entered market arrangements with National Grid. In the absence of such agreements, National Grid pay generators using a reactive power default price, which is defined in the CUSC[3] as a function of wholesale prices and retail price index for reactive utilisation based on metered volumes.

88. The same payment arrangements apply to both absorption and generation of reactive power.

89. More details about both the market agreement and default payment arrangements can be found under schedule 3 part 1 of the CUSC[3] or via National Grid's external website;

    http://www.nationalgrid.com/uk/Electricity/Balancing/services/balanceserv/reactive/obligatory_reactpower/

90. National Grid controls Reactive Power through two Balancing Services, the Obligatory Reactive Power Service and the Enhanced Reactive Service:

    - The Obligatory Reactive Power Service is the provision of varying Reactive Power output. At any given output the Generators may be requested to produce or absorb reactive power to help manage system voltages close to its point of connection. All generators caught by the requirements of the Grid Code are required to have the capability to provide Reactive Power.
    - The Enhanced Reactive Power Service is the provision of voltage support which exceeds the minimum technical requirement of Obligatory Reactive Power Service (including Synchronous Compensation) and Reactive Power Capability from any other Plant or Apparatus which can generate or absorb Reactive Power (including Static Compensation equipment) that isn't required to provide the Obligatory Reactive Power Service. This service can only be provided by generators that exceed the minimum technical requirement of the Obligatory Reactive Power Service.

3.2 Black Start

91. National Grid has an obligation under the Grid Code[3] 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.

92. In general, all power stations need an electrical supply to start up, under normal operation this supply comes from the transmission or distribution system to which they connect. In emergency conditions, such as a total system shut down, this would not be possible, hence allocated black start stations have small auxiliary generating plant located on-site, that provides the electrical supply required for initial generation start up. Common types of auxiliary generators include; open cycle gas turbines and diesel generators.

93. 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.

94. 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.

95. Not all power stations have, or are required to have black start capability; it is a service that is usually considered when the plant is being built. In a black start scenario, individual contracted power stations will be started using auxiliary generators and then used to start other power stations that do not have black start capability. Gradually, then an interconnected system can be established again.

96. Contracts for Black start services are defined as "Part 2 System Ancillary Services" in the Grid Code[3]. 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.

97. Black start providers receive some or all of the following forms of payments for the service that they provide;

- Availability payments – payments for the availability of black start capability on a £/settlement period basis
- Exercise payments – payment for testing of the auxiliary generator. An agreed amount is paid for the exercise in £/MWh and for the metered output, MWh, of the generator.
- Contribution sums – this is a payment from National Grid to install or refurbish assets at a power station to retain black start capability.

98. Due to the low probability, high impact nature of black start, National Grid requires certainty regarding power station's ability to provide the black start service. Hence routine tests are carried out to prove the capability of black start solutions. Costs incurred due to the testing, feed into overall BSIS black start costs.

99. Further information about black start can be found on National Grid's website by the following link;

http://www.nationalgrid.com/uk/Electricity/Balancing/services/systemsecurity/blackstart2/

3.3 Transmission Losses

3.3.1 What are transmission losses?

100. During the transmission of electricity, some energy is 'lost' from the transmission system, usually in the form of heat. This lost energy is called transmission losses; details of these can be found in the Seven Year Statement[6].

101. Transmission losses comprises of two components - fixed losses and variable losses:

- Fixed losses are constant, they occur due to the dissipation of energy through iron cores that are subject to a magnetic field. Transformers, overhead lines and cables are all subject to fixed transmission losses.
- Currently variable losses make up approximately 60%[7] of the transmission losses; they occur in copper components with current flowing through them.

[6] http://www.nationalgrid.com/uk/Electricity/SYS/
[7] To calculate this figure, the fixed losses value from the Seven Year Statement was used and the 2010/11 Transmission Losses target of 6.0TWh.

The more current that flows in the copper component, the more the copper heats up and dissipates energy in the form of heat. Again, overhead lines, cables and transformers are all prone to variable transmission losses.

3.3.2 Transmission losses and BSIS

102. The financial impact of transmission losses can be evaluated using the volumes of transmission losses and the power price. Figure 5 shows that since BETTA go-live, the yearly trend of transmission losses has increased significantly but have more recently begun to level off.

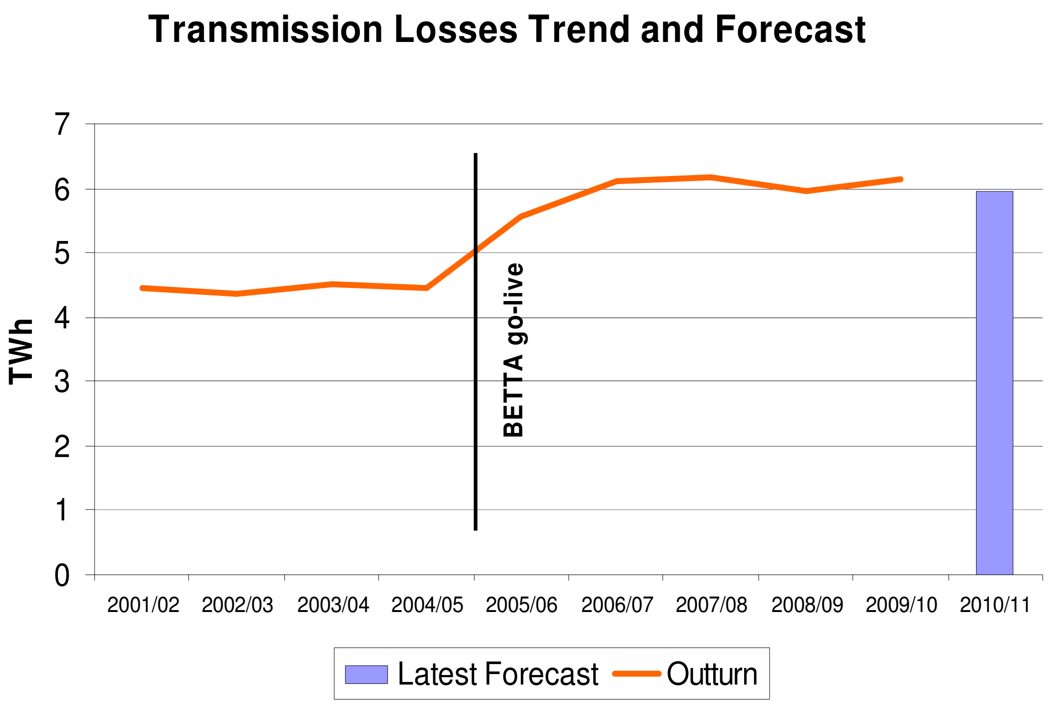

Figure 5: Yearly transmission losses since NETA go-live

103. Forward forecasts, such as The Seven Year Statement indicates that, in 2010/11, the total system losses at peak demand will be approximately 1440MW and that this figure will decrease to approximately 1390MW in 2016/17[8].

104. National Grid is not subject to any balancing costs associated with transmission losses. However, National Grid has been and is still currently incentivised to minimise transmission losses through BSIS. There are currently no direct incentives on generation or demand to reduce or manage transmission losses volumes.

105. As described in equation 1 of section 1.3, TLIC is an adjustment term in IBC.

106. The TLIC term in the formula above, adjusts the BSIS incentive target, if:

- Transmission losses are below the agreed target, hence the target cost is reduced.
- Transmission losses are above the agreed target, hence the target cost increases.

---

[8] http://www.nationalgrid.com/NR/rdonlyres/ADEA146A-BD43-48F3-AC13-035B6AE9D5AC/41464/NETSSYS2010Chapter7.pdf

107. To convert the transmission loss volume into a cost, the current incentive uses a reference price. The transmission losses reference price is based on the forward price plus an adjustment to replicate the shadow price of carbon[9].

3.3.3 Reducing transmission losses

108. National Grid can influence the volume of transmission losses by:

- Evaluating which BOAs to take in the BM.
- Changing transmission running arrangements
- Changing voltage profiles
- By investing in transmission equipment that minimises the impact on transmission losses

109. The further away the generation is from the demand the higher the volume of losses will be, relative to the volume of electricity transmitted.

110. Hence, evaluating which BOAs to take in the BM, could lead to reducing transmission losses if generators closer to demand are chosen in preference to those further away. However, transmission losses are but one factor to be considered when deciding which BOAs to accept in the BM, along with economic and system-related factors (such as the provision of frequency response).

111. Changing transmission running arrangements, i.e. different network configurations can influence transmission losses by utilising routes with lower loss characteristics.

112. Increasing voltage profiles influences the transmission losses by reducing the current flowing through the transmission equipment and hence the amount of energy that is lost by heat.

113. Modern transmission equipment is designed to have lower transmission losses. The transmission owner has a requirement to consider the procurement of low loss equipment when replacing or installing assets.

[9] http://www.decc.gov.uk/assets/decc/what%20we%20do/a%20low%20carbon%20uk/carbon%20valuation/shadow_price/background.pdf

This section sets out the background to constraint costs and discusses the main drivers for volumes and costs. The history of constraint costs is discussed along with forecasts of the costs going forward in the future.

4. Constraints

4.1 What is a constraint?

114. A constraint occurs when the capacity of transmission assets is exceeded so that not all of the required generation can be transmitted to other parts of the network, or an area of demand cannot be supplied with all of the required generation.

115. The volume of a constraint refers to the amount of generation that the transmission capacity is exceeded by i.e:

Volume of constraint = Volume of generation - demand - capacity of transmission system

116. As shown in Figure 6 below, as generation and demand vary, the volume of constrained generation also changes. 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.

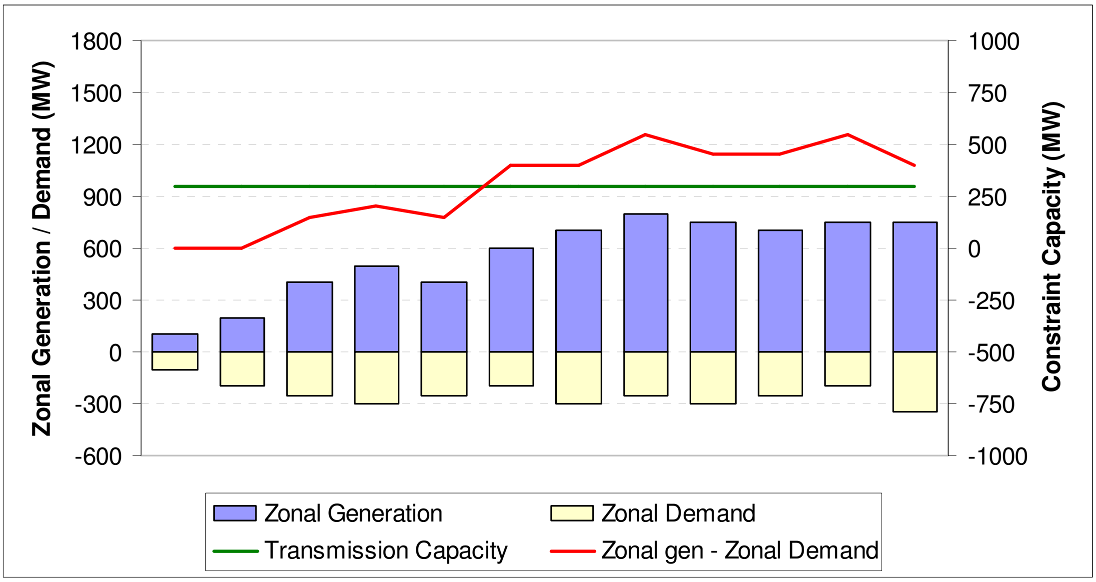

Figure 6: Volume of constraints

117. 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.

4.2 Transfer capability

118. The physical capability of the transmission system is limited by the thermal limitations of the transmission equipment, voltage limits and generator stability.

119. Power transmission leads to the heating of the transmission equipment.

120. The thermal capability of the equipment is based on the ability of an asset to dissipate heat; if the temperature is allowed to exceed its thermal capability limit then a premature failure of the asset could occur. This can lead to cascade tripping and widespread system disturbance. The heating effect can be managed through the control of power flows.

121. As well as the transmission system having a thermal capability limit, the distribution network also has a thermal capability limit. This has to be taken into consideration when National Grid is managing the power flows within the network.

122. Planned and operational voltage limits are defined for the transmission system by the National Electricity Transmission System Security and Quality of Supply Standards (NETSSQSS)[5]. These limits apply to steady state conditions and post system disturbances and ensure that the power quality is maintained and that there are sufficient voltage margins to secure system operation.

123. The ability of the transmission system to remain in synchronisation before, during and after system disturbances depends on the robustness of the connections between the generators and the transmission system and the stability of the generators. If the system was to become unstable then generators may lose their synchronisation with the system in terms of speed or polarity. This can result in damage to the generators and transmission equipment.

4.3 The history of constraints

124. Prior to incentivisation in 1994, constraint costs were increasing significantly year on year, as shown by Figure 7. In the year 1994-5, National Grid was incentivised to reduce the escalating constraint costs. Post incentivisation constraint costs reduced on a yearly basis due to a combination of transmission system reinforcements, new working methods and improved transmission outage planning arrangements.

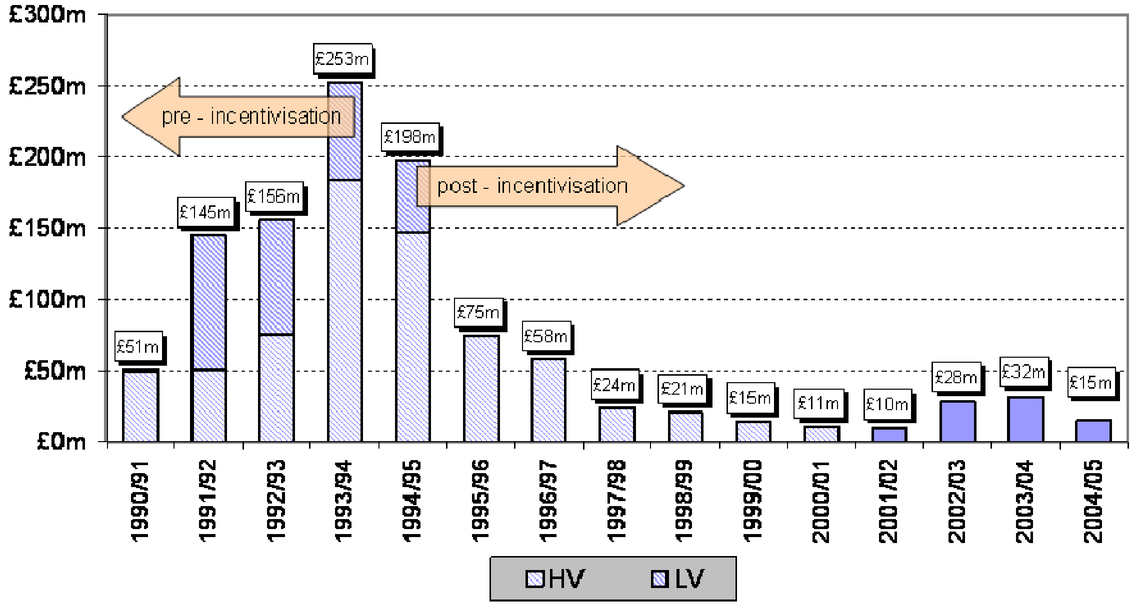

Figure 7: England and Wales constraints outturn pre BETTA

125. Post BETTA, constraints costs increased five fold (2004-5 year shown in Figure 7 compared with 2005-6 year shown in Figure 8).

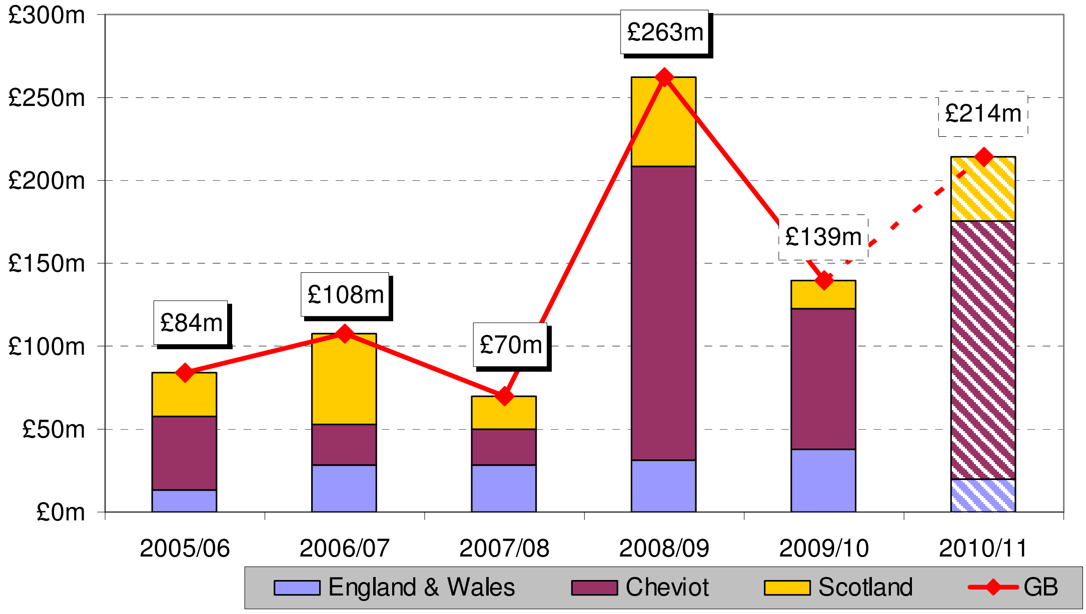

Figure 8: Great Britain constraint costs post BETTA

126. Prior to the introduction of BETTA, the commercial availability of the Cheviot boundary was limited to the physical transmission capability. However, when BETTA was introduced, the commercial limit set at the physical transmission capability of the boundary was removed. This meant that 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[3].

127. Under the post BETTA commercial arrangements described above, the Cheviot boundary does not have the physical capability to accommodate this new

commercial arrangement. Hence the Cheviot boundary has not and still does not comply with the requirements of the NETSSQSS5. For the time being, the respective TOs have applied and been granted a derogation on the Cheviot boundary so that it can still be utilised whilst still being non-compliant.

128. As the Cheviot boundary has a lower capability than the volume of Scottish generation requiring transportation, the cost of constraints is set to increase as the amount of new generation in Scotland increases. In order to connect this significant amount of new generation in Scotland, without further increasing the cost of constraints, the TOs have embarked on a programme of reinforcement and expansion, known as the Transmission Investment for Renewable Generation (TIRG) works.

129. The outages taken to complete the TIRG works have in recent years caused constraint costs to amplify due to the increased boundary capability limitations during these outages. These outages have reduced the transfer capacity of the Cheviot boundary and have increased constraint volumes

130. The Connect and Manage regime was introduced on 11th August 2010. The Connect and Manage model features socialised costs, under which all new generation will be able to apply for an accelerated connection based on the time taken to complete their 'enabling works', with wider network reinforcement carried out after they have been connected.

131. The period of time between connection (following completion of enabling works) and completion of wider network reinforcement may require derogation against the level of system capacity required under the NETS SQSS and so may give rise to increased constraint costs.

4.4 Constraint costs

132. National Grid procures balancing services to manage system flows and alleviate constraints. Since the implementation of BETTA, constraint costs have been broken down by category and location. Constraints can occur under intact, planned outage and fault outage network conditions.

4.4.1 Constraints under intact system conditions

133. 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.

4.4.2 Constraints under planned outage conditions

134. Removing equipment from service for construction work or maintenance increases the power flowing on other system routes. This can intensify existing system issues and can result in additional constraints or create wholly new ones. The majority of constraint costs are typically due to planned outage work on the system.

4.4.3 Constraints under fault outage conditions

135. Equipment failure or damage requires an outage to repair or replace the equipment. 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.

136. When any constraint is managed by limiting or increasing the output of a generator, costs are incurred. Other actions can be taken to alleviate

constraints such as, intertripping, forward trading or bi-lateral contracts to change or limit generator output.

137. Intertrip services are required as an automatic control arrangement where generation may be reduced or disconnected following a system fault event to relieve localised network overloads, maintain system stability, manage system voltages and/or ensure quick restoration of the transmission system. There are two types of intertrip service, commercial intertrips, and system to generator operational intertrips.

138. System to generator operational intertripping can be used to alleviate constraints, which generally exist because of the system conditions occurring at the time that a generator signs their transmission connection agreement, through the CUSC[3] Costs associated with system to generator operational intertripping include a capability fee and a tripping fee. The capability fee includes the cost of maintenance of the intertrip equipment and the training of staff. The tripping fee includes the costs associated with the contract energy imbalance that occurs when an intertrip trips due to fault.

139. Commercial intertrips are used to alleviate wider system issues, including constraints; they may be agreed at the time of a connection agreement or negotiated on an ad-hoc basis. The fees associated with commercial intertrips vary depending on the agreements made, but such fees can include an availability fee, and/or arming fee and a tripping fee if the intertripping facility is actually used.

This section formalises the requirement for industry feedback on the value of this document to make it an even more useful source of reference for future BSIS consultation documents.

5. Industry feedback

140. This document has been produced to provide the industry with a reference document for future BSIS consultations. Some of the industry has commented that in past consultation documents, too much detail was included in the documents and they were too long. National Grid has aimed to address this feedback by producing this reference document.

141. This reference document retains and adds to the detailed information that has historically been available in every consultation document and eliminates the need for it repeating in each separate consultation document. The will lead to shorter consultation documents with the availability of this reference document for extra detail where required.

142. To make this reference document as useful and relevant as possible, feedback from the industry is required. If you would like to provide any comments or feedback on this document, then please email:

soincentives@uk.ngrid.com

Question 1: Does this document clearly explain the ongoing concepts of the incentive scheme?

Question 2: Does the document fully support Initial Proposals, if not why?

Question 3: What additional information would you like to see included in the reference document in future?

6. 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:

The 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/

Contact us:

Gas
Juliana Urdal Tel: 01926 656195 juliana.urdal@uk.ngrid.com

Electricity
Ian Pashley Tel: 01926 653446 ian.pashley@uk.ngrid.com

General enquiries: SOincentives@uk.ngrid.com

7. Glossary of terms

This section of the document contains a glossary of terms used in the electricity transmission industry

There are a number of acronyms and abbreviations used in the electricity transmission industry. To assist readers of the BSIS consultations, the following glossary of terms has been compiled.

Glossary of Terms	
Abbreviation	**Meaning**
ABSVD	Applicable Balancing Services Volume Data
ACS	Average Cold Spell
AW	Available Window
BA	Bilateral Agreement
BBL	Bacton – Balgzand Link
BC	Balancing Code (in Grid Code)
BCA	Bilateral Customer Agreement
BCM	Billion Cubic Metres
BETTA	British Electricity Trading and Transmission Arrangements
BM	Balancing Mechanism
BMS	Bilingual Message Sender
BMU	Balancing Mechanism Unit
BMRA	Balancing Mechanism Reporting Agent
BMRS	Balancing Mechanism Reporting Service
BOA	Bid Offer Acceptance
BPS	Balancing Principles Statement
BS	Balancing Services
BSAD	Balancing Services Adjustment Data
BSC	Balancing Settlement Code
BSCC	Balancing Service Contract Costs
BSIS	Balancing Services Incentive Scheme
BSSG	Balancing Services Standing Group
BSUoS	Balancing Services Use of System
CC	Connection Conditions (in Grid Code)
CCGT	Combined Cycle Gas Turbine
CCL	Cap Committed Level

Glossary of Terms	
Abbreviation	**Meaning**
COP	Call Off Period
CPN	Capped Physical Notification
CSOBM	Cost of System Operation in the Balancing Mechanism
CUSC	Connection Use of System Code
CWV	Corrected Weather Variable
DCI	Demand Control Imminent
CECC	Department of Energy & Climate Change
DNO	Distribution Network Operator
DNS	Domain Name Server
DP	Darkness Peak
DPM	Default Payment Mechanism (Reactive Market)
DR	Disaster Recovery
DSWG	Demand Side Working Group
E3C	Energy Executive Committee
ECVAA	Energy Contract Volume Aggregation Agent
ECVNA	Energy Contract Volume Notification Agent
EDL	Electronic Despatch Logger
EDT	Electronic Data Transfer
EELP	Embedded Exempt Large Power Stations
EI	Emergency Instruction
ELCC	Effective Load Carrying Capability
ENCC	Electricity National Control Centre
ENTSOe	European Network of Transmission System Operators for Electricity
ERPS	Enhanced Reactive Power Service
FCDM	Frequency Control by Demand Management
FSA	Financial Service Authority
FSC	Fuel Security Code
FFR	Firm Frequency Response
GBA	Gas Balancing Alert
GBSO	Great Britain System Operator
GC	Grid Code
GTMA	Grid Trade Master Agreement
HF	High Frequency
HRDR	High Risk Demand Reduction
HSTT	Hot Standby Target Time
HV	High Voltage
HVDC	High Voltage Direct Current

Glossary of Terms	
Abbreviation	**Meaning**
IAE	Income Adjustment Event
IBC	Incentivised Balancing Costs
IFA	Interconnector Framework Agreement
IP	Internet Provider
ITT	Invitation to Tender
IPC	Initial Proposals Consultation
IU	Interconnector User
IUK	Interconnector UK (Gas)
LCPD	Large Combustion Plant Directive
LF	Low Frequency
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
MBSS	Monthly Balancing Services Statements
MCRP	Mid Channel Reference Point
MEL	Maximum Export Limit
MGMEL	Maxgen Maximum Export Limit
MGS	Maximum Generation Service
MIS	Main Interconnected System
MNZT	Minimum Non Zero Time
MPSI	Megawatt Profile Submission Interface
NDZ	Notice to Deviate from Zero
NETA	New Electricity Trading Agreements
NGET	National Grid Electricity Transmission
NIA	Net Imbalance Adjustment
NISM	Notification of Insufficient System Margin
NIV	Net Imbalance Volume
NTS	National Transmission System
OC	Operating Code (in Grid Code)
OCGT	Open Gas Cycle Turbine
OPMR	Operational Planning Margin Requirement
ORPS	Obligatory Reactive Power Service
TSD	Total System Demand
TSP	Transmission System Operator
UKCS	UK Continental Shelf
WOR	Winter Outlook Report

8. SPNIRP

This section of the document defines the Single Price Net Imbalance Reference Price (SPNIRP), which is a form of market reference priced used by National Grid in its BSIS models. In the current (2010/11) incentive scheme it forms part of the Net Imbalance Adjustment (NIA). Since, under the proposed new approach to incentivisation set out in the Initial Proposals for BSIS from 1st April 2011, there is no longer a need for NIA, the definition if SPNIRP will disappear from National Grid's transmission licence. Accordingly, it is presented here for completeness. The text below is an extract from the National Grid Electricity Transmission Licence (as at 1st November 2010): Schedule A, Part B4.

> For the purpose of paragraph 9 of Part 2(i) of special condition AA5A, the term NIA*j*, which is the net imbalance volume reference price for each settlement period j, during relevant year t, shall be derived as follows:
>
> (a) (i) where APXUKHHj and APXUK4Hj data are published in respect of the relevant settlement period j then:
>
> $$SPNIRP_j = (0.5 * APXUKHH_j) + (0.5 * APXUK4H_j)$$
>
> (ii) where APXUKHHj data are published and APXUK4Hj data are not published in respect of the relevant settlement period j then:
>
> $$SPNIRP_j = APXUKHH_j$$
>
> (iii) where APXUKHHj data are not published and APXUK4Hj data are published in respect of the relevant settlement period j then:
>
> $$SPNIRP_j = APXUK4H_j$$
>
> (iv) where neither APXUKHHj data nor APXUK4Hj data have been published in respect of the relevant settlement period j then:
>
> $$SPNIRP_j = SPNIRP_{j-1}$$
>
> where:
>
> SPNIRPj means the single price net imbalance volume reference price for each settlement period j.
>
> j in all cases shall mean a settlement period (being a half an hour) as defined in the BSC.
>
> j-1 the settlement period immediately preceding the relevant settlement period j.

APXUKHHj means the APX Power UK volume weighted reference price for each settlement period j based on the traded prices of half hourly spot contracts.

APXUK4Hj means the APX Power UK weighted average price in respect of all four (4) hour block market contracts delivered within the EFA block applying to those settlement periods j. In order to derive the APXUK4Hj price in respect of each relevant settlement period j the EFA block containing the relevant settlement period j shall be used.

EFA block means the six four hourly blocks within the EFA day (being 23.00 hours to 23.00 hours in the immediately following day) set out in the table below:

Block	Time
1	23:00 to 03:00
2	03:00 to 07:00
3	07:00 to 11:00
4	11:00 to 15:00
5	15:00 to 19:00
6	19:00 to 23:00

(b) The term NIAj shall be derived as follows:

where TQEIj <0

$$NIA\,j = SPNIRP\,j * (MLM1 * TQEI\,j - VO)$$

where TQEIj >0

$$NIA\,j = SPNIRP\,j * (MLM2 * TQEI\,j - VO)$$

where TQEIj =0

$$NIA\,j = SPNIRP\,j * (-VO)$$

Where TQEIj is the total net imbalance volume as defined in the BSC in force immediately prior to 1 April 2001; and

where in respect of the relevant year t, the terms MLM1, MLM2 and VO shall have the value ascribed to those terms in the following table:

MLM1	1.25
MLM2	0.9
VO	450

9. Amendments record

As this document is intended to be an evolving one, which will be updated on a regular basis by National Grid, there is need for an amendments record.

Version	Date	Summary of Changes	Author
1	01/02/2010	New document	Sally Nicholson
2	22/11/2010	Updated document	Charon Balrey